



**HARVARD ELECTRICITY POLICY GROUP
NINETIETH PLENARY SESSION
FOUR SEASONS GEORGETOWN
WASHINGTON, DC
THURSDAY AND FRIDAY, MARCH 22-23, 2018**

Rapporteur's Summary*

Session One.

Regional Reliability Standards: Requirements or Replaceable Relics?

The public policy and political rationale for reliability standards is clear. Electricity is central to our social and economic well-being. While there is clarity on the broad objective, defining an acceptable level of uncertainty, based on loss of load probability calculations, has centered on the “one day in ten years” and N-1 standards for planning by high voltage system operators. Ironically, the “one day in ten year” standard, in particular, is not applied to distribution systems, the source of the vast majority of service outages. To the extent that the applicable reliability standard has an economic basis, it should be based on value of lost load (VOLL) calculations. The latter, of course, is an aggregated society-wide determination. Individual consumers have widely varying levels of tolerance for service interruptions, and many customers now have individualized options for dealing with the imminence of, or actual curtailment, such as demand response, reduced consumption or self-generation, enhanced by the availability of smart technology enabling rapid response. On the other side of the equation are increased consideration of natural gas supply, pipeline constraints, importance of ancillary services, and other potential for interruptions that may be of sufficient concern to ratchet down on reliability planning criteria. Given all of those realities, how relevant are reliability standards in today's marketplace? Is the “one day in ten years” standard or the N-1 constraint still appropriate? If not what ought to replace them? Given that customers have widely varying degrees of tolerance for service outages, is it possible to provide differing reliability criteria for different customers? If so, do we do it by how planning is carried out, or simply by variations in pricing to reflect different assurance of reliability?

Moderator.

This morning's panel is designed to focus on the the interplay between the economics and reliability issues, and where we need reliability

intervention in the form of rules or enforcement, and where appropriate pricing or other economic practices can weigh in.

1

* 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.

Speaker 1.

Thank you. During my over nine years as a utility regulator in Texas, I spent about six years on this kind of question. And what I found is that in both state and even federal regulations, at the commission level, they never really focus on the key question, which is the reliability standard and the nature of it. They've always accepted it as a given. It's always been there. There's not much inquiry into, "Well, is it even rational?" and it's these reliability standards that ultimately drive a lot of other policy questions with respect to the nature of resource adequacy. And so, if the foundation itself is flawed, that's a problem.

I came to this in sort of a unique way, because I had no real background in the electric markets or in power--and that's the qualification for being a utility commissioner, at least in Texas, generally. Probably everywhere.

It started in 2011. Even before then there had been discussions and concerns over the reserve margin down in Texas. You had ERCOT forecasting this incredible load growth, in some cases four percent a year, and when I talked to them offline, and I asked where the forecast came from, they said, "Well, it's derived from the standards used around the state. There's the one in 10 standard of loss of load expectation, and the load growth formula itself is based on a Moody's high level figure." The result was, we were showing, within three, four, five years, a really, really low reserve margin.

So that was the first issue. And that got me sort of looking into it. Then we had an event in February 2011, the Great Freeze. We had about seven hours of rolling blackouts that ERCOT implemented to keep the grid stable. And it just so happened that, I think it was two days before, the offer cap had gone from \$1,000 to \$3,000. Now that change had been in place for, I think, four, five, six years, baked into the rules as we

went to the nodal market. That obviously caused a lot of questions. The generators, or most of the IPPs, used that as an argument, "Oh, we've got this low reserve margin. This is the problem. We've got to implement a capacity market, or some other mechanism." That led to a long debate at the Commission that focused on resource adequacy.

At the time, I questioned the load growth forecast. But at the time, I didn't even question the reserve margin. I just assumed, "Well, it must be based on something that was sound." During the course of the debate, I think we hired Brattle, in part because we deadlocked, but to actually look at the problem of resource adequacy, and even though at the time I was disappointed in the recommendations, the report itself, in 2012, really had some interesting facts and information that got me thinking about this question of the reserve margin, because they pointed out that (these are my words, not theirs) there was little real foundation upon which the one in ten standard, in particular, was based. It didn't measure either the magnitude or duration of outages. And in Texas our standard was one event, regardless of the amount of time, in 10 years. They also pointed out, in the course of the discussion, that the one in ten "standard" is not really a standard. The "one" varies widely across the country in those areas that use it. In Texas, it's one event. I think ERCOT actually measures it in an hour, but it's short. If you go to SPP, at the other extreme, it's 24 hours in 10 years. Well, that results in very different reserve margins.

I also discovered sort of an interesting fact, which was that there were areas that didn't use it at all. The Southeast (interestingly, vertically-integrated country) tended not to use the LOLE one in 10 standard. Now, they didn't use a pure economic model. They tended to juice it up, as I was told by one regulator, to avoid the call from the governor.

So that, in turn, then led again to a robust debate over a capacity market, but I kept pointing out, “We’re missing something here.” And about the same time ERCOT also had been working for several years on re-doing their load forecast methodology. And they finally threw out the old model, and did their own custom model, which lowered the forecast. That alone had the effect of keeping the capacity above the reserve margin for a number of years. That allowed me, in February 2014, to file with the Commission a memo that asked my colleagues to consider what we really need to study.

At the heart of the concern is the reserve margin and the basis of the reserve margin and what it means. And in Texas it was always a target. It was never mandatory. But it was used all the time by those who wanted more money, which I understand. The generators of the time were faced with low gas prices. That’s the marginal fuel in Texas. They were faced with the explosion of renewables that were subsidized, and that’s still a problem. They never came out and said it outright, but they always implied that, well, if you don’t do something and the reserve margin gets too low, NERC is going to get involved, which means the Feds, and they’ll require you to do something. It’s not clear to me that was the case. And I’m glad there’s somebody from NERC here, because the NERC standards, as I understood them at the time and still do, really have more to do with the operation of the grid on daily basis--the actions regulators take to avoid total collapse of the grid. I don’t want to say there’s no connection between installed capacity and reliability. That would be stupid. But the one in ten standard, I think, has resulted in really uneconomic decisions.

So that led to the second important report (and all these reports are available on the Commission web page). We commissioned Brattle to go back

and look at well, what is the economically optimal reserve margin in Texas, based on the reforms that we have implemented, and what would be the expected equilibrium reserve margin, again, based on the reforms that we had done? And, to my credit, we had implemented, in the interim, a series of pricing reforms in ERCOT. We had raised the offer cap to \$9,000. We had implemented an Operating Reserve Demand Curve to improve scarcity pricing when conditions warranted it. In 2014, Brattle filed the report and came back with, “Well, the economically optimal reserve margin would be 10.2 percent.” The expected equilibrium reserve margin based on the reforms we had made would be 11 and half percent. If you wanted to stick with the old one in 10 standard, as used by ERCOT, it would require 14.1 percent reserve margin.

Now, there’s one other important fact here that formed my thinking, and it’s called experience. There are those who say, “Well, that’s anecdotal.” But the only two times in Texas that we’ve had statewide rolling blackouts were when we had installed capacity reserve margins well in excess of the target reserve margin. In 2006, in April, when ERCOT had to implement these rolling blackouts, why? Because it was the early days of managing wind. The wind in West Texas had suddenly disappeared. The month of April is also when all the units are down, or a lot of the units are down for maintenance, and the temperatures hit 100 degrees. A Black Swan event. The other time was February 2011. A deep, deep freeze blew through. I’d never seen one come through. It’s a sight to behold, particularly in West Texas, when you can see it coming. The temperatures dropped below freezing for I think it was three or four days. I think it was 30 percent of the generating fleet that either failed to start in the morning or tripped off or came on and off, and ERCOT had to implement rolling blackouts. The last time we had a freeze like that was 22 years earlier. Again, a Black Swan event. I think at the

time we had a 16 or a 17 percent installed capacity reserve margin. The point I then tried to make in the discussions was that even if we implemented a mandatory reserve margin in order to maintain a 15 percent reserve, or whatever number, that doesn't guarantee that you're not going to have a problem. So why are you paying all this money? And if that's the case, which at least in Texas it had been historically, you've got to explain to me what we're paying the money for.

And, again, I'm not against high prices. The reforms we implemented in the energy market could result in astronomical prices, although I think we've only hit \$9,000 now on one day since it was implemented, and that was for about 15 minutes. But the therapeutic benefits of that price exposure have driven something else, and that was the other piece that came out of the original 2010 Brattle report. Buried in the report, on page 70 and 71, they pointed out that if we had enough demand response, based on price (at the time they estimated 3600 to about 5500 megawatts) that that would be enough to maintain reliability. So that's the other piece of this which I think is overlooked.

In Texas, what we saw after 2011, with the exposure to high prices (and this was really exposure at \$3,000 and then \$4500 when we raised it shortly thereafter), was that you really saw a lot of interest in demand response from large customers and load serving entities, not because they felt it was the right thing to do, but because they wanted to avoid the price risk. And it's turned out now that we're at probably somewhere north of 2,000, I think, megawatts of price-responsive load. Now, they also invested in it for other reasons, some of which Bill Hogan doesn't like, around the transmission cost allocation, but the truth of the matter is, once you invest in the technology, you can use it for

multiple reasons that are economic. So, with that. I look forward to discussion.

Speaker 2.

So, NERC's history goes back to its formation in 1968--and that, of course, came after the November 1965 blackout. And it started off as a voluntary organization.

So, in 1997, legislation was originally proposed to create mandatory and enforceable standards for the bulk power system. And, of course, after the 2003 blackout, Congress introduced the Energy Policy Act and introduced the creation of an electric reliability organization. In late 2006, NERC was certified by FERC as that organization to fulfill that role. And by 2007 the first set of mandatory and enforceable standards were introduced, with additional cybersecurity standards coming two years later.

NERC's mission today is to promote a highly reliable and secure North American bulk power system and to do this effectively and efficiently, and ultimately to reduce risks to the system. We aim to accomplish this through the development of risk-responsive standards. NERC also maintains objective risk-informed compliance monitoring, mitigation, enforcement and entity registration. We also developed our reliability assessments, and I look forward to speaking to those later, particularly in regard to ERCOT. And, of course, these goals are all carried out through coordination with our eight regional entities.

NERC's reliability standards are ultimately applicable to entities that plan and operate the system and, as Speaker 1 mentioned, it really is more focused on the operation side. Other standards focus on topics including system protection and maintenance, training, infrastructure protection, and system restoration.

So, when you think about the system, traditionally, 60 plus years ago, it started off with just conventional and hydro generation. And, generally, policies, security, economics-- those were all clear drivers for reliability on both the distribution side and the BPS (bulk power system) side. But as we move forward here the system becomes more complex. Load forecasts are complicated by demand side resources and energy efficiency. And, more recently, we have a potential rapid onset of electric vehicles and substantial growth in resources that are located behind the meter. This can further complicate the situation for system operators, who have to balance not only increasing variability on the generation side, with more wind, but also increasing variability on the demand side. So, the smart grid is really helping to bridge this gap, and it is informing customers as well as system planners and operators, and that ultimately increases, not only efficiency, but also system reliability. Of course, the smart grid also introduces certain security concerns that we also need to be aware of, and we have cybersecurity standards as well to address some of those concerns.

But really there are three themes that have emerged here as the system continues to evolve. First, of course, is the resiliency of the system. And given that this is an increasingly relevant topic as these extreme weather events are occurring, I really raise the questions about the area's resource mix. We're looking at things like fuel assurance--availability and deliverability. Second, demand response, distributed generation, and micro grids will really substantially impact how we assess reliability. And, finally, there are, of course, the physical or cybersecurity risks that are a growing topic of discussion.

But with the changing resource mix, particularly in specific areas of the North American system, we can no longer simply assess reliability the way

it has been done for decades. We have to go far beyond that, and in our assessments we're starting to look at not just reserve margins, but also at essential reliability services, because that's really a major piece of the picture that you really need to reliably plan and operate the system. So, we're exploring U.S. measures. We're collecting data to better understand the thresholds, and really, in certain pockets of the North American system, it warrants additional analysis.

Resilience is something that many in the industry consider to be built into existing planning processes, but it's important to really identify what resilience means for each area. The Department of Homeland Security has a critical infrastructure report that came out a couple years ago, and they really split capacity into two categories. There's the adaptive side and the absorptive side. And really it's the ability of the system to either take a hit and keep moving or, on the other hand, how it responds to that initial hit and adjust to it. So, we've certainly done that in some of our assessments. We have looked at scenarios and identified at-risk capacity, and, again, the key is just to identify those risks ahead of an event.

So, NERC is going to continue to build on their existing framework, and that also includes developing new tools for assessing reliability as the system evolves. And this ultimately includes recognizing that the one size approach just simply does not fit all anymore when it comes to assessing reliability. So we're moving on to more targeted approaches, and that includes unique metrics for specific areas, based on their unique resource mixes. We're also working to better understand the risk associated with having a lot of resources on the distribution side, and it's really important to understand how aggregated impacts of those resources can boil up and potentially impact the bulk power system.

So, as I mentioned earlier, essential reliability services are going to continue to be a major focus for the industry and really helping develop a framework and new tools to assess these different levels of frequency response, voltage support, ramping capabilities, and other measures that can really be critical for reliability.

So, if you think about the system as it's evolving, and there are more distributed resources, the function of the bulk power system (BPS) will also need to rapidly adjust. And in this example you see a system with about 10 percent on the distribution side. There are no major impacts to the BPS. But as it shifts and approaches 30 percent, operators could see some common-mode disruptions, disturbances, and periods of over-generation. And this is going to require additional generation control and dispatch abilities for traditional units, as well as equipment to control local voltages. And, finally, at 50 percent, DERs will ultimately need to act as a system resource. DERs will need to be curtailable. And they will need to be strictly coordinated with bulk power system planning. And that's really going to be the backbone for reliability. Storage is a big piece of this puzzle as well. And, ultimately, operators will need an aggregated function as well to maintain balance on the system.

So, in closing, the North American bulk power system continues to undergo these profound shifts in terms of the resource mix, new technologies, and distributed resources. So it's very important to ensure that appropriate policies and resources are in place for system planners and operators. And, just as we are changing how we're assessing reliability, the reliability standards also need to be appropriately modified in response to these rapid changes on the system. I look forward to the discussion.

Question: We had a big internal discussion in PJM, in preparing the grid resilience comments, as to whether resilience is sort of anchored in and really a part of the NERC reliability standards, or whether it is something wholly apart that FERC could do under its Section 205 just and reasonable rate authority? And I've heard it both ways from people at NERC—either, “We don't do resilience, that's separate,” or, “Yeah, it is part of the reliability authority and standards in some ways.” Can you shed some light on where NERC might be at this point on that very question?

Speaker 2: I think it goes back to the idea that you need to look at each area individually and understand what resilience really means for that specific area. At NERC, internally, we're looking at better defining what resilience is. There are, like I mentioned, existing definitions out there, but we are looking at better understanding what really is needed for resilience, and especially for the future resilience of the system. As the resource mix is changing, there are certain attributes associated with certain types of resources that do provide more resilience under extreme events. Fuel assurance is a big one, of course, for resilience. So, as the system and the resource mix changes, I think that certain things need to remain constant in terms of providing resilience.

Questioner: I don't want to belabor this, but I'm just trying to understand where NERC gets on and off the train in terms of its role in all that. What the thinking is.

Question: On page 12 of your slides, you do not list that NERC is looking at transmission or distribution, which is kind of interesting, and I'm wondering what your authority is to look at it, and if that was just an omission on the slide to pander to the resilience discussion, or whether you're really not looking at it.

Speaker 2: Of course, you have to look at the distribution side and understanding the aggregated impacts, and we have our TPL (transmission planning) standards, of course. Those are reviewed, and there's even an effort to really look at the cost effectiveness of some of the TPL standards. It's really being introduced, probably, in the next couple of years, so. Yeah, that is going to be something we're looking at.

Speaker 3.

Good morning. I last spoke to this group 25 sessions ago, and it's a little depressing how similar my presentation is today. I probably could have used the same one. So, today I'm going to be mainly talking about the resource adequacy angle of reliability. And there's a whole continuum of activities that any utility or an RTO can be involved in with respect to resource adequacy. One extreme is just to do a planning reserve margin (PRM) study and report and tell stakeholders and market participants where things are at, and also have some kind of shortage pricing in place in order to encourage resources when they're needed. The other extreme would involve a mandatory capacity construct, like some regions have now.

So, with respect to the resource adequacy standards and criteria, the commonly used one that we've already discussed today, one day in 10 years (it's usually interpreted as one involuntary curtailment event in a 10-year period), nobody knows where it came from. I've heard people refer to Calabrese 1947 paper. He talks about how to calculate it, but he doesn't throw out a number. I think it might have been found in a cave somewhere. That's kind of what I'm suggesting here. Nobody really knows.

Just to be clear, it is not a NERC or a FERC or any other sort of requirement, although that's commonly claimed. You just have to read the FERC order in RM10-10 to hear FERC say over

and over again that they're not requiring PJM in that instance to actually do anything to accomplish one-in-10, only to do a study.

So, resource adequacy analysis. It's really not that complicated. You characterize your load forecast and uncertainty, your generation resources and their outage rates. You also characterize things like energy-only resources, assistance from neighboring regions, possible appeals to the public in voltage reductions. You put that into a probabilistic model, and out comes what your reserve margin is, your Loss of Load Expectation (LOLE), and your EUE, expected unserved energy. You can calculate all those things, and if you're doing it for the upcoming summer and winter, than really you're just reporting, and there's not a whole lot market participants can do, but there are some things they can do. They can perhaps delay retirement or bring back a mothballed unit, that sort of thing.

When you do the analysis three years forward, you can talk about possible incremental generation that could be built within that timeframe. So, in a three years forward sense, you can calculate a reserve margin, making whatever assumption about what may or may not be built, and also calculate the LOLEs and the EUEs. You can compare that to your one-in-10 standard, and see whether it looks like you're good or not, depending on what gets built. And, of course, in this context, that information is potentially more useful to market participants who probably are also making their own calculations, but they could actually decide to build or to not build, to retire or not to retire, to develop more demand response and such in that timeframe.

And then the next step, of course, would be to take the result of that three year forward resource adequacy analysis and use it to drive a three year forward capacity construct, as done in PJM and in New England in particular. So you have a

capacity construct. You use the results of this analysis to build a capacity demand curve. Nowadays, they're all sloped demand curves. And so, you have your peak load forecast, your probabilistic analysis reserve margin wrapped around a demand curve, and then, through that construct, you acquire commitments to actually accomplish that intended reserve margin.

All that is not particularly economic. It's all about the megawatts and the probabilities. Traditional resource adequacy planning doesn't really get into the dollars very much. So, the economics of resource adequacy are that if you have more capacity, that costs more money to build that capacity, and that will also tend to give you more megawatts in the market, so the energy price will tend to be a little lower. But if you have less capacity, you've got higher energy prices and potentially outage risks. So, that gives you a U shape curve, with overcapacity and under capacity, and the sweet spot is somewhere in the middle. Back in 1978, when Decision Focus Incorporated made this chart, they thought that was a rather flat curve. Of course, back then they had something like seven percent per year load growth in some regions. For a typical summer peaking utility, your reserve margin is driven by your summer peak load, and if you take care of your summer peak load, the rest of the year is going to be fine. You're going to have excess capacity. But in recent times, with increasingly seasonal resources, such as demand response, but also solar and wind can be seasonal, then the LOLE and the capacity value is going to vary by season, and whether the value is more in the summer or more in the winter is going to depend on how your resources match up against your peak loads. And so it is thinkable that you could have regions where you have so much summer resource demand response and solar that the greater value might actually be in the winter.

So, just to point out how much things have changed since back then, you used to have substantial load growth. Now, in some areas, we aren't even seeing load growth at all. New England's latest forecast is actually down. The incremental capacity back then was large and had a long lead time. Now we're looking at natural gas, but also DR and renewables and there's a lot of short lead-time resources that can adjust if we get any kind of surprise on the demand side. So, the "over" risk back then was small. If you built too much, with seven percent load growth it would be absorbed very quickly, so there really wasn't much over-build risk, but now there's much larger risk, because once you get in an excess situation, it's not clear how long it will take for that excess to work down, unless there's a financial requirement. And the "under" risk, back then, of course, was very large. You didn't have price responsive demand, and you had long lead times to build things, so if you got behind on your build, you could get yourself in a lot of trouble very quick. And now, the "under" risk is much smaller, with more price response and manageable peak loads and a lot of short lead-time resources. So, it's a really different situation now than back then, when one-in-10 and things like that were taken so seriously.

I developed this idea in a lot more detail last time I spoke, and I have said this many times, and others have said it many times, but the one day in 10 years standard is very conservative. It doesn't balance. It's not consistent with the economics, as Brattle and others have also showed recently. Any kind of reasonable over/under type of economic analysis suggests a lower target than one day in 10 years. It's roughly two orders of magnitude more than the delivered reliability that we get in the distribution system. So, most customers see a lot more outages through the distribution system than due to resource adequacy. And, in addition, usually the analyses are very conservative and make numerous

conservative assumptions. And with the new considerations we're bringing in now with intermittence and resilience, common mode failures, possible terrorist attack, those things shifted a little bit, but they do not fundamentally change the resource adequacy analysis, in my opinion.

So, why do we impose administrative planning reserve margins on these restructured competitive wholesale markets, as in PJM and New England? The sanctity of the one day in 10 years criterion and expectations in that regard is one reason, but there's always this missing money theory, that because we didn't have elastic demand, price responsive load, and because we didn't have adequate shortage pricing to drive that load, there's missing money in these markets, and the capacity constructs were intended to kind of fill that hole. And that sort of makes resource adequacy a common good, and that's been the main rationale.

So, is resource adequacy still a common good? Can't we continue to question that? I questioned it many years ago, and I continue to raise these issues. Loads are becoming increasingly price responsive. A lot of progress has been made on shortage pricing. There are still some gaps, but even PJM is taking another look at that, and now they are talking about actual shortage pricing, and it could get up to the value of lost load. Of course, with the excess capacity that gets pushed in there by the capacity construct, the frequency with which you might see some pricings is very much in question. But the other observation is that when you do have shortage pricing, if it can push prices all the way up to the value of lost load, then the whole calculation of an involuntary outage rate, a one day in 10 years standard, starts to lose meaning. Because if you go up to VOLL, and you see a lot of customers get off the system, it starts to be kind of meaningless to make a distinction between voluntary and involuntary load

curtailment. And hopefully one day, it will all be price driven, voluntary load curtailment.

For a public service commission, the "thing that goes bump in the night" is, as a result of commission actions or inactions, the lights going out. This is one of the big hurdles to moving these systems towards relying more on prices to balance supply and demand during peak periods. There's an awful lot of conservatism out there. There's an awful lot of risk aversion out there.

In a recent paper for the American Public Power Association, I tried to outline a possible path to phasing out a mandatory capacity construct. It's not something very realistic at this time, because in fact, the RTOs are moving in the opposite direction, and relying more and more on their capacity constructs, with the recent capacity performance and pay for performance type rules. But the first step, obviously, would be to set goals and a vision to have a more efficient wholesale market, a more voluntary wholesale market, and then set a path to evolve toward a more voluntary approach, which could happen both top-down and bottom-up. By top-down I would mean that particular zones or utilities or states could choose to go their own way on resource adequacy, and that would of course require rules and metering and control, and I'm sure that their resource adequacy decisions would not impact other users of the system in a negative manner.

And then bottom-up, of course, is to allow individual consumers more control over their resource adequacy through metering and control. And then you could potentially set a schedule, probably a very long schedule, to transition to a wholly voluntary approach, to give all market participants an opportunity to be prepared for that world. And we would hope that in that world there'd be enough price responsive demand that really involuntary load curtailment would be vanishingly unlikely. During a transition, states

could potentially take a look at one-in-10 and decide whether, to the extent they're still relying on the RTO, they wanted the RTO to do one-in-10 for them, or perhaps something else, and in such a process you might maintain a sort of residual prompt last moment capacity construct for some time, for market participants that rely on that to some extent. And then you'd have reporting requirements for everybody, so that there'd be a lot of transparency about who's planning to do what, when that would guide the market. So, in my presentation four years ago I had four pages of conclusions about capacity markets and such. I'll leave that out. This is just a list of my other work, and I look forward to any clarifying questions and discussion. Thank you.

Speaker 4.

Thank you, and thank you to all have made it here through the bad weather. I thought, given the circumstances, it would be best for me to try to step back a little bit and think about the context of this interaction between economics and markets and efficiency and the reliability story, and try to sketch up both a way to think about that problem, at least the way I think about that problem, and then some of the tasks that are in front of us.

So, one way to think about this problem which is historically accurate in my case, is that NERC sets reliability standards through a "black box," and the black box produces the documents that then govern what all of the RTOs produce. And we are presented with those rules and constraints and ideas and criteria, and then the task, for me and the rest of us, is to say, given those reliability standards, if we treat those as constraints, how can we operate within those constraints in an economically efficient way that's supportive of open access and nondiscrimination and competitive markets and all the other kinds of things that we talk about? And that's not easy, but

it's not that hard, either, and we've been working on that for a long time.

So, an example is that we have a set up constraints that people in the room are quite familiar with, the short hand name is "N-1 contingency constraints." The idea here is that we have a list of contingencies, and if something bad happens, we want to make sure that the system can survive that short period of time, by the laws of physics, that we need to redistribute power across the system, so that it won't cause a cascading back out. So we maintain enough physical reserve capacity and manage the transmission grid and other sources of generation so that the system can adapt over a planning period of minutes, or an hour, or something of that characteristic.

And so these constraints have to be honored, and the way it was interpreted is that these constraints are constraints which limit what you do in the dispatch before the event occurs. This is not how you respond to the event, but this is a constraint on the normal operations, the 98 or 99 percent of the time when nothing bad has happened, in anticipation of protecting yourself from the one percent or one tenth of a percent or whatever that percentage is out there. And so that imposes limitations on what we refer to as "bid-based, security-constrained economic dispatch." Now, if you were coming at this problem as an economist, or you picked up the papers in various IEEE journals or something like that, and you talked about the first-best story about how to do this...and these papers continue to be written. They say, "Well, assume a probability distribution..." So that's the first step, and then we have a probability distribution, and then that produces a series of probabilistic events that are going to happen in the future, and then we should be making our decisions now, so that we maximize the expected benefit across that whole range of probabilistic events, and so on, which is the natural way to formulate the problem if you're

an economist. And if you're an engineer who's operating this system, you have a heart attack. So you say, "We can't possibly do that," because, A, we don't know the probability distribution and so that's a problem, and we'd never agree on what that is anyhow for all these rare contingencies, and so we take the conservative position, which is, we'll act as though the contingencies in this list are going to happen and the contingencies which are not on the list are not going to happen. And then, for the contingencies on the list we will constrain the economic dispatch so it meets those contingencies.

So there's a gap between the economic perspective and the reliability perspective in the way we approach this problem, but what happens historically, and I actually happen to think it's not a bad thing, is that people like me who look at it say, "OK, I'm not having an argument about the contingency list. That's a separate conversation. And whether or not we should be doing expected value maximization or conservative constraint optimization within the constraints that we have, that's a separate conversation. This is what we do, but I want to price what we do. So, I want to make sure that, given those constraints and those reliability rules, we do pricing." And that was the evolution of the model which has now been embraced of LMP pricing and all the other kinds of things that go along with it.

A second problem that arose in that context is we failed in dealing with the economic dispatch story to get all the demand participation that we thought we would get, and we didn't have that scarcity pricing story, and that led to the conversation which is the best illustration, which came from Speaker 1 a few minutes ago, about the Operating Reserve Demand Curve in Texas in trying to do scarcity pricing, and now a similar proposal has been advanced by PJM and they're discussing that, and I think that's a very important thing to do. But, again, it is all operating within

this framework of, we have a black box from NERC and it produces a set of rules, and we take those rules as given, and now we're going to get the prices right to reflect the rules that we actually have, the constraints that we actually have. And that's a good thing. There are still problems that are associated with that, which I'm going to come back to in a moment.

The other question that we're talking about here today is, what's going on inside the black box? Where do these rules come from, and how do they deal with this balance of economics and cost effectiveness, and how can we think about that problem, and what might we do different? And that's a separate question. It's an important question, but it's a separate question.

I did a little research in preparation for this morning. I thank Speaker 3 for his hard work over these years and he's an illustration, as aren't we all, of the fundamental axiom, to make progress in this domain, you need relentless repetition. You have to keep saying this story over and over again. So I'm going to be repetitious. I don't remember exactly when it was, but I was addressing this question of what's going on inside the black box, and I summarized what I concluded, probably 10 years ago, and I said I had downloaded the NERC reliability standards. It was a large PDF file, and I searched for the word "price." So, I was trying to capture where they talked about this economic tradeoff versus reliability standards, and I found, I believe, two or three, I can't remember exactly, two examples where the word "price" appeared when you did a search on "price" through the document. Then I went to the paragraph where "price" appeared, and it said, "We do not consider price [LAUGHTER] when we're setting" And the other paragraph was, "price is not part of the consideration..." So, I did the same test last night. I downloaded the February 15th, 2018 document, which I believe is latest document (and just for

those of you who have nothing else to do on a rainy day, there are 2,303 pages). So, we have this reliability document and I searched on the word “price.” I got three hits. And so, I thought, “Ah, no progress. This is probably the same story that I saw before.” Then I looked under the word “price” and the paragraphs where it occurred. It turns out that there’s a series of three papers where one of the co-authors is a fellow named W. W. Price. [LAUGHTER] The original three references to “we do not consider price” have been removed. So, I guess that’s progress.

So, they don’t talk about it. Now, obviously, I also searched for the words “cost effective,” and that actually occurs once, in the context of setting one of these standards, and they want to do something that’s cost effective.

I have never participated in a NERC standard-setting process. I would be astonished to discover that, in that standard-setting process, cost effectiveness isn’t in the back of their minds, when they’re thinking about doing things, “We’re going to do this, we’re not going to do that.” But there’s nothing explicit about it in any of these rules or any of these characterizations. And I think trying to be explicit about it and think about the tradeoffs here is what you’re hearing from Speaker 3 and what you’re hearing from Speaker 1, and I think it becomes important, as we go forward, to address these reliability requirements, or the resilience requirements, or anything else that’s going along, and then, when we make those decisions, I and others are going to continue to work on the problems of pricing in order to get the prices right within the framework of the rules that have been established.

I frankly don’t think we’re going to get to the economists’ first-best approach to this problem, which is to assume a probability distribution, and then do the stochastic calculation and run the system that way. I think that’s assuming too much in terms of what we know and what we can do

and the problems of dealing with cascading power failures.

So those are two separate problems. I have spent almost all my time working on the problem of, given the reliability standards, what do we do to get the prices right? But opening up the black box and those kind of things that Speaker 3 is talking about, I think, is a critical step, and something that Texas is now giving us the lead on, because they have this record that they produced, and the story that you had heard from Speaker 1, and I think we should have more discussion about that today.

There’s another problem that arises from this that I think is a little more subtle, and I want to call it to your attention so that we can have some discussion about this, which is, we take the black box as given, and then we have the reliability constraints, and then we implement the market design, and then something happens and we’re worried. And then we think we have to fix this. A very common event, I believe, or at least common in prominent cases, is to conclude that, because of the problem that we’ve identified in the market design, like the problem of missing money... So, if you go through the arithmetic about missing money and you take all the assumptions that Joe Bowring and others do in the IMM calculation, they get a big number. This is a big number, and so it’s not a trivial problem, and you can’t just wave your hands and say it’s going to go away. You have to fix something. Shortage pricing is an attempt to try to fix that something, but it’s a serious problem. Another one that has now come up a lot in the last few years is the problem of having resilient or flexible resources that can respond to deal with the intermittency associated with the duck curve and all that kind of problem. And we don’t have that product, we don’t have that market. So people say we need a new product. A “flexi ramp” is the terminology that you hear a lot in the experiments in California. And the product in the case of resource adequacy

and the missing money is capacity markets and forward capacity procurements, and the idea is that we should have capacity.

In both of those cases, I would argue that it's not obvious that there's a missing product. That, in fact, the problem is not that we now have more intermittency and that's changed the fundamentals, or anything like that. The problem is that the actual implementation of the theory of getting the prices right within the framework we actually have has been faulty. We haven't done it quite right. And so, what would be the example? Well, the example in the capacity market case is that we don't do scarcity pricing right and all of that story. And you've heard that from Speaker 1, so I won't repeat that. In the case of the flexi ramp story, I think there's a pretty powerful argument to be made that it has more to do with the implementation of and the management of intertemporal optimization and the pricing over multiple periods, because in a lot of these models we don't do a very good job of that. As a matter of fact, if you read the papers about this, they say that in theory this problem would all be solved if we just did the pricing right over the multiple periods, so we wouldn't have to create new products and new markets, and everything would take care of itself. We could have an argument about that, but the point I'm trying to make here is that, when we take the reliability standards given, and we design a market, and we imperfectly implement the market, it is not obvious that the next logical conclusion is to create new products that we're going to mandate for procurement by RTOs and that kind of thing in order to make up for the mistakes or the problems that we have. My argument would be that you might have to do that, but before you do, you should step back and say, "What is it that is in the market design and implementation that we could fix that would deal with this problem and we wouldn't have to create this proliferation of

other things that don't make any sense from first principles?"

The Operating Reserve Demand Curve is my answer to the resource adequacy scarcity problem. And I think it's attractive for a variety of reasons. Speaker 3 mentioned the pay for performance debate that's going on because of the New England and PJM performance... I'm happy to talk about that later. I won't get into all the issues, but my conclusion from that is that fixing the market design and fixing the pricing and getting the pricing right is just never going to go away. That's still necessary. You still have to deal with it, and all of these other things don't actually avoid those problems. And so, we should be trying to think clearly about what improvements to make within the constraints of reliability, so that we don't have to keep going back and either trying to change the reliability standards or change the products that we're doing. And then we should have this parallel conversation that is suggested by this panel about opening up the black box, so that the next time I download the reliability standards from NERC and I do search through that I get more hits on the word "price." Thank you.

General Discussion.

Moderator: I want to open up by letting Speaker 1 make a couple additional remarks.

Speaker 1: The end of the story was that in late 2016, the end of the year, really, the Commission actually directed ERCOT to junk the 13.75 percent reserve margin that was based on the loss of load expectation--the one-in-10 standard. In exchange, they replaced it, beginning early next year, with publishing, every two years, the economically optimal reserve margin along with the expected equilibrium reserve margin, and then converting it to expected unserved energy. And that will be the target, I'm not even sure you'd call it a reserve margin. It'll be the target

information that is out there, and that will be done every two years. The study's being done now by Brattle, I believe, and I was told the other day that it's expected sometime later this year, in the fall.

Question 1: There are two ways to look at resilience relative to the reliability standards and NERC's role. One argument is that resilience is not a brand new thing that's sort of not anchored to any standard. In fact, it is anchored in the standards. There is a TPL standard that says that you have to plan for a maximum credible event and identify those which could be really significant, like loss of a pipeline, and then have a plan. The standard is kind of weak, but there is a standard. So, one argument is that this whole thing is not like just a basis for freelancing of what everybody conjures up as the risk of the day, but is actually anchored in reliability standards. It doesn't mean we don't go forward as individual regions, but it is an anchor. And that's the standard.

Then there's another argument, though, that says resilience is beyond reliability standards. It's something more for black sky events, that kind of thing, and it's really anchored in FERC's Section 205 authority over just and reasonable rates. Because the question is, are we gold plating the system? Or, are we building out for a credible threat, so that therefore it's reasonable for customers to pay for it? And so that's a just and reasonable rates question, not a reliability standards question.

I'd like to pose that to the panel. On one hand, maybe we don't want to be stuck with the NERC standards as they exist, but, on the other hand, we may be a little bit concerned with this being sort of a free floating concept, where one RTO has one view of what the threat is, another RTO has another view, and everybody's building to their own perceived threat--be it North Korea, be it cyberattack, be it earthquakes--and everybody's

just doing their own thing. But this is a legitimate debate, and I'd like to get people's thoughts on it.

Respondent 1: Sure, I'll comment on that. I think it's very much the first path that it's anchored in the NERC approach. What's changing is that we have more gas-fired generation, so we're noticing that fuel security is a much bigger issue than it used to be, along with common mode failures along a pipeline, so we need to start taking those things into account as we evaluate resource adequacy and all the other NERC reliability standards. And, similarly, we're starting to think that the possibility of deliberate attacks on the grid is something more likely than we used to have in mind inside the black box at NERC, and we should take those more seriously. And I've heard Andy Ott talk about what PJM's doing, which is, "We're looking at our system and we're trying to figure out where the weak spots are that someone who is a little bit knowledgeable could also figure out and go after, and then we're going to figure out how to make those weak spots stronger." And so I definitely agree that it's very much within NERC. It causes a rethink of a lot of the things that have been determined in the past, but it's not a fundamentally new thing. That's my view. Thanks.

Respondent 2: I like the questioner's formulation, and I agree with Respondent 1's answer that, as a descriptive matter, you could certainly, within the NERC framework as I understand it, do exactly what you're talking about. I think your second idea, though, is the conundrum I posed before, which is that, in principle, NERC is not supposed to worry about that. And now they do, because they're human beings. And they're not doing things that are incredibly stupid on purpose. But if you took it to its illogical conclusion, *reductio ad absurdum*, then you'd say, "Well, the first, most important thing about this is that we have to disconnect all the customers so that we don't have to disconnect all the customers. [LAUGHTER]

And then we'd be perfectly reliable in what we were offering." So, I think the problem is that it's not in a situation anymore where it doesn't matter very much. It could be in a situation where it does start to matter and now the just and reasonable question comes up, and that's a normative question about whether or not we should be doing something or not doing and is it just and is it reasonable in the sense of cost effective and is it worth it? From the economist's perspective is it worth the costs? And I think that's outside of NERC's purview. And it's why my little joke about looking for the word "price" in the 2,303 pages and not finding it ever used substantively is consistent with that. That's not what they're thinking about. And I think that this larger resilience question, and particularly some of these proposals to spend a lot of money on it, take us over the line where we do have to think about that, going forward. And that is a completely different paradigm. That is not what we've been doing for the last 20 or 25 years.

Questioner: If I could just summarize, then, what I'm hearing is that you would sort of put it more on the Section 205 side, would least get in that price cost-benefit type thinking that is really not something that's assigned to NERC under the reliability standard?

Respondent 2: Well, I'm going to come from the economic perspective. And 205 and 206 are the same numbers, so I can never figure this out. So, I'd have to ask some lawyer help, but yeah.

Respondent 1: Some of my clients are consumer advocates, and they, of course, are very concerned about what this resilience thing is going to cost. And it's really a conundrum, because, like Respondent 2 suggested, if we're going to spend billions, not millions, we ought to make sure that there's cost-benefit there. But, on the other hand, we don't want the RTO telling us exactly where the weaknesses are in the system

that they are going to fix and what they think the risks are. So it's really a conundrum to make sure this is all sort of reasonably economically justified.

Question 2: I think of resilience as kind of a subset of reliability. So, when you think about the existing standards, obviously they need to evolve as the system is changing, and we should revisit our standards every five years and just understand if what was in the standard then is still going to be applicable today, and then tomorrow as the system changes. So, I think it's just an ongoing discussion, and working with our technical committees as well to identify gaps in the standards where they exist.

Question 3: I used to be on the NERC stakeholder board. When I was on the board, and I was representing generators at the time, the cost of NERC policies, or the cost efficiency, were part of the discussion. They might not have showed up in the end rule, but I can tell you that the whole point of the stakeholder board was to have diverse opinions, and certainly, at least eight or 10 years ago, cost was part of the discussion, even if it wasn't in the ultimate rule. That's just an observation. I don't know if it is true today.

But I have a real question about the black box. Our markets are based on the notion that a megawatt's a megawatt. And there's a very big difference between talking about fuel diversity versus services and requirements that we need to support the grid. Because when you talk about fuel diversity, you're going down the road... "discrimination" is a negative term, but that's really what you're talking about, and that implicates the fact that we clear everything at a single price because we treat it as a megawatt is a megawatt. And I'd be interested in hearing from the panel whether you agree that fuel diversity is a standalone requirement, or is it that we need X, Y, Z services to maintain the grid, and talking

about it in terms of fuel diversity is a bad path to go down? I just think there are very different connotations with the two, and I'm curious as to what you all think. Thank you.

Respondent 1: I agree with your suggestion about diversity. I mean, diversity is something that can be represented in a probabilistic analysis, and a really good case is wind generation. So, if a whole lot of wind generation is in one canyon, then there's a good chance that putting wind generation in a whole different place, that's going to be more valuable, and your probabilistic analysis would pick that up. And, similarly, fuel diversity--you can put that into a probabilistic analysis and quantify it. You typically get a very low number. It's been done sometimes, but I don't think it's a separate thing that has to be sort of exogenously quantified. I think you can actually put it inside the box. Thanks.

Respondent 2: The problem with fuel diversity... because you hear it all the time, and it's used to cover a multitude of sins, I think, is that, at least in our area, but I think elsewhere, the mix is expanding, including on the demand side. And so, when you factor in storage and other kinds of renewables, we have, right now, a diverse fuel mix, at least on the generation side. But in 10 years, I'm not sure we will. It will be gas. It will be nukes, and it will be renewables and maybe storage. And that's what the market is saying that we need. But the other piece that doesn't get enough discussion is the growth of price responsive load on the other side. And all those characteristics, I think, make fuel diversity a little bit of, you know, old Twentieth Century thinking.

Respondent 3: You think about diversity, and I always think of Florida, where they count on upwards of 70 percent natural gas for their peak. We looked at some performance data, and it showed that they've only had, I think, one or two situations where generators were forced out

during that peak hour, and so just because you don't have a lot of fuel diversity in a given area doesn't mean you're not going to be reliable. So I think it's important to separate the two. But, ultimately, I think about a lot of wind and solar coming on. They all have to support the system reliability at the end of the day. I think that's what NERC's really focused on.

Respondent 4: I mean, the short answer is that if you get the prices right within that second framework, the framework I've talked about...if you take all the constraints, and you design the market well, and you get the prices right, then the argument has to be that there's a public good that's not captured in the prices and it comes from fuel diversity, which I don't think is illogical as a matter of principle. But it's not obvious to me that it's also true. So, getting the prices right is a much bigger problem, and that's what we should be doing.

And when you start thinking about it, if you had adequate scarcity pricing, and you had demand participation, and you have all these different sources of variability and adjustment, it's not obvious to me that you need anything more than that. And I can't rule it out as a matter of principle, but I don't think that's the right focus on the problem, and I think it's a response to the fact that the prices aren't good enough yet, and so we're going to have to create another product, which is fuel diversity, "I want to buy 12 fuel diversities, please." And I think it's mostly just as Speaker 1 said, covering up other sins. And so, I would focus on the other sins.

Question 4: I want to go back to something Speaker 1 talked about when he was talking about whether a capacity market or a one day in ten standard would have been helpful in Texas. He talked about two events. One was a spring event where the temperature was really high, and then he talked about the cold snap in 2011. And I

wondered whether, because those wouldn't have been caught by something like a one day in 10 standard or capacity market construct, those examples suggested that we're missing something in those constructs, and whether that something falls under the umbrella of resilience. So, are those examples of unique Black Swan events that you didn't plan for and you wouldn't have planned for in a capacity market, but maybe something that for people that do have a capacity market, they should start to think about and broaden the perspective of the capacity market to include that?

Respondent 1: Well, I think the mistake is trying to achieve in the capacity market the results that come naturally in the energy market if you have proper scarcity pricing. One of the facts I didn't mention was that the summer of 2011 was an extraordinarily hot summer, one of the hottest on record in Texas. And although we never went into a blackout, there were some EEA (Energy Emergency Alert) events. Prices got high. And you had some load serving entities that lost a lot of money, because they thought they were fully hedged, but it turned out they weren't, and on a couple of days they lost a lot of money having to cover costs in the real time market. That drives a lot of behavior that I think is beneficial.

If you try to replicate that in the capacity market, what you're telling your loads is, "Well, you're buying that insurance in the capacity market, so you don't have to do anything." Yet you still have those events, whether it's super heat or super cold or some other Black Swan event. So, I mean, that's the answer. If you treat your loads as grownups, and they have to manage that risk, at least based on our experience in Texas, they do, and they are. Because it's not just avoiding the downside, they also have an opportunity to make a lot of money. There were some large industrial customers in February, 2011. They had to back Mack trucks up, they were making so much

money. They reduced their consumption. They turned on their backup generation. They were selling it into the market for four, five, six, seven hours at 3,000 bucks. So, it's not just avoiding the downside. There's upside in the market as well that encourages that behavior, or can.

Respondent 2: I would just add that one way to interpret one day in 10 years is that we're ready for very extreme events, or combinations of very extreme events, but we're not ready for Black Swan events. And that's the one day in 10 years, and if you play around with these probabilistic models you find that sometimes, when you make some of the real extreme tails of the distribution even worse, it doesn't really change the result, because the models already saying, nope. I'm not ready for that. I'm ready for almost everything, but not that.

Respondent 3: Just one more quick point on that. NERC puts out long term and seasonal assessments. Obviously, they include ERCOT and all the other areas in North America. And I kind of see the amount of planning reserves that a system has as a piece of resilience. When you think about it, in ERCOT they were at 23 and a half percent reserves last year and then they dropped to 18.6. Now they're at 9.3 going into the season. For NERC assessments, it's concerning when things are fluctuating that rapidly. How do you get ahead of those fluctuations, and how do you identify those at risk retirements. ERCOT is an energy-only market. SPP is the only other energy-only market, and it's just a matter of longevity and how you're going to have those resources procured and guaranteed in the long term. And so, we just noticed a lot of fluctuation in the last five, six years.

Respondent 1: By the end of the year ERCOT expects over 900 megawatts of new utility-scale solar that will drive up the reserve margin, along with some more wind and other things along the

coast. I will concede that you're going to see a lot of volatility, but, again, that's not a bad thing. I know that in the utility business, at least in most parts of the country, there's an attitude of, "Oh, volatility, it's a bad thing." Actually it's a good thing. It drives the right behavior. At least that's what we've experienced. Now, maybe we have a particularly good legislature that's been trained to expect it, but every time there's a sky falling, it turns out that if you are properly hedged, you ride through it.

Respondent 4: So, the reliability is ultimately measured by a good legislature?

Respondent 1: That's a frightening thought, but, you know...

Question 5: I get the point. If we can get the prices right, a lot of other things should follow and be corrected. And I'm trying to figure out, well, what really is the price? How do we get there? We struggled with this when we put in pay for performance in New England ISO. Our external market monitor, David Patton, felt that we were pricing it far too high. And I guess a lot of economists would feel that. But one of the things that goes through my mind is, how do you really know if such volatility, in the view of a consumer, is what the right price is? What they're willing to withstand for a couple of hours during a spring day is vastly different than what they're willing to withstand in the middle of the night in a cold winter, especially if the outage goes more hours, and their house really gets cold. And their own views about that change, so if you ask them what would be their price point at a time when they have power, they might come back and say, "Well it's not very high if I lose it," but, on the other hand, if you ask them in the middle of that night on a cold day, they're going to say that it's extremely high. So one aspect of my question is how, when you do your thinking as an economist, how you come to a conclusion about that.

The other part of my question is really about how much you get the generators to internalize the infrastructure system that they have to cope with. And this obviously has been a real big dilemma for New England, and one of the things we observed is that you just leave aside all the political and environmental concerns while putting in stronger gas infrastructure. There's no incentive for individual generators to do much. They are not going to, on their own, sign up for reservation fees for incremental amounts of additional pipe if in doing so they feel that they'll never get a return, but everybody else will be a free rider. So there's not an easy construct economically to encourage that kind of broadly based social infrastructure improvements. And meanwhile, as we found in this past winter with a real cold snap, the other parts of the infrastructure system for short term delivery are very fragile. And so even if you had a very sharp price spike on a given day late in January, it does not mean that the fuel trucks coming up from Delaware can make it. It depends upon the road conditions. It depends on other demands they have that are obligatory for home heating, and the price response may not be adequate almost no matter how high it is. So I don't have an answer for all that, but I just wanted to sort of throw those out there as really a very difficult issue for us to be grappling with, when we talk about a pure price spike or price point answer to how we could maintain the reliability that we wish to happen at grid.

Respondent 1: Well, those are all good questions. The first one is about how the value of lost load on a nice balmy spring day is quite different than the value of lost load in the middle of winter, if you're using electricity to heat your house or run the systems. That seems obviously true, and I guess the implication, which at least I haven't discussed very much, would be to try to estimate the seasonal warmer weather or contingent values

of lost load in defining what is the equivalent to the Operating Reserve Demand Curve. And I don't think that that's a bad idea. I'll think more about it.

Questioner: If I could just interject, though. Even in the middle of winter, losing power for one hour may not be a big deal. Losing power for 10 hours is a huge deal, so that cost has to be factored.

Respondent 1: Right. And that's related, but a slightly different issue. But all of those would need different evaluations, depending on what you think is happening. And then what was the second part?

Questioner: Looking at what would be the right price point for a pay for performance penalty.

Respondent 1: Well, pay for performance presents another set of problems. The fundamental problem with the pay for performance design is that it has been carefully constructed so that it's half the market. In other words, it's nets out to zero amongst the generators and it's been designed in such a way that it doesn't affect the price that goes to the load. And that's a mistake, in my view. That's not a good idea. It's part of this idea that we can't have the volatility story. So in principle you could get a situations in PJM and New England where the price for some generators will be effectively paying them \$5,000 a megawatt hour for their generation, and the load across the street will be charged \$200 a megawatt hour, because that's the market clearing price in that situation, and that can't make sense, OK?

So, if it doesn't make sense, what's the answer? Well, the answer is the Operating Reserve Demand Curve, and you affect load and generation in the same way. And then it gets back to your first question which is, what happens if you underestimate the value of lost load, which is

effectively what we're doing now, saying it's very, very low. Well, that's a bad idea. What happens if you over estimate the value of lost load in this process? Well, I'd rather have a good estimate than a bad one, but if I err on the high side, I've still got the possibility that the demand participation now has a very strong incentive to enter to do just the kinds of things that Speaker 1 talks about, in which case the Operating Reserve Demand Curve pricing becomes much less important, because it gets driven entirely by the voluntary participation on the load side, and you don't have to worry about this as much. So that would bias me in the direction of having a higher rather than a lower value of lost load, just to make sure that you create that incentive, and it's there, and we get the demand participation in it. So I would fix the New England and PJM systems by getting rid of the pay for performance stuff. I'd have an Operating Reserve Demand Curve, which is supposed to provide the same incentive, but to do it so that it affects loads as well as it affects generation.

Question 6: With regard to reliability standards, I've had the unique opportunity to serve on a NERC standards drafting team. And I have to tell everybody, you have not had fun until you sat in a room with a bunch of lawyers and engineers and drafted a standard by committee. There's nothing like it. But the point I'd like to make is that while the previous commenter is right, price was always in the back of a lot of people's minds, there wasn't an official policy that I was aware of, from NERC's perspective, on whether or not to take price and cost into consideration. So, my question is, is there an effort at NERC to take price into consideration, and do you think that it should be taken into consideration?

Respondent 1: It's kind of ironic, because my background is all economics, and here I am, most of the time, surrounded by a lot of engineers and looking at NERC's purview, and, when you look

at it and you read the standards, it just doesn't really focus on price. There is an effort underway that's going to look at the cost effectiveness of some standards starting with the TPL standards. So, that is something that's underway. I'm not sure about the exact timeline, but there will be a cost-benefit kind of analysis that's going to be done, going forward, on our standards, and I think that's probably necessary.

Respondent 2: Just for a follow up to that, talking about the history of NERC, one of the things that's interesting is the you still have the Regional Reliability Councils, but some of them have sort of evolved or at least operate in parallel to the ISOs, which also have reliability requirements as well as economics. So, I'm wondering if the existence of ISOs, their evolution over time, has changed the dynamics within NERC at all in terms of how they look at these things.

Respondent 1: Absolutely. I mean substantially, I came on in 2011, and they just switched to assessment areas which were based on the ISO/RTO existing footprints. And those have changed over the years, but the way we used to collect and present our assessment data on a regional basis just didn't make sense, because that's not how the system is planned and operated. So, as that's happened, we have more and more stakeholders and subject matter experts on our committees and stakeholder groups from the ISO/RTOs that are certainly involved in the market, and their questions are always, how can you ignore the market structures? And so, we're doing more of that in our assessments, at least trying to better represent and explain the market impacts on the reference margin levels. We came up with this term reference margin level and that seems to be sticking, but, again, we can't ignore obviously, the market structures in our reports. And so, it's continuing to shift in that direction.

Question 7: I have a question about adapting reliability practices to technology change. Specifically in the context of bridging the gap between bulk system and distribution system reliability. So, Speaker 3 had a really interesting slide where he was showing that flexible resources in DR have essentially changed resource adequacy in terms of overbuilding and underbuilding, kind of showing that reserve margins are increasingly, call it obsolete...and if you think about most outages being in the distribution system, and that an increasing amount of capacity is being built distributed, I look at, for example, NERC treating distributed resources and as a result also the ISOs treating them as a problem, to be contained, and distribution reliability basically being tree trimming and equipment replacement, when we have technologies that just a few years ago were considered science fiction. Things like feeder topology configuration for autonomous islanding and voltage management and new types of distributed energy resources. So, in that context, how do we bridge this gap between talking about the details of bulk system reliability and market design and all of that when there's so much change happening already in the distribution system--and that's where the reliability problem really is, right? That's where most of the outages are. And we're not really talking about that in these discussions. So, is it a jurisdictional problem? Do we need better modeling? Like, what is it?

Respondent 1: NERC's purview ends at the end of the bulk power system and bulk electric system. We defined that recently as one hundred KV, and of course there are exceptions and inclusion in situations that go outside of that, but, thinking about our reliability standards, that's where, of course, they stop. At that point, it is up to the distribution providers. We're more concerned about what's being placed on the distribution side that has aggregated impacts on

the bulk power system. So, that's where the ERS (Essential Reliability Services) comes in. I'll give you an example, the load forecasting that we put in our assessments. A lot of that has DERs built into the load forecast, and it just reduces the load. Well, how do you capture that and isolate it and assess it, because there is a potential for those resources not to show up behind the meter, and then, of course, the bulk power system generators have to cover that gap? So really what NERC is focused on is really understanding how this is all going to work, especially going forward.

Questioner: Just a little bit more context, the one-in-10 standard implies a value of lost load of what, \$100,000 a megawatt hour? So we're drastically overbuilding the system. When we have high reserve margins, we end up devaluing new types of resources that could come in and perform the service better, in some instances, and much more cheaply. And because we're putting so many resources in the bulk system, it ends up kind of taking away from modernizing distribution systems, in a sense. Like, the dollar amounts just don't really mesh together. So, is it that NERC needs to have a broader jurisdiction to look at reliability more holistically?

Respondent 2: One of the things that the 2012 Brattle report really brought to my attention (we knew it intuitively, but you didn't think about it, even as a regulator), was the fact that all this focus, with reserve margins and other reliability standards, is about the transmission system, when, again, at least in Texas, the outages on the distribution system, if for no other reason than bad storms, are astronomically in excess of the worst nightmare for having a problem, a localized problem or a capacity problem, with the transmission system. And yet there's not much that's ever done about it and you got the SAIDI (System Average Interruption Duration Index) and safety standards, those things, but that's really...I don't want to call it a joke, but it's sort

of a joke at the Commission, with the annual findings that role through, and it turns out it's always a feeder somewhere out in the middle of nowhere where there's three ranch houses on it. You've got to have a Humvee to get out to the tail end-type stuff. Yet, you don't really hear a lot of complaints, except maybe in the second or third week that you're still out, because that doesn't happen. The local utilities, they get on it. They're investing in resiliency, in technology, but the economic costs on that system...and part of it is because the larger customers who absolutely have to have reliability, they took care of themselves a long time ago. If you're a big box store that also has refrigerated warehouses, or if you just have refrigerated warehouses, you put in backup generation. Why? Because you're going to have a thunderstorm in North Texas that's going to knock out the distribution system for some period of time. That's how people have accommodated. My lights go out, I go home and there's been a storm and my lights are out, or just, in the summer, a transformer blows on the distribution system, and your lights go out. You live with it, and not much has really been done to focus on it.

Questioner: Do we account for the backup generation in the resource adequacy calculations, for instance? Does NERC think about these critical loads that have a very high value of lost load already having their own backup generation?

Respondent 1: We collect data on it for our assessments. We look at standby load under contract as well. We look at those impacts. But, again, they're not explicitly covered in the standards. We don't go down into that distribution system.

Question 8: I want to return to the point that had been made earlier about this linkage between getting the prices right and diversity of power supply and resilience. And I think that everybody kind of agrees with the idea that if we have

competitive markets that force people to compete on short run marginal costs in the market, that we'll get an efficient result. And if you look at cost and performance, we're going to end up with a diverse mix of fuels and technologies in an efficient market result. And so I think we're right in saying that if we get the prices right and (as I've heard Speaker 1 mention) give people these price signals, "Look, you can only make money if you're available on the market," people are going to do cost-effective resilience investments at their individual plants.

And if an efficient market gives you a diverse set of fuels and technologies, you get inherent resilience, because if you've got a cost-effective mix with expected conditions, and you introduce uncertainty, the risk factors in a diverse set of fuels and technologies don't have high correlation. In particular, nuclear power plants don't have correlations with the risk factors for gas plants.

When we look at our markets today, we're not getting the prices right. Look at PJM. We don't have a level playing field with cost competition. We've got some generators in PJM who don't reflect costs in their short run marginal cost, because subsidies have shifted cost away. In PJM we have some states where rival generators are internalizing some CO2 costs, and competing against generators that do not internalize the CO2 charge. So we don't have a level playing field. We have competition that is not counting all the costs, so we're not getting an efficient result. And, in particular, if you look at these distortions, they disproportionately reduce the cash flows to non-CO2-emitting, high-utilization resources in the market. And those are nuclear plants. And so, if we allow these distortions to continue to play out, we will get closures of power plants that are cheaper to keep running than they are to replace, and we'll get a loss of the inherent resilience you

get from an efficient market outcome, and we can just sit by and let that happen.

There seems to be a consensus that there are lots of defects in pricing, and we can just let them play out, or we're in this second best position of having to compensate with things like flexibility payments or ZEC payments. And part of that is to preserve the inherent resilience that we've got. If we lose it, it means the marginal cost of reliability's going up, so if we do balance marginal cost and benefits of reliability, these market distortions will lead to a lower level of reliability, even if we're doing it right.

Respondent 1: You combined a couple things in there, resilience and CO2, and I guess I would agree with you about CO2. Some low-CO2 resources are getting some kind of subsidy and others aren't, and that's obviously an un-level playing field, and it's better to put CO2 in the price, and maybe we'll get there someday, but there can be a case for bridging zero-CO2 resources in the meanwhile.

Respondent 2: And there was a Machiavellian argument, which was a refreshing way of looking at the problem that brings in many, many different dimensions that I hadn't thought about before, so that's a good thing. The one thing about it that I'd want to think more about is, if you look at the PJM last week, Joe Bowring, the Market Monitor, produced his report, and basically he said that there aren't very many nuclear plants that are at risk, really. They're not making as much money as they would like to, but there aren't very many that are completely underwater, given short run costs. I think that's an example of a point, which is, when you start doing these subsidies, that has an effect, but then there's going to be an impact, and then if you start losing some of those plants, then that's going to raise prices, and so there's an equilibrium along the way. You don't lose them all overnight because

of something like that, and so I think the equilibrium story is going to be quite a bit different, and that's why I am skeptical, frankly.

I mean, subsidies always create problems and unintended consequences. So, that's a problem, but I'm skeptical, personally, that if you did a better job of getting the prices to reflect what you have within the rules that you have, even with the subsidies that you have, that you would end up in a situation where the equilibrium solution would leave a large public good that's not addressed, which is fuel diversity. And I remain to be convinced that that would be true. I can't rule it out as a matter of logic, but I think with respect to getting the prices right, part of the problem is going to be a lot of complicated adjustment. Some plants are going to go away, others are going to come along. That's what's been happening in Texas. Some plants are going away and others are coming along. And you'll get a new kind of equilibrium

Respondent 1: More than nine years ago, probably, I read a story about the situation in New England and parts of the Northeast. I keep coming back to it, since New England's situation is sort of an infrastructure problem, really, isn't it? And if you don't build what you need to build, that's an externality imposed on the market that I don't know what you do about. You can't build transmission to bring hydro power down from Quebec. You can't build gas pipelines, and the motivation, besides NIMBY, is really about fossil fuels. But it's not. It's about infrastructure. Nobody wants the infrastructure. Maybe we're just blessed in Texas that the State bird is the building crane.

So, I don't know what you do about a market in that context. Ultimately, the price will go up to the point where folks say, "Well, maybe we do need the infrastructure." I don't know, though, because a lot of the opponents in those cases are

not worried about either price or blackouts. And that then becomes just a question of political will, and you can't do anything about stupid. [LAUGHTER]

Question 9: As many in this room probably already know, the powers that be in Alberta have decided to introduce a capacity market construct into our jurisdiction. We don't have a lot of time to implement it, from a technical perspective, but we are going to be going down a road of modeling resource adequacy. The government has determined a minimum threshold for reliability set at 0.0011 percent normalized expected unserved energy. We do intend to also have a downward-sloping demand curve for capacity, as well, to help reflect that it's not just a physical standard, necessarily, but to try to recognize some of those economic impacts.

My basic question is sort of a practical one to the panel. Given where we're at, especially with what I just said here, what would you suggest Alberta do in terms of trying to avoid a lot of the pitfalls or challenges that you've identified with a lot of the conventional resource adequacy modeling and all that goes with that? What would you recommend Alberta do to try to get it right, for lack of a better term?

Respondent 1: I think using the normalized expected unserved energy is a good start. Because at least you've got to decide what that is, and apparently the government has decided that, but at least it's based on an assessment, on a magnitude and duration you're willing to tolerate, or that you want to seek to avoid. And so I commend you for that. My problem with reliability standards, in particular with the one-in-10, is because it just made no sense, and I couldn't figure out where it came from. My policy advisor, when he dug into it, found references in the 1930's, I think, in an article by a

professor who said he didn't know where it came from.

Respondent 2: Hopefully a lot of the things that were big problems and issues early on in New England and PJM won't afflict you. In those early years, the capacity offer supply curves were really steep, so things like the reserve margin and the load forecast and everything else made a lot of difference. So, all of a sudden the stakeholder groups working on the load forecast were all different, and we fought over that, and the stakeholder groups working on their reserve requirement...all of a sudden that got to be contentious. But over time in PJM, the supply curves are a lot flatter, so a lot of those things don't cause quite as much struggling. But constantly every little bit of the rule, every parameter (because there's billions of dollars hanging on it) are carefully worked on by stakeholders, time and time again.

So, I don't know what the supply and demand looks like. We spoke about this a little bit, but hopefully you'll start it off small, so that it's not huge dollars right away, and I would really encourage you to work hard on the original vision in PJM, and then the other capacity constructs, which was that they should wither away over time, as we increasingly get the prices right and have enough price-responsive demand on the system and good strong shortage pricing, so that there wasn't any missing money, and the capacity construct, hopefully, would become unimportant, and the prices would sort of wither away. I hope that you kind of got that goal in mind, because what we saw in PJM is that it's a constant struggle to try to get prices higher, and in PJM we did about a dozen things over the last six or eight years trying to get the prices higher. We shifted the demand curve. We chased out imports. We imposed the minimum offer prices. We squeezed down on demand response. We raised the net CONE. We relaxed the supplier market power

mitigation. We increased performance requirements, and there were four more things. I can't remember. But, for the most part, it was ineffective only because of the shale revolution. And there's just people out there willing to build combined cycle for \$100 a megawatt day. So, I don't know. Hopefully, that's a little helpful to you.

Respondent 1: And in the real problem in that case with the mandatory capacity construct is that you're basic manipulating the energy market, because you're bringing in resources that by definition depress your prices in the energy market, thus encouraging the behind the load side to be lazy.

Respondent 2: Thanks for reminding me. I mean, all those things I mentioned that we were hoping would get capacity prices up, they didn't, because folks are willing to build combined cycles. So what's the result? A very consistent four percent reserve margin beyond the very conservative one-day-in-10 reserve margin year after year after year, and of course that means that you've got this excess in the energy market, and prices are generally low, and you've got lot of PJM utilities who sold their state regulator on demand response and advanced metering and all that by saying that it was all going to be valuable, and that value isn't being realized because of excess capacity.

Respondent 3: Well, if you don't have a capacity market you need an Operating Reserve Demand Curve like they have in Texas, so they don't have to deal with scarcity pricing. If you do have a capacity market, you need an Operating Reserve Demand Curve like they have in Texas in order to deal with scarcity pricing when the situations actually develop. These are not either/or choices, and the long debate over the need for pay for performance penalties under capacity markets in order to give people incentives to actually show

up in real time is *prima facie* evidence that that's a big problem when you don't have those incentives. You're going to have to have those incentives. And you might as well do it in a way that's neutral with respect to supply and demand side, so you get all the demand side things that we talked about before. So, refraining from the temptation to offer a lot of other suggestions (you asked for the most important thing to do), I would implement a Texas-style Operating Reserve Demand Curve and the pricing models. Get rid of the capacity and the limits on prices in Alberta, and you'll be happy you did it when you get into a tough situation, and resource adequacy won't help you if you get into a tough situation.

Question 10: I think there's general agreement that having higher compensation in some form, whether it be operating reserve prices or pay for performance for delivering energy, is key to performance and reliability, particularly on the resource side. One thing I hear occasionally (and this gets to any time there's a reliance on prices to achieve a given policy outcome) is that, in particular where there's kind of a quantum change in the kind of performance you're looking for, or there's a potential risk, in that we're not sure if those getting the signal are actually going to do what we expect--and particularly in the context of a low-probability event.. I've heard the phrase, "Black Swans." I'm not quite sure any of these events are actually true Black Swans, because I think the risks of cold during the winter are foreseen. I think they may have known their machines aren't going to operate. They don't recognize the cascading correlated effects that happen when everyone's machines don't operate.

But is there any learning that has happened from Texas or another context that can potentially either move the market in a way such that the operators are kind of getting a signal about mitigating the kinds of operational concerns that they need to mitigate, or, more importantly, such

that stakeholders can kind of wrap their heads around the fact that these signals will work? Because it often feels like a chicken and egg problem. Some people feel that the operators aren't going to do anything until they get that first cold snap and suddenly realize, "Oh, we can make a lot of money." The same thing happened with the polar vortex. Suddenly prices were 100 bucks, and there was some money to be made.

But there's that lingering concern among many people in the community making these rules that we can't quite rely on people responding, particularly for these very, very low probability events, particularly when you have to put your money on the table up front. And in some cases, putting storage at the beginning of the year for fuel, you need to put some money upfront in order to mitigate a risk. And so it becomes a hedging issue, but an operational hedging one. And so, I'm just wondering if people's experience in Texas or other locations can provide some insight, in terms of how we can encourage people to have some faith in that approach working.

Respondent 1: One of the therapeutic benefits of the February, 2011, event was actually on the thermal side, because a lot of generators who had real-time commitments, whether it was because of their bilateral contracts or a day-ahead position or both, lost a lot of money. And even those that might not have had that risk also lost a lot of money in terms of lost opportunity. What we've seen since then is that the operational reliability of the thermal fleet has improved dramatically. The forced outage rate in the summer in ERCOT is always historically been lower in the summer than anytime else. Why? Because the fleet gets ready for the summer in Texas, which is going to be hot, or it's going to be damn hot. [LAUGHTER] And so, we see that.

On the load side, at the very end of the resource adequacy debate, I had some representatives of

two very large big box chains who came in, and they had been a little bit missing in all the debates about a mandatory reserve margin. They came in and said, “You know, commissioner, you’ve got to stop this, because we’re on the distribution system, and we need 100 percent reliability, and we’ve invested in backup generation. We now realize, having invested more money to actually be able to participate in the market, that if we get this capacity market, not only will we have to pay this non-hedgeable, non-bypassable charge, but we’ll lose all the opportunity to make money when these events occur.”

Now, if you’re a business like that, you’re going to respond. Why? Because if you’re a manager, or whoever’s running that part of the business, if you don’t respond, you’re going to get fired. The same thing happened to the generators in February, 2011. There were plant managers who lost their jobs, because they weren’t ready. Now, I know that in a lot of parts of the country you want some kind of command and control mechanism to do that. All I can tell you is, if the proper incentive is there on businesses, whether generation or load, they’re going to respond, because it makes a lot of economic sense to do so.

Question 11: Going back to something that Speaker 4 brought up earlier, with a description of what he thought were two examples of flawed new products, capacity markets and flexi ramp products, it seems like there is a tension between wanting to position the system and your resources so that you’re sort of capable of responding to what are foreseeable needs—so you can look out and think, “OK, this is coming. I want to posture my system. I want to pre-position it,” versus a little more hands-off approach of just kind of relying on and allowing higher prices and responsive resources just to sort of have everything work out--and I don’t mean that in a bad way. But I just wonder, is the conversation that we’re having here, from an economist’s

perspective, do we wish that our system operators were a little less interested in sort of pre-positioning and posturing, so that we would get to those higher price instances either more frequently, or we would be more comfortable with them?

Or is the conversation about something different? That is, we’re not talking about what’s foreseeable; we’re talking about, really, when you get into a bad situation that really was unforeseeable, then this is just sort of a better regime, potentially, than the one-in-ten regime, with all this perhaps excessive concern about resource adequacy.

Respondent 1: I’m not sure I know the answer. I’ll have to think about your question. It’s hard to ask the system operators to protect us against unforeseeable events, because they can’t foresee them either. And so I think we’d have to separate that component. But if you put it in the context of uncertainty, we’re doing a certain set of things. We have the expected load that we think is going to happen over the next interval or a period of time. But it might be higher or it might be lower. And how do we deal with that? That’s a little bit of a harder problem, and that’s one of the reasons we have things like operating reserves and such things as that.

In a lot of these regimes we have shortage pricing, if we have a shortage. So, what does that mean? That means the system operator has to declare that there’s a shortage. And then, when they declare there’s a shortage, there’s a mechanism for calculating something that’s a higher price for that. This puts the system operator, a human being who has to make this decision, in a difficult position, because they have an institutional and human bias which is not to declare a shortage and not to let prices go up, so they don’t get the phone calls and they don’t get people hassling them. One of the advantages (and it’s not accidental) of

the Texas implementation of the Operating Reserve Demand Curve is that the system operator doesn't have to make a decision about whether there's a shortage, and that's because it's an anticipatory story with expected values and probabilities, and it applies, in principle, all the time. And sometimes the numbers are small, and, as a practical matter, they truncate to zero, but you don't have the operator having a meeting every five minutes and saying, "Should we invoke the Operating Reserve Demand Curve or not?" (They were all down the hall in a meeting about, "Should we have a Reliability Out of Market commitment decision?" That's another problem.) But they don't have this problem of taking on the responsibility of deciding whether or not they're supposed to raise the prices. And I think the more you can institutionalize it and make it reflect the automatic conditions in the market...as opposed to unusual situations that were not anticipated, and now they have to do something, and that's what you're going to rely on...

I think you're better off doing it the way they're doing it in Texas, in principle, than following the notion that somehow there's going to be a new ethic in the system operators to deal with unforeseen events in a way that is going to give you the same kind of incentives, so. For example, you could implement the Operating Reserve Demand Curve in a completely different way, which is that if you get into a situation where you have for example, the wind all going away in an hour, now you're going to have the prices go up to really high numbers during those rare periods of time. And then people should anticipate that, and then they should calculate the expected value of that, and then they should hold back their reserves and not sell them to the system operator, because they're waiting to get the reserves, because they're going to get the value. So, you could have another kind of market approach to that kind of problem. I just think that's a much

harder thing to rely on and implement, as opposed to having the Operating Reserve Demand Curve which defines the expected value of that price, and that's what we pay you now, rather than paying you for having those reserves available during all these periods of time. And I think that's the way it's done in Texas, and I think that is a better way to do it, and it seems to be working. So far it's having the effect as anticipated and expected, given the capacity situation. Dealing with Black Swans and unforeseen events is a harder problem.

Respondent 2: At least in the past, the theory was that you can address this Black Swan situation if you have a lot of reserves on the system. Excess capacity is going to cost money, and NERC's focus is solely on reliability. So, you think about the markets and proactive versus reactive measures. A lot of the market mechanisms that have been put in place happen after an event. For example, the polar vortex. You identify the risk, and you introduce mechanisms to address those risks in the future. That's a reactionary situation. In Texas, in 2011, a lot of the wellheads froze up. You had a lot of units that weren't, perhaps, prepared for the winter in terms of weatherization. So, after that, you had a lot of winter weatherization preparation going into place.

So, those are sort of lessons learned. You respond accordingly. In Texas, you had seven or so units that were retired in a very rapid timeframe. The requirement for notice to ERCOT used to be 90 days. Now they upped it to 150 days. So, I think NERC, in its role, tries to identify these risks ahead of time. It's easy, when you're just focused on reliability, obviously, not to think about the price impacts and implications, but, again, just as with our risk-informed standards, we want to make sure our standards are addressing potential risks and they're adjusting and adapting to reflect those risks, so that we're not going back after

something major happens and having to respond. I think being proactive is critical.

Respondent 3: And keep in mind that with respect to daily operations, the operators still have the tools in the toolbox, like “Reliability Must Run” (RMR) and “Reliability Unit Committed” (RUC) generation. What you have to do in that case is to tweak your scarcity pricing mechanism, in our case, the Operating Reserve Demand Curve, to make sure that the price impact in that case, if it results in deploying out of market or taking the out of market action, gets reflected. I noticed that just, I think in the first open meeting of this month the commission is backing out. They voted to back out both RMRs and RUCs from the reserve calculation, which will have the effect of increasing prices at the same time, but the operator will still be able to have those tools in order to meet the contingencies that happen in a particular area. We also have (I think it’s still there) the ability to RMR all units for capacity, but if that happens, then the price goes to the cap as long as those units are on.

Question 12: One statement. Everybody’s blaming market rules for not getting enough revenues, and Speaker 4 alluded to this, but there’s still a lot of operator actions that impact the markets, actions that are not priced and that are not transparent. So, if you’re going to complain about what’s not giving adequate revenues, I throw that one in there, too.

My question goes back to the original purpose of this. In listening to everybody talk about the mythic LOLE, how much of our reliability assumptions are based on what the generation fleet looked like 40 years ago, which was nuclear and coal serving baseload? And it also goes a little bit to Speaker 4. You talked about looking at things with more seasonality in response to the question of New England. How much of that is

still driving things, and is that something that we need to reconsider going forward?

Respondent 1: Well, looking at the one-in-10 standard and how it relates to the reference margin levels for various areas in the country, NERC recognizes that it’s no longer adequate, when projecting resource adequacy and reliability. And that’s why we’re looking beyond it. We’re doing more targeted, probabilistic analysis. We’re focused on ERS (essential reliability services) measures, as I mentioned, and those are still in development, and we’re identifying the appropriate threshold--where you look at a given area, like perhaps California. You recognize the ramping concerns there. Well, that’s an example, and you can establish some lessons learned from that situation, and then those can be applicable to other areas of the country as those areas change. So, that’s where we’re heading. We fully recognize (and there’s been a discussion for some time) that the reserve margins—that deterministic approach is not enough to fully capture the reliability of this system going into the future. So, we’re looking beyond it, for sure.

Respondent 2: Yeah, I would just add that as the resource mix changes, that flows through your resource adequacy analysis and changes the reserve margins. So, if you apply one-in-10, you’re going to find that reserve margin will change and will pick up a changing resource mix.

Respondent 1: Absolutely, but it’s a question of, is it responding quickly enough? And there are other studies done, not only on the existing resource mix, but on who’s coming in way down the line.

Questioner: My question goes a little bit to the fact that it’s this piece that drives the IRM (Installed Reserve Margin), and the IRM is based

on the fact that we used to have nuclear and coal baseload facilities.

Respondent 2: Well, PJM, and I guess others, too, in their resource adequacy analysis they anticipate what the fuel mix is going to be, say, three years in the future. And that runs through the model and influences the reserve margin to meet one-in-10. So I think that is largely captured.

Questioner: How does it do that, when it takes 18 years to recognize a user's peak load projection?

Respondent 2: OK. You're talking about an econometric projection of the load forecast. That's one thing. I'm talking about a probabilistic analysis of loads and resources three years in the future. The latter picks up the new resource mix, and to the extent there's a lot of solar, and you're calculating an installed to capacity margin, it's going to look like it has to grow a lot, because the solar has hardly any capacity value. But load forecast is another issue.

Question 13: Is there any evidence that more flexibility in the system, such as Texas sees, creates an ability to respond to the unknown better? In other words, if you take the Texas system, which is freeing up a lot of players to respond and incenting them to respond, are they more capable of responding to what we can't predict than in a system like California, where there's a lot of, "Well, we think this is a problem. We think this is a problem and we're trying to prescribe how to deal with it." Do we have any evidence?

Respondent 1: Are you thinking short term or long term, daily response or...?

Questioner: Well, let's start with the short term because that's what we know the most about. But we're also trying to deal with the long term.

Respondent 1: Well, for example, there's one company that came in 2012 or something, and they came to the Commission to say, "Keep up the good fight about the capacity market." Because their business model is that they've got these multiple trailers with generators in them. I think each trailer is 9.5 megawatts, and the registration to become a full generator that has to participate in ERCOT is 10 megawatts. They were going around and putting these trailers on the distribution system in sets of four or five trailers of nine megawatts each. Their original plan was to put 200 megawatts in. I think they exceeded that. Using that model, they also partner now with big box stores. They said, "Look, you're on the distribution system. You need reliability. We can put this in in X amount of time. You'll have your backup generation, and, oh, by the way, if you do that we will help negotiate with your retail provider in order to allow you to monetize those investments in the market. And, oh, by the way, we have the ability to control that, because we're going to bid it into ancillary services, or to ERS." Now, that's not a short term, daily, issue, but they can put that stuff in in weeks or months, not years.

And so, there's a lot of that kind of stuff happening on the distribution system. The problem for ERCOT (and I know they're aware of it, they're working on it) is, how do we measure that? How do we know about that? In the long run, that will affect the reserve margin on the demand side, but is that the right side? Is that the right place for it? Or, should it be treated as generation? And that's evolving now, as I speak.

Question 14: I'm still trying to unpack a previous discussion here. And I just want to offer a quick comment. ISO New England is undertaking now, or will be soon, a project to look at our reserve markets and put in reform. I don't know if it's exactly like the one that one of the panelists

recommended or not, but I know they're looking at it. But I did want to make sure I responded to one thing. The fact that ISO New England has pay for performance doesn't mean we don't have action in the energy market, and of course we only get to pay for performance once we get to a shortage event. Long before that, the real-time energy market sees very escalating prices, which should induce demand-side response as well. So, I didn't want to leave the implication here that somehow nothing's happening on prices that consumers see, or that we're only focusing on

generators. There's also a lot going on that increases the prices for consumers.

Session Two.

Financial Transmission Rights: Theory and Practice

Allocations and auctions for Financial Transmission Rights (whether as FTRs, CRRs, or TCCs) pose challenges for market efficiency, hedging, and trading. Analyses across different markets find different impacts on revenue performance and liquidity measures. In the ideal case, with a fixed transmission grid, fully-informed market participants, and aggressive competition, the pure theory of FTRs offers a solution to the complicated problem of providing a substitute for desirable but impossible long-term physical transmission rights. The realities of less than perfect information about transmission grid conditions, less than fully informed market participants, and imperfect competition have been cited as the source of concern about actual performance. The latest proposals from California have stimulated debate there and raised questions that may be before all the organized markets. What are the best uses of FTRs and how does this affect allocation and auction design? How do the risks and rewards of FTRs affect market prices and auction performance? What changes might be considered that would improve market performance without undermining the basic needs of open access and non-discrimination? What alternatives might be available, and how would they work? What is the baby, and what is the bathwater?

Moderator.

This session will be on financial transmission rights, theory and practice. You all have the description, but it's about allocations and auctions for FTRs (Financial Transmission Rights), CRRs (Congestion Revenue Rights), TCCs (Transmission Congestion Contracts), etc. We'll just use FTRs as the terminology, generally. And then, what's their role in efficiency, hedging and trading, analysis across different markets? We do have seven different ISOs in the United States here, and that also connects with Canada in some places. But they all have different impacts.

And there are some recent proposals that we'll talk about. In California, there are some suggestions about doing things maybe a little bit differently, and so we'll talk about that, and we'll talk about some of the best uses of FTRs and how this affects allocation and auction design.

Speaker 1.

The things I'm going to say are not the official positions or collective opinions of any organizations I am associated with. So, this is a picture of congestion on a monthly level in PJM, and it's for a location pair that I compiled historically, Western Hub to the Peco. So this is a sensible FTR to look at. You do a long-term

transaction at the Western Hub, but your load-serving obligation is in the Peco. You'd want to buy an FTR to hedge that, and why do you want to hedge it? Because it's very volatile. You can't predict what the congestion's going to be. It varies month to month, and it can be very high or very low. And that's why entities that enter into long-term contracts want to hold an FTR or TCC or CRR in order to hedge it.

Part of the topic today is about, OK, well, we have these FTRs and TCCs and CRRs for hedging, but what relationship, when we sell them in the auction, should we expect between the auction price and the payout? And if we were thinking about this as a normal insurance product, insurance companies don't sell me a policy where the payout's going to be greater, on an expected value basis, than what I pay. It's a great ground rule for insurance companies. They build these great big buildings with the deposited difference, not because they lose money. So one question is, should we expect that relationship to prevail in FTR markets? And this slide is the basic idea of them as a diagram. You've got an auction price, and you might have some CRR charges that are collected, and there's the time value of money, because, obviously, it's worth something if you pay a lot in advance and I get the payoff later, and in some auctions the price is paid a lot before the payoff. But if you take account of all those things,

and if it's like a normal insurance market, you'd expect the payout to be less than the time value of money-adjusted price that you pay. And of course, this works conversely if it's negative, because, obviously, if you're buying a negative counter-flow TCC you wouldn't buy it unless you were going to get paid more than you were going to have to pay out, right? So that logic works for both of them, if we were valuing them as a hedge.

Now, in looking at whether or not FTRs are valued as hedges, and consistent with this, one of the problems is that we don't observe the expected payout. All we observe is the actual payout. And this slide is, again looking at the Western Hub to Peco, but now I've looked at the difference between the auction price in the monthly auction and the monthly payout. And even when you get to this timeframe, when you're running the auction just a couple of weeks before the start of the month, there's a lot of variability. And it's all over the place, and that's the point. It isn't even that you can predict what the congestion's going to be, and if I did this where FTRs are sold a year in advance or two years it'd be more volatile, but we'd have a lot fewer data points, so it'd be even harder to see what the central tendency is. But that's the problem, of course, in looking at anything on a short-term basis in FTRs. There's so much variability that you've got to look at it over a long period of time to try to get something about what the expected values are.

So here are a couple of statistics that I've calculated over the years and used at a lot of presentations about FTRs and TCCs that we expect to be used as a hedge. If you take the monthly auction price of a TCC from Zone G (which is upstate, the central Hudson area of New York) down into Zone J (New York City), and you look at that over a 17-year period (so that's going to average out all this noise), you find that, indeed, the price is quite a bit higher than the payout, 111.9%, on average. So that's consistent with an insurance policy that people are willing to pay for in order to hedge congestion. And, similarly, for that Western Hub to Peco FTR, if

you take the monthly prices and average them out, it's actually 141% of the payout. And that's a little distorted, because the congestion pattern switched, so I have got an alternate statistic below that I'm not going to go through, but the idea is it's consistent with what we'd expect for these FTRs.

But then, as Speaker 2 is going to talk about, if you look, overall, at all the TCCs sold in the California ISO auction over a fairly long period (eight years, so that's not just looking at one particular auction), we're looking at a lot of different outcomes. Now, the Market Monitor's figures are not adjusted for time value of money and they mix together monthly and seasonal, so there's some noise in there, but still, the difference, \$740 million of auction valuation compared to 1.4 billion in payout, that's more than the time value of money difference. So there's a big gap there, and while that gap was bigger in the earlier years, a CAISO calculation for a couple more recent years, still shows a large difference--the auction revenues were less than the payout by \$145 million. So that's fairly substantial.

And the reason we're having this discussion is because we don't see, overall, in these California auctions, that the CRRs are being valued consistently with being a hedge. We don't always observe a premium even on this long-term basis.

Another market where I did some analysis, and this is going back over ten or 15 or 17 years, is MISO. And we broke it down in various ways. And you see that, overall, the positively-valued TCCs sold for 94% of the payout, which is close, but still, for monthly CRRs, where the time value of money is not very large, there's some margin there.

But for the expensive TCCs, those over \$1000, we actually see the relationship we expect. The price is more than the payout, about 10% more, and it's closer (92%) for the cheaper ones and only 66% for the relatively cheap. So we got

some that look like they're being valued consistently with hedges and insurance policies, and some that look like they're being sold at a discount.

So let's think about this. Why would it be that we'd sometimes see FTRs being sold at a large discount from the expected price? We'd expect that competition among buyers would drive the price towards the expected payout. Maybe not everybody in the auction is valuing it as a hedge. Maybe some of the people in the auction aren't buying as a hedge, they're buying as a financial instrument, and if we buy something as a risky financial instrument, we're not going to pay a premium, right? Because if I'm buying a bond, I don't buy a bond for more than I'm going to get out of it. So when you turn it around when it's a hedge and it's reducing your risk you're willing to pay a premium, but if you're taking on risk and you're just looking at it as, how do I value this instrument, of course you expect to buy it at a discount from the payout. You want to make an expected rate of return. And, as we get FTRs that are very complex, particularly ones that are complex to value and more risky and more uncertain, maybe they'd sell at a larger discount to the payout.

So this is the idea of the other scenario, where we've got an auction price that's way below the expected price, even when you adjust for the time value of money and other incidental charges, and we've got a large risk premium. And the important point is, that should exist in a competitive market. If it's a risky financial instrument, you're still going to observe it being sold at a discount. And we shouldn't say, "Oh, the market's not competitive." No, the market can be extremely competitive, and still, if it's being valued as a risky financial instrument, it should sell at a discount. And if it's a very complex financial instrument to value, it should sell at a discount.

So lots of competition doesn't mean it's going to take care of the problem. The fact that we have

the discount doesn't mean there's a lack of competition, and having lots of competition doesn't mean you're going to eliminate the discount, if it's being valued as a risky financial instrument.

Now we'll switch over to some California numbers. The California ISO did a large report that they posted in November 2017, doing detailed analysis of a lot of auctions. And this is just one table for December 2016. I think it's striking, in some respects. One, you note that the day-ahead congestion rents are \$15 million. That's the top line. If you look a few lines down, you'll see that the total payments to CRRs, both those auctioned and allocated, was \$31 million. So the payout was almost twice the congestion rents. And the idea is, of course, that the congestion rents are supposed to fund the payout, not that the payout should be twice the congestion rents collected in the day-ahead market. So that's one thing that's interesting about this statistic.

And another thing that's interesting is, if you look at the auction valuation of the CRRs that were sold in the auction, that was only \$8.8 million, but the payout was \$14.5 million. Now, this is only one month, but we've already seen that this is true over time. But here's one month where you see there is a big gap between the valuation in the auction and the payout.

So one of the questions is, why do we see such a situation in the CAISO and not other places? One of the things that's important about New York ISO is that a lot of the buyers of TCCs, and a lot of the people that are in the market as load-serving entities, are not regulated. And if they lose money, they lose money. If the price spikes up, and they have to sell at a loss to their retail customers, it's not in rate base. They lose money. They go broke. Their boss fires them. So there's an incentive to hedge. And while there are some providers of last resort service by the utilities in New York, there are a lot of just plain competitive retailers. If they don't hedge, and market blows up and there's congestion, they go broke. So they

hedge. And they're willing to treat it like an insurance company. They'll pay a premium not to go broke.

In California, that's not necessarily the case. There's a lot more of the retail load that's served by the big three investor-owned utilities. It's not clear that they have an incentive to hedge the risk, as opposed to just passing it through in rates the next period. And it may even be that the CPUC's policies towards hedging by the utility are a disincentive. They're in a situation where, if they hedge and it turns out to be a good idea, they share the winnings, and if it's a bad idea, they eat it. So they may have a particularly bad incentive to hedge, compared to other areas. So maybe part of this is a lack of hedging demand. So that's one of the questions that, you know, I think we ought to ask – you can go and look at all the CRRs that are allocated and value them in the monthly auction prices and compare them to payout and say, are the kind of CRRs that the LSEs are selecting in the allocation process, are they valued consistently with hedges, or are they sold at a discount? Because this market's got a problem, in that it's so much driven by regulation that there's no demand for hedging. And that's an analysis I think ought to be done, but, as I noted at the bottom of the page, it hasn't been done. It's one of these things that we don't know how it would come out.

So then we ask, well, OK, why would so many of the hedges that are sold in the auction have so little value as hedges? And part of it may be because the load-serving entities aren't buying it. But roughly 75% of the transmission system is allocated to the load-serving entities, in terms of in the allocation process annually. And then another 7% is allocated to the load-serving entities in a monthly process, and then it's only the residual that's available in the auction. So there's a lot of the system that's allocated, and what's left for auction isn't that big.

Another really interesting statistic I found is that if you look the couple year period (2015-2017)

where the CAISO prepared this data, the total CRR payout going to the allocated CRRs was only 54%, even though 75%, 82% of the system was made available for allocation. You'd think that that was most of the congestion rents, and that was all that was being sold. But, wait, that's only actually about 55%. A whole lot of the congestion rents, or actually the CRR payout, was on the other stuff that was sold in the auction that no one wanted in the allocation process. So that's an interesting fact.

And the CAISO's done some additional analysis, and a lot of the CRRs being sold in the auction, and a huge amount numerically, are generator-to-generator, generator node to generator node CRRs that aren't tremendously valuable for hedging a load-serving position. There are situations in which it makes sense to do that. If you have an outage at one generator, and you want to change your hedge from Generator A to Generator B, you just buy a CRR from A to B. But when you look at 130,000 or something CRRs being sold in the auction from wind generation nodes, that obviously wasn't because we had 130,000 people that needed to change their hedge that month. So there's something more than that driving it up. It also is possible that, well, these could be counter flow, people taking a little bit of a counter flow position where they thought the thing was overvalued. But, of course, A, we're talking about a market where the CRRs are undervalued, so you don't make money selling counter flow in an undervalued market, and most of the CRRs, collectively, are exacerbating congestion, backing out other things, not creating counter flow, according to analyses the CAISO did.

So the question we're left with is, why is the auction value so low? And a straightforward, simple answer would be, "Well, it's just because there isn't any demand for hedging in the CAISO," and it'd be nice to do some analysis that would rule that out. But then you ask, "Well, why is it that there's so little demand for these FTRs as hedges when 45% of the payout is going to

these?" That's a lot of FTR payout going to stuff that has no use for hedging. Now, the ISO has done some even more detailed analysis, and one of the things that pops up is that a lot of the payout is to constraints that didn't bind in the auction but bound in the day-ahead market. And that could be just because, well, you know, there's a lot of variation and every day you can't predict. As I pointed out with those charts at the beginning, you don't know what's going to happen during the month at the beginning of the month. Even near-term, you get surprised. So it's not totally surprising that you get different constraints binding. But it also might be because the CRRs that are being bid in the monthly auction or some of the other auctions are tailored not to create flows on binding constraints, but only to create flows on constraints that are not enforced in the auction. And maybe those particular CRRs have very little value as hedges, because they don't really hedge any market obligation, and they're so complex to evaluate that they sell at a big discount. So that's another thing to look at.

And, in fact, the CAISO analysis shows some examples of this, and for the December 2016 auction, in fact, the three largest constraints, that accounted for \$10 million of the payout, none of them bound in the auction.

This is one of the pages from the CAISO report. This shows all the constraints, with payouts, from the seasonal auction. You see a bunch of payouts on the left-hand side. You see a bunch of zeros on the right-hand side, because none of them bound.

And this is the same data for the monthly auctions, and you see the same pattern. It's almost always zero in that column in the middle there for what the payout was in the auction, so they weren't binding.

And here's another detailed table that they put in there that shows the limits and what was binding, and a whole lot of them weren't even enforced. So the constraint that gushed a lot of the money, in fact more than all of the difference between the

auction revenue and the payout, is due to the payout of constraints that weren't enforced in the auction. Now, that can have to do with a lot of surprises, and so forth, but it's an interesting pattern. Sometimes accidents happen, and mistakes, and things don't get modeled, and that why a constraint wouldn't be enforced, but it also can be that this is a constraint that doesn't model and it wouldn't bind, one that can't be modeled in the all line in auction grid model, but only can bind when you have some lines out of service and then there's a contingency with line X out, so then line Y can bind in the contingency, so there's no real way to model that. And other ISOs have outage contingencies that they put in the day-ahead market that they can't really model in the auction.

So, to go back to that \$31 million of payouts and \$15 million of congestion rents, that's a pretty stunning number, I think. And maybe what we've got is the CRR payouts being magnified by CRR bids that are structured to create flows on constraints that create payout. but they actually don't correspond to anything in the day-ahead market. They're structured to create large flows in the payout. There is no day-ahead market transaction corresponding to that, so you don't actually collect the congestion rents of the day-ahead market.

Now, I've sort of set up the problem. Speaker 2 is going to talk about some of the solutions.

But I want to talk to another subject, which is alternative FTR designs. Instead of alternative auction designs, let's talk about something that's a little different. And I and others here go way back in the development of FTRs, and there's some parts that were rigorously worked out, and there were some parts that were done sort of really *ad hoc* by the ISOs. And those of you who remember those days, you know, we spent all our time arguing with Enron about LMP, and no time talking about how we're actually going to implement this stuff. So there were some decisions that were made sort of on the spur of the

moment that maybe we ought to reconsider. And one is that the way that FTRs are settled actually isn't consistent with the revenue adequacy theorems on which they're premised. Because what we usually do is we award FTRs based on a revenue adequacy theorem that says that they have to be simultaneously feasible on the auction grid. And then when we settle them, we settle them based on the congestion rents in the day-ahead market based on the day-ahead market grid.

And that isn't the only way you could do it, you know. When you have those differences between the auction grid and the day-ahead market grid, Bill Hogan's revenue adequacy theorem shows that you have the potential to be short. But you don't have to open yourself up to that. You could instead settle the FTRs based on the shift factors in the auction applied to day-ahead market shadow prices. And that would provide a hedge for congestion consistent with the transfer capability of the grid, but wouldn't have some of the same results.

Now, this would be complex to implement, because you'd have to calculate shift factors on the auction grid for all the day-ahead market constraints. You know what they were on the day-ahead market. That comes right out of the software, but you'd have to do a special run to calculate those shift factors for settlements using the auction grid. But it actually isn't impossible, because the New York ISO's been doing precisely that since 2005, when it allocates the cost of outages to the transmission owners. So, since they've been doing it for 12 years now, it's probably feasible to do.

Now, that kind of design would eliminate most of the congestion rent shortfalls in the day-ahead market, because it would eliminate the impact of transmission outages and differences in loop flows and differences in loss flows from creating congestion rent shortfalls in the day-ahead market. They would not, however, eliminate

congestion rent shortfalls due to a just plain line derating, but that's not a lot of the problem.

What got me thinking about this, and it ties into some of those California numbers I was ranting about, is that while revenue adequacy and auction valuation are not the same thing, they're not completely independent. And maybe they are a lot intertwined because of the way we settle them. And because of the way we settle them, maybe that's leading to both the revenue inadequacy and the poor valuation. Because if you settled in this way, it'd no longer be possible to go into the auction and buy FTRs between two nodes that had no hedging value and didn't create any flows in a binding constraint on the auction grid, but you know that an outage of line A is going to go into effect on 12 days during the month, and you know that when that outage occurs, the shift factor on a binding constraint is going to go from 2% to 20%. You know you can make money off that. And that's not going to get valued into the auction, because that's not the way load-serving entities are valuing that hedge. So that would end. And all the resources that go into finding those situations, we'd no longer be spending resources on it.

Now, it wouldn't eliminate the potential for people to load up on CRRs or FTRs that create flows on a constraint that wasn't modeled in the auction, but that's another problem to think about. But it would affect part of the problem, and maybe a lot. And this is one of the things where maybe the ISOs could do a little more careful analysis of what's leading to revenue shortfalls in payouts and see how much of the payout is due to things like this.

Another thing that this would do is, if you settle based on the auction grid, you could also settle it based on auction model load distribution factors. In other words, the FTR would be settled based on the day-ahead market prices and the auction load distribution factors. And that's what PJM has done for many years, but most other ISOs don't. Most other ISOs settle it as a perfect hedge,

even when it's not a perfect hedge, and they settle it based on day-ahead market load distribution factors, which leads to revenue inadequacy. But it also may lead to the ability of market participants to create bundles of point-to-point and point-to-load-zone and load-zone-to-point FTRs that on the auction grid net to no flows on the relevant binding constraints, but when you get into the day-ahead market, based on day-ahead market rates, they net to flows. So that would be another way in which the problem is that the FTRs have been defined as a more perfect hedge than they really are, and people found ways to generate revenues from that.

So, these are the thoughts about an alternative way of settling FTRs that are rattling around in my brain as we look at some of the data from California. There are two other points that I think that are relevant here, related to the New York ISO. And you know, the NYISO tracks monthly metrics. They track what the payout is and what the auction price is on a bunch of the TCCs. So they're tracking how this metric looks, and there's a discussion each month and each capability period of how much FTRs and TCCs should be sold on two years, one year, six months, to try to tailor the mix to the load hedging needs so that things get value.

There's a diagram in there that shows the congestion on the central east, the west to Dunwoody constraint, and you'll see, my God, in the winter of 2017-2018, that congestion goes out of sight. It's even higher than into New York City. But it highlights the fact that when you're thinking about how FTRs and TCCs are being used to hedge, it isn't even necessarily the LSEs within your state, because I'm the sucker on the other side in New England. Why is there high congestion across central east in the winter in New York? Because New England's on the other side. It isn't just New York that's on the other side, it's New England. So if you're a New England load-serving entity you would want to own TCCs across central east to hedge your cost of serving load in New England, even though

you're not a New York LSE and wouldn't get any TCCs if we simply allocated TCCs to New York load-serving entities. So I'll stop there and pass the baton to Speaker 2.

Speaker 2.

It's an honor to get invited to speak to you all here and to talk electricity market design with the other esteemed members of this panel.

So, at the DMM, the Department of Market Monitoring at CAISO, we think the FTR auction design is fundamentally flawed. That doesn't mean that we don't appreciate that there's value in what the FTR auction is trying to do. There's value in there being a mechanism which can facilitate efficient transactions and efficient prices for hedges between the thousands of dispersed generation and load injection nodes and the more limited number of centralized trading hub prices nodes where you get a more liquid market for energy contracts.

So there's value in what the auction's trying to do, but we view the FTR auction design as flawed, so it doesn't do a good job of facilitating these kinds of efficient transactions for these hedges. It results in a whole lot of inefficient transactions and massive losses to entities that participate in actual physical power transactions. So in an ideal world this debate, going forward, would be about, what are alternative mechanisms besides the FTR auction design? However, obviously the status quo has a lot of inertia, and so in order to convince policy makers, decision makers, to move forward and move on from the status quo, we need to continue pointing out what's wrong with the auction design. So that's what I'm going to spend my few minutes here talking about today.

DMM's critique is not of the FTR allocation. Our critique is of the FTR auction. Auctioned FTRs are fundamentally different from allocated FTRs, but in order to get into what our critique is of auctioned FTRs, I need to talk a little bit about what allocated FTRs are. So, the entities that pay

the transmission access charge (we call it TAC in California) are paying for the transmission and paying for that steel in the ground. That transmission asset then produces revenues, right? The entities who pay for an asset to be built, they're the rightful owners of any revenues that that asset produces. For physical transmission, the revenues it produces are the congestion rents in the day-ahead market, right? Load pays more than generation gets paid in the day-ahead market, so there's revenues there. And so the entities who pay the transmission access charge are the rightful owners of those congestion rents.

So allocated FTRs are a pretty clever mechanism and serve a dual purpose there. They do allocate those congestion rents back to the rightful owners of the congestion rents, the people who pay for the transmission. And they're also a way of providing entities who pay the transmission access charge a mechanism for having hedges on their basis risk between the nodes in which they sign their forward energy contracts and those at which they're buying the load from. But the last point here's kind of the key point for our critique of the auction. The allocated FTRs can't allocate out all the congestion rents, right?

When I say "allocated FTRs," I know there are Auction Revenue Rights in PJM and other ISOs, but they're essentially the same mechanism. Just think of the allocated CRRs in CAISO as self-scheduled Auction Revenue Rights in the FTR auctions, which is essentially the same thing. So, after the allocation process, there's still going to be a pool of money left over of congestion rents that aren't assigned through this allocation process. That pool of money isn't a free resource that people can do whatever they want with, right? That congestion rent still belongs to the people who paid the transmission access charge. And in most ISOs, definitely in California ISO, if there was no FTR auction after the allocation process, those congestion rents would be allocated back to the entities that pay TAC through the FTR balancing account. And it's a different allocation mechanism than the FTR

allocation, but it's a *pro rata* way of getting those congestion rents back to the entities who own those congestion rents.

So, now let's talk about the FTR auction. This is the standard story that we all learned in graduate school. And all of these elements have things that are wrong with them, which together lead us to the conclusion that there needs to be fundamental changes to the auction, and there should be a new mechanism that's developed to facilitate efficient transactions for these hedging instruments.

The first part of the story is what I just talked about. The standard story, that those leftover congestion rents after the allocation process are a free resource that can be used by central planners, like I just said, that's not true. Those congestion rents do belong to the entities who pay TAC, and so I think it's kind of an anti-market sentiment to say that those congestion rents can be used by a central planner to try to engineer something for the greater good.

The second aspect of the standard story here is that if the one single auction model that is used in the monthly auction were somehow to be able to equal all the many different day-ahead market models used in the day-ahead market, then auctioning FTRs would be the equivalent of auctioning off leftover congestion rents. But, again, the one single static model used in the FTR auction never has and never will equal all the different variations, all the different day-ahead market models due to transmission outages. So the auctioned FTRs are not auctioning off congestion rents, as we'll talk about in a couple slides from now. They're just financial swaps.

This next bullet is from the ISO stakeholder initiative. I've heard a lot of people saying that my team and I are wasting our time on this initiative, that if we follow 205 or 206, FERC's going to reject it because FERC thinks that ISOs have to auction off FTRs to allow generators to have their hedges. So we dug into the literature for different FERC proceedings. We haven't found evidence

of that. If anything, you can go back to the last white paper on FERC Standard Market Design. It implies that FERC was intending, actually, to not force ISOs to auction off additional FTRs after the allocation process. When it comes to talk about FTRs being hedges in FERC orders, they're referencing *allocated* FTRs being hedges for load-serving entities--for transmission customers, which I interpret as entities who pay TAC. So, the point there is that we have no idea what FERC thinks, so we have no idea how FERC's going to react when presented with new evidence and with the issues with the auction design that we're putting out there. So I think it is worth my time to continue working on this stuff.

Probably the key assumption in justifying the auction design is that if the auction design is a competitive market, then everything's going to be fine, because the auction revenue should converge to the day-ahead market payouts, and so the entities who are being forced to auction off these instruments would be indifferent, they wouldn't care. For various reasons, as we've written in our papers, the FTR auction design does not have the features of a competitive market. We should not expect the market outcome to be a competitive market outcome. In fact, empirical evidence that we've seen from California and the other largest ISOs show that the outcomes are not competitive.

From my perspective in California, there are certain points which are giving decision makers the most pause in terms of moving forward with the recommendations that the Department of Market Monitoring is making, which is to, essentially, instead of forcing people to auction off these FTRs, make any kind of market for these things actually be between willing buyers and sellers.

So the first objection is that the auction design is necessary for open access to transmission. We don't see that at all. The day-ahead market ensures open access to transmission. The day-ahead market ensures that the lowest price bidder

gets access to the transmission. Entities can feel free to sign forward energy contracts, knowing that they will have open access to an ISO's transmission system. So, if there were no auction, or the auction were redesigned so that the limits of the auction were set to zero, then hedges for basis risk would still be available. It's just that they might not be available at a price below which entities who want to buy the hedge are willing to pay for it. So I think the argument for open access comes down to price. I think the argument for open access is that, "Well, if these guys can't get a hedge, then the price at which they're going to be willing to sell the energy contracts is going to be higher."

So I think the argument comes down to an argument about pricing efficiency. I really think this is where the argument is, at in terms of what at least California ISO management is proposing to do,--that is, this question of whether lower prices on some forward energy contracts justify accepting the flaws in the current auction design. And so we're doing analysis on that, and we're finding that you can look at, the question, how much would forward energy contracts go up in the worst-case scenario for entities that are currently buying CRRs to support forward energy contracts? If no one could get any of those CRRs at a price below what they're willing to pay, then how much could forward energy contracts go up? We have a draft analysis, and we're finding that the amount that they could go up is significantly less than the amount of losses on auctioned CRRs that are accrued to CRRs which have nothing to do with actual physical energy transactions. We haven't put out that paper yet. We're still doing some edits on it, and obviously people will question our assumptions, but we're confident that the sky will not fall, electricity markets won't fall apart, if you adjust the auction design to only be between willing buyers and sellers.

To get to what we view as the fundamental flaw in the auction design, I think it helps to think about the underlying transaction for an auctioned FTR. Every auctioned FTR is between a buyer

and a seller, so if you think about an auctioned FTR over a constraint which is fully occupied by allocated FTRs, then someone's buying the FTR, they're paying a fixed price to the seller, so it receives a fixed price in the auction, and in exchange the seller is then obligated to pay out the floating difference in day-ahead market prices between two nodes. So that FTR is a fixed for floating swap.

So now let's think about what an FTR is that's related to the leftover transmission that's on a constraint after the allocation process? Here's an example of a transmission line. The dotted blue line down through the middle there, that represents the limit on that line that's used in the FTR auction, so the ISO anticipates that the limit of that line in the day ahead market's going to be about 100 megawatts most of the time. In the allocation process, 55 megawatts of that line are used up by allocated FTRs. So then there's 45 megawatts left over on that line for the auction. Those 45 megawatts left over on that line, those are going to clear in the auction. Those are going to be sold to the highest bidder, regardless of how low that highest bidder bids. Even if that highest bidder bids one penny, those FTRs are going to be sold for that one penny, and the revenues from that sale are going to go into the FTR balancing account. In exchange, the FTR balancing account is going to have to pay out the shadow pricing on that constraint over the course of all the day ahead markets. So that leftover capacity on the constraint, those are FTRs that are also fixed for floating swaps. Moreover, those are fixed for floating swaps which are being offered at a zero-dollar reservation price. And then who's selling them? The entities selling the FTRs are the entities who are receiving allocations from the FTR balancing account. And in most ISOs, like California, those are the load-serving entities. Ultimately, it's the transmission rate payers.

So the main story there is that the limits on these constraints used in the FTR auction, that's defining the quantity of these financial swaps that transmission rate payers are being forced to offer

at a zero-dollar reservation price. That's a fundamental flaw in the auction design, because it results in inherently inefficient transactions, textbook inefficient transactions where the transaction's taking place, but the price the person selling it willing to sell it for is higher than the price the buyer is willing to pay for it. If you think about your Econ 101 supply-demand graphs, it's the wrong side of the intersection point. It's a classic inefficient transaction, and it results in huge losses to entities engaging in actual physical power transactions.

Here's a graph we've put out a lot over the years in DMM. The blue bar is showing the auction revenues received by rate payers; the green bar shows the payouts from rate payers to auctioned FTRs, and so here we're seeing what happens when we have an auction design where the sellers, the rate payers, are forced to sell a huge quantity of financial swaps at a zero-dollar reservation price. You get huge losses. And this is not a problem just in California. This is a problem in the other largest ISOs in the country. Rate payers are losing huge amounts of money from this FTR auction in the biggest ISOs across the country. It's not just a California issue.

So, how to fix this flawed FTR auction design? The proponents of the auction, many of them say, let's just address the revenue inadequacy. If you were to lower the limits of constraints in the auction model, that would certainly reduce revenue inadequacy. It would reduce rate payer losses, right? It would increase auction prices. It would reduce payouts. But there's no reason to believe that the rate payer losses would actually go to zero if revenue adequacy were achieved, right? Because you're still setting the limits based on what you expect the line limits to be in the day ahead markets, and rate payers are still being forced to offer this huge quantity of financial swaps at a zero-dollar reservation price. The best empirical example we have of this is coming out of MISO, data that MISO put out over the last six or seven years. They've achieved revenue adequacy, and yet, over those six or seven years,

rate payers have lost over a billion dollars from auctioned FTRs. So, we don't believe that just working on revenue inadequacy is going to solve the problem.

Our proposal is to address the fundamental flaw. The real flaw here is that the auction uses an estimate of what that full network model's going to be in the day-ahead market, and that determines the quantity of these financial swaps rate payers are being forced to offer at a zero-dollar reservation price. So, what we're proposing is to stop forcing rate payers to offer swaps at zero dollars. If you do that, if you stop flooding the market with hedges that are being offered at zero dollars, that can actually allow a new type of market for these hedges to develop, a market which is between actual willing sellers, instead of conscripted sellers, and willing buyers. That's it.

Speaker 3.

It's a pleasure to be here and to talk about these things. I would say that, like many of Speaker 1's presentations, wow, that was complex and hard even for me to understand, and even the part that Speaker 2 talked about very hard to understand. And I think that this issue isn't nearly as complex as people make it out to be. I want to try to see if I can get to really simplify it, and I think that there are some distinctions that have to do with California having very specific issues, and I'll get to those at the end, but I wanted to talk about the role of FTRs in the market design in general.

One of the interesting things about open access, non-discrimination, transparency, and liquidity in the market is that it's really hard to prove the value that you're getting from it. Europe doesn't have ISO-centralized dispatch. They require balance schedules. They have very inefficient dispatch, probably to the tune of billions of dollars a year of lost opportunities. And yet, nobody necessarily sees it. So Speaker 2 can argue that, hey, if you eliminated these markets, prices wouldn't necessarily go up. And you're right, you wouldn't necessarily see it. It would

just be chipping away at the fundamentals of open access non-discrimination that FERC has designed these markets around.

From my perspective, the core issue is that FTRs play a crucial role in the market design. They're essential, and it's important to understand why they're a necessary component. A lot of the markets started without LMP. PJM started without LMP. That failed. California obviously failed spectacularly without LMP. New England also. Nodal pricing is the only market design that works for competitive markets and takes into account the network externalities on the grid. It's the only one that works, and I think that there's a common understanding of that as the "Successful Market Design," as I've heard Bill refer to it. And I think that my colleagues here would tend to agree with that, but I think they've also forgotten why nodal pricing was resisted so much in the first place. We couldn't have nodal pricing, opponents argued, for many of the same reasons that Speaker 2 is now bringing up--that bilateral markets can take care of it, and you can get your hedges at a specific location by going to a bank, or going to Enron, or whomever it is.

When there's congestion, prices are different everywhere on the grid. It's very complicated. And the market participants argued that you would never have forward trading hedging in the bilateral market if you had such a complicated market design. The long-run resource allocation decisions, entry, exit, new units--banks today go and they write hedges to generators at specific locations, and they take the risk at the busbar. And they rely on FTR markets, and just even the mere existence of them, to know that they'll be able to cover those costs. They build in a premium, but how much higher would that premium be if in fact we didn't have this market design?

The other piece of this is that congestion is actually a pretty small part of the costs in the market. They're relatively small, but they're really, really important for getting the prices

right. You want to have efficient dispatch based on nodal pricing, and, again, the ISO market is the only market design that does that. And the FTRs are actually the solution to the question, or the problem statement, that opponents had with LMP in the first place, saying, “It’s too complex, you can’t hedge.” And the way the actual market design now works is that you can actually have traded hubs and zones where there are liquid-traded forward trading, and FTRs are a part of that. And the FTRs actually get you to your specific location and deal with the risk to get to the specific location. So in the market design, having the FTRs is really important in order for these futures markets to work well.

And if you think about markets like PJM, where I think there are huge benefits from competition, there’s private equity willing to build an endless supply of new power plants in the eastern markets and have competition based on basically getting single-digit returns. It’s very, very competitive. Prices are very low. But to go into these markets and look at a region like PSEG, where, this winter, there were extreme price spikes in January during the polar vortex. Well, the ability to go and get hedges for those locations is really augmented by the fact that the ISO is facilitating a market for these things.

So one of the roles of the FTR auction is to allocate the rights to people who value them, and it is a market mechanism for doing that. And it does return the rights to the rate payers who pay for the transmission grid. But another benefit that having ISO auctions provide is in creating a market for congestion and disciplining the forward market for congestion and ensuring that there is this liquid and transparent market.

Let’s think about a retail market, like pretty much all of PJM. So this is partially a difference with California, but not the only difference, and I don’t think it’s the most key difference from California, because, as Speaker 2 alluded to, there are speculative players in all of the FTR markets, including PJM and MISO, and there’s also

hedgers, and there’s also hedgers who are generators. And a lot of times those hedgers who are generators might be in the same location as a hedger who has a load. So if you’re a generator in PSEG, or in PECO in Speaker 1’s example, you might also be hedging, but the prices are different. You’re not getting that premium that Speaker 1 sees in PECO. And one of the things that the FTR auction is doing is allowing for there actually to be a clearinghouse for that that gives you the lower prices than you would get if you had to go to Goldman Sachs or Mercuria or BTG or some other entity for covering your hedges.

Now, if you’re in a retail market, like New Jersey in this example, there’s probably 300 to 400 different retail competitive providers who are willing to serve your load at your location, and if you don’t want to do that you’re in the full requirement service auction, which in New Jersey’s called the BGS auction, Basic Generation Service. And what matters to those consumers is not what the price of the FTRs is and who’s making money from them. What matters to them is how liquid and transparent is the market for congestion that the ISO is facilitating, and what is the risk premium that is going to be charged me in this auction from participating? And that risk premium, in turn, depends on the liquidity and transparency of the market for basis at your specific location. So if there’s not a lot of liquidity in transparency and FTRs aren’t available, I would assert that the risk premium that market participants charge in the futures market will be that much higher, and plenty of market participants who participate in this...maybe the market participants want to get their allocated ARR rights and convert them to FTRs, but maybe they also want to convert them into a different set of rights that better matches their risk profile, and they don’t necessarily want to buy FTRs, because they have different risk in the market. And maybe they have a complex set of generation and load.

I know when I was at Edison Mission, we managed power plants at specific locations. We

did some load deals. We did origination deals directly with customers. We also had a speculative FTR portfolio. A lot of times, in order to do all these things, we weren't necessarily looking at just buying a generation-to-load hedge. In fact, there was more risk sometimes in buying a generation-to-load hedge, because when our generation was down we might have congestion in to the generation. It's a problem a lot of wind plants face as well. And so what we were looking to do is similar to a little bit of what Speaker 1 was thinking about, which is to buy a portfolio of congestion contracts that better matched the risk of our firm. And in fact, if you think about it from our investors' perspective or our management's perspective, our investors weren't interested in having specific risk around, say, Homer City or Chicago. They'd like exposure to the whole PJM market. And so by diversifying, through a portfolio of FTR contracts, we were able to capture exposure to congestion across the market and better match our needs. Now, it's still a competitive market for the FTRs.

So what about this argument that, well, if the financial traders are making money, then consumers must be losing money? It's very seductive, but I think it's also in conflict with the notion of market competition and the benefits that we've had. And I think it's important to distinguish the baby from the bath water in this whole thing.

I do agree with Speaker 1, it's been getting better in California, but California FTR auctions have been a bad predictor of the day-ahead congestion. That's not true in the other ISO markets. I'm not saying that there aren't model differences in the other ISO markets, but California uniquely has done a poor job of having the modeling in the FTR auction match what actually binds. What we see in California is sometimes because of outages, but outages happen in every market. In California, the operators choose to operate the system, not based on the security constrained dispatch, but by applying very complicated nomograms that result in very conservative limits

on the system, which actually harms the efficient dispatch of the system as well, but results in very high price spikes with certain transmission constraints. And I don't know if it's because of the little other control areas within California that they're dealing with, but I think it's the use of nomograms and the extent of the use of nomograms to limit flows within California is really extreme relative to other markets.

That relates to a second issue, or flaw, I would say, in the California market, which is that they oversell the system. A basic principle of the LMP design is to only auction off the transfer capability based on the revenue adequacy theorem, so that you're going to collect enough congestion rents so you're revenue adequate. Most of the markets have done a pretty good job of that. And one of the problems that California has is that they have a lot of revenue inadequacy, which the loads end up paying for. They need to fix that.

That doesn't address Speaker 2's question. In competitive markets you're going to get profits for market participants, and the question is whether the benefits of those competitive markets, the baby, the hedging, that sort of thing, outweigh the bath water--maybe there's some model differences where people are able to make profits off of those model differences.

I'll turn a little bit to California on the retail access side of things. In California you do have a competitive FTR market, or CRR market, but you're building generation based on RFPs and IRP, and the utilities giving a contract at the load location, and there hasn't historically been a lot of retail access. And it may depend on where California wants to go. Maybe they want to go towards more competition, but if you only have competition in CRRs, in California, and nothing else, maybe there's not really a point to it. But I would hope that we could get something better in California, where we're trying to introduce more competition.

Speaker 4.

The basic point that I'd like to talk about is what I'll say is financial transmission rights that benefit both consumers and producers. And the thing that I think is important is, yes, financial participants can increase the quantity of FTRs available. Effectively, they can sell counter flow between two points that a load or a generator might want to have an FTR on. And in that sense, I think there is a clear financial and economic efficiency benefit associated with the financial participant.

That's also the other reason why one could argue that even though these financial participants may be earning returns, those returns could be smaller than the benefits that they're giving to the load-serving entities. Moreover, in a loop network it doesn't even have to be a counter flow on a specific FTR, it can be simply that you're putting in and buying FTRs at certain locations on the grid, which is expanding the amount of FTRs that a load-serving entity or a generator can use to hedge its specific deal. And so, in that sense, as I said, there is a role for financial participants, and they do serve a market efficiency role, potentially.

And what I think this first suggests is that before we throw out the baby with the bath water, so to speak, I think trying to get into doing such an analysis would be very helpful. The point being here that purchasing can increase the efficiency, for the reasons that I just outlined, and periodic auctions by the ISOs are an ideal mechanism for allocating the FTRs among market participants. So what's the problem with FTRs? The problem, at least the way that I see it, is how we fund them. We fund them, essentially, from the revenue collected from the sale of FTRs, which is, as we said, typically lower than the revenues paid to owners of the FTRs, and in many of the markets, those are typically going primarily to generation owners and financial players.

And I think what happens is that the current FTR market design conflates two issues. Number one is to provide market participants with the ability

to hedge basis risk, which is a very noble cause, and then the other issue is this need to distribute the merchandising surplus resulting from the transmission congestion back to market participants. Currently, the paradigm effectively funds this through the merchandising surplus in the short-term market. In other words, payments to loads greater than payments to generators should, under simultaneous feasibility, be paying the FTRs back. And it's that that I think is really what the core of the issue is, in terms of why we get this problem with FTRs.

So, just to give a little empirical analysis from the New York ISO TCC auctions, this is based on work that a student of mine, Gordon Leslie, has done looking at these things from 1999 to 2016. And the basic point of his analysis is that for the most part retailers are doing pretty much what Speaker 1 said, in that they're buying a hedge, and typically what they're paying for the contract is a little bit less than what they're getting back. They're getting insurance. But for the asset-owning generators, it's the opposite. They are getting a significantly greater payout. And for financial participants, they're getting even greater payouts. And Gordon did a study of all the DMM reports, and based on most recent years, he found roughly about \$600 million annually in excess of what was paid at auction was what the payouts were. And it is true that California was by far the largest, but this is not unusual across all the ISOs. New York is the perfect example.

So, as probably everyone knows, these are monthly, biannual, and annual auctions, and so one of the things that we did is just to look at who is actually getting paid in these auctions, with the payouts. And what you can see is that, for the most part, it's the financial players and the generators that are getting the payouts from the TCC auctions. As you can see, the retailers are getting very little TCC payout. It is true that they are getting a significant amount from grandfathered TCCs, but in the auctioned TCCs, they're getting very little.

The other thing you can see is that there are a massive number of products that you can bid on in these auctions, I mean, tens of thousands of these products. Think of it as every point to point that you could imagine (except in the case of New York, where you can only sink to load in a zone). But, again, you can see that for the most part retailers aren't bidding on very many of the TCCs. It's primarily the entities that own generation assets and the financial participants that are bidding. And this just shows the same information for the annual TCC auctions. Again, there's very little participation of retailers.

So the other thing about these auctions is that a result of the fact that you're selling so many products, how many firms are actually bidding on each individual product? I think this goes to the point that Speaker 2 tried to make, which is that, for the vast majority of the things that are auctioned, there's essentially one bidder for that product. And then next in line is two bidders, but for very few products are there a significant number of bidders. Now, it is true that what I bid on one TCC goes to the network model to influence the competition that another entity might face for that TCC, but for the most part you're spreading a finite number of market participants over a massive number of potential TCCs, and it sort of stretches credulity that there's going to be adequate competition for each one of these products to get the outcome that we would like to see, which is essentially that the amount that you pay is equal to the amount and expectation that you exactly receive from that TCC.

And this shows the same sort of thing for the annual TCC auctions as well. For the most part, one firm bidding on a given point to point TCC is really the vast majority. As I said, there's a whole lot of these things, a small fraction bid on, and even a smaller fraction bid by multiple firms. The financial players are really the big guys that are making money in these auctions, and they're the ones, as the first diagram showed, who are essentially getting paid far more than they are

paying to purchase the things that they're getting paid for.

So one of the things that makes this difficult, and that certainly is a challenge in California, is that there isn't a big appetite for retailers to engage in speculative activities. Given regulatory rules as well as informal regulatory rules, they're primarily interested in just purchasing TCCs to serve their load. In terms of the set of bidders, there's pretty much the things that retailers, financial firms, and generators bid on; there's the set of stuff that generators and financial firms bid on; and then there's the even larger set that purely financial firms bid on. And, as we said, it's a pretty thin market, and thin markets you don't necessarily expect to be accurately priced.

So the question is, how do other forward markets, futures markets, handle this problem of thin markets? Well, they handle it through a willing buyer and willing seller way similar (I think, anyways), to the way Speaker 2 discussed it. But as I said, many of the TCCs that are sold to the financial firms and generators just result in simple transfers from consumers to these entities, largely, as I said, because of the fact that the payout is greater than the amount paid. And the other thing that I think is very important to emphasize, as Speaker 2 discussed as well, is that there is a requirement that the ISO actually auction off these TCCs and funds them through the merchandising surplus. And what this means is, essentially, because of how they're financed, the ISO can forever and forever sell a derivative product that it persistently loses money on. And if you think about that, you go, "Well, gee, there's no private firm that would ever do that." I mean, the second that a private firm continues to sell a derivative that it persistently loses money on, it's going to stop selling it. It's going to say, "I don't think I want to do that, because that's just giving away money," but because of the way that we finance the TCCs, and because of the mandate that the ISO actually must auction off this merchandising surplus, this can persist

indefinitely and result in what appear to be these large transfers.

Now, again, I would caution that some of these transfers could reflect the fact that, yes, we're paying these entities for the fact that they're providing counter flow that can then provide larger quantities of hedges for the physical players in the market, but you need to do an analysis to actually figure out whether or not that really is the case. And that requires, unfortunately, access to confidential data (which I would, as a shameless plug be very happy to get and do the analysis).

So, as I said, the problem with TCCs is not their existence; it's not the auction mechanism; but it's how they're financed. And I think the problem can be addressed only by having willing counterparties, meaning another market participant that finances all the TCCs that are sold, not this passive counterparty, the ISO, that on behalf of rate payers basically says, "We will back up any TCC that is sold." And if what you did is, you went to a TCC market where effectively it was a willing counterparty that sold the TCC, you'd eliminate the revenue adequacy, because contracts have to be enforced. In other words, if you sold it, you've got to enforce it. If you bought it, you're going to get it. The other thing is, it eliminates the problem with thinly-traded TCCs, because no one would offer a TCC they expect that they're going to lose money on. And so what you would get is effectively only the sales for products that there is a willing counterparty to essentially sell to a willing purchaser. And, as I said, the ISO is currently sort of a forced counterparty. It can't refuse to sell a TCC, even if it knows it's going to lose money on that sale. It just has to sell it, according to the current rules of the TCC auction and the way that the TCCs are financed.

You could say that, "Yes, if we had sufficient competition among individuals in the TCC auction, we could think that every TCC would be fairly priced," but I think that's just really sort of

a bridge too far. We've got these tens of thousands of products, and to expect that we could have maybe 50 market participants that could figure out exactly how to price these things, given that a vast majority of these market participants really have regulatory issues with playing in the market for many of these TCCs... In particular, one of the things we saw in the case of New York is that a significant amount of the TCCs that the traders are purchasing are essentially from generation node to generation node. If you were an electricity retailer, you'd probably have a hard time explaining that to your regulator, or just explaining, in general, why you're purchasing that kind of asset, except just simply to earn a profit on the fact that you bought it low and received more payments than you made. But the downside would be quite consequential for you with your regulator, and with maybe perhaps your management and shareholders.

So, a possible solution, and this is just to get the discussion going, is, let's keep FTRs, let's keep the periodic auctions, but essentially FTRs should be funded by a willing counterparty, not the ISO. How would this work? Well, the way it would work, I think, would be quite simple. And here's where I think there's a value judgment that you need to make, and so I'll make my value judgment quite clear. My feeling is similar to Speaker 2's in the sense that this merchandising surplus is the property of the entities that pay for the transmission network. And the people paying for the transmission network are loads. So why don't we just give loads the merchandising surplus according to their hourly share of total system load? This is the current approach that many of the ISOs use to essentially allocate over a collection of losses back to loads.

I think that some allocation scheme like this would certainly be fine. And this would mean that larger load in more congested areas would get more of the merchandising surplus. I think this would get Speaker 3's idea of the market portfolio of FTRs--allocating back to a market

participant their share of the merchandising surplus is basically giving them a portfolio of FTRs. And so one interesting question again for future research is, would allocating back to load something like this give them a very effective hedge against the congestion risk that they face? I think that's an open question, but certainly one worth analyzing.

And then all market participants could participate in periodic FTR auctions. But all of the FTRs purchased and sold, would be from, essentially, willing counterparties. So anyone that wants to could participate in this auction, just like how any other derivative market works. So when I sell a forward contract, if I sell a forward contract, there's got to be another willing counterparty on the other side taking that position. There isn't someone who's forced to sell me a forward contract at whatever price that I'm willing to pay for that forward contract. I've got to find a willing seller.

Again, because there's a network model we're trading through, it doesn't need to be that there's a counterparty. The counterparty to an FTR that I have could be composed of many different counterparties selling or buying different FTRs from different locations in the grid.

So just to kind of give an idea of what this might look like, as I said in the NYISO, all the FTRs (at least the FTRs that are loads) only sink to load zones. And so one of the things we did is just say, well, what would it be like if what we did is we said, let's take the average TCC payouts for all TCCs that sink in that zone, be they a generation node or a load zone, and this gives the distribution of the monthly payouts by sink zone of the TCC. And this gives, essentially, the load shares by zone, and there's a fairly good correlation between the dark shades in one and the dark shades in the other (the western part of the state being an exception), but, you know, if you did this sort of simple *pro rata* allocation of the merchandising surplus, you'd provide pretty much the same level of refunds of the congestion

charges, and then, for those who want to buy the hedge, they can go buy that hedge in any of the auctions that operate. For those that want to speculate, they can speculate too, but they've got to speculate against somebody who's intelligent, and someone who really disagrees with them, rather than just simply the ISO, which can indefinitely fund FTRs that are losers, by virtue of the fact that it can fund them out of the merchandising surplus.

So that's the basic point, which is that is limiting ISO funding of FTRs, I think, just makes life so much easier for the ISO, given that you don't have to worry about revenue inadequacy, you don't have to worry about the thinness of your markets...It sort of takes care of itself. By refunding the merchandising surplus, you're sort of giving people a market portfolio of FTRs to hedge their congestion risk. They can then purchase and sell relative to that market portfolio to tailor what they want to the specific locations that they are purchasing generation at or serving load at, and then generators and traders with superior knowledge can continue to earn money in the same way that they already have, but they've got to do it against a willing counterparty, relative to the ISO and consumers. Thank you.

Question: Speaker 4, on your slide when you showed the number of TCCs that had one participant or one bidder, are those point-to-point TCCs?

Speaker 4: Or point-to-load zone. Just all TCCs.

Questioner: Right. So, do you think that might be a little misleading, given that a number of the TCCs are so related to each other?

Speaker 4: I don't think it's misleading. I think I was quite straightforward about the fact that you're competing through a network model. But still, it's just to point out that you've got a huge n for the number of products, and you've got a very small number of firms that are competing for those products. And –

Questioner: Do you have similar data on the number of bidders by congestion element, instead of by points? I think that would be pretty revealing. Then you'd show a lot more competition. That's what I was thinking.

Speaker 4: And I would guess that that's why the retailer is getting what they're getting. In other words, on the congestion elements, certainly, there is adequate competition.

Question: I had a clarifying question. I think Speaker 2, you had on your page nine an example of the allocation only taking up a certain portion of the total capacity. I think that was meant to be, obviously, just an illustration, but my clarifying question is, why is the allocation such a small amount of that capacity? It relates to Speaker 1's comment, also, that it looked like the allocation payments were some 55%, I think, of the total. Why is the allocation not much larger, if it's commercially valuable? Is there something structural that prevents the allocation from essentially taking more of the capacity?

Speaker 2: Again, this is just an example. I think some of the major paths would obviously be fully occupied by allocated FTRs. I guess this is an example of those paths which are not fully used up by allocated FTRs.

Questioner: I guess the question is, if there was excess capacity, and that capacity's just essentially not allocated, what is the reason why it's not allocated? Is there something preventing that from sort of not being allocated to customers directly, in the process of the typical allocation? I know that in PJM the allocation is much, much higher. There's a much larger total capacity allocation than what you had – I think the combination of Scott's data and your example there suggests a much lower allocation in California.

Speaker 2: I wasn't trying to suggest anything data-based with that example, but, yeah, in

California's ISO allocation, load-serving entities are limited to allocating to sinks at their load nodes. And I have no idea how California's allocation process is different from the allocation process in other ISOs. I just know that the example I put up there applies to any market. In any market there are going to be constraints in which the full amount of that constraint is not used up by allocated FTRs. And, for me, that's where the flaw lies. You can then set a limit in the auction above the values of used up allocated FTRs, then that quantity is precisely the quantity which the ISO is forcing rate payers to offer at a zero-dollar reservation price and results in inefficient transactions for these hedges.

Speaker 3: Can I also just add something to that, because I think one of the concerns if you try to do that is that you have the potential that all of a sudden you've created a new constraint or limit which is how much did you allocate in the auction, and all of a sudden, if that's not a commercial constraint, that's now going to bind in the auction if somebody's buying a different path. And so that becomes a phantom constraint in the auction that now other people can arbitrage, and it creates very potential for even more inefficiency. So just something to think about.

Question: I also have a question about page nine in Speaker 2's presentation. So, we're talking about the same numbers. The part that is offered at zero is labeled as counter flow. The part to the right of the limit (above the line limit) I understand has to be from counter flow, but the part to the left of the limit is just flow.

Speaker 2: What this picture's trying to show is that there isn't a difference between what's offered to the right of that dotted blue line and the amount that's implicitly offered by rate payers at zero dollars to the left. Both of those (and I'm sorry I didn't get to those points, I felt a little rushed for time there), counter flow explicitly offered by entities bidding in to sell counter flow and then the leftover amount on the constraint, those both create opportunities for entities who

want to buy FTRs over that constraint to buy FTRs. The only difference is the price at which those FTRs are being offered by the entity which is selling them, right? So, for the amount that's to the left of that dotted blue line that's being offered at zero, others can come in and buy that, even if the highest bidder is one penny, but then the counter flow being offered to the right of that dotted blue line, that's being offered by willing counterparties who can actually put a reservation price on it. So those both to the left and to the right of the dotted blue line represent the sales, the offering of FTRs in the direction of flow. It's just the only difference is the price at which they're being offered.

Questioner: But there's a fundamental difference between the left and the right of the line limit. To the left, the congestion rents are available to cover the costs of it, and to the right they're not. And so you have to come up with your own money for the counter flow part to the right. So they're different ideas. I don't think counter flow is important to your argument. The argument is about zero.

Speaker 2: Well, I may have been calling it counter flow, everyone calls it that. I'm just making the point that these are the same things. These are both financial swaps being offered.

Questioner: No, they're not the same things.

Speaker 2: I understand that you're saying the difference is that the amount to the left is supported by congestion rents.

Questioner: It's called capacity.

Speaker 2: That goes back to one of the earlier arguments I made, which is that you're then implying that because rate payers then have these congestion rents, that that somehow puts an obligation on them to then offer these financial swaps at a zero-dollar reservation price. And my point is that those congestion rents belong to them. They shouldn't be forced, because they

have this asset which they own by paying TAC, because that's what they own, they should not then be forced... Just because they have that asset, should they be forced to sell these things? I think that's the point of debate.

Questioner: Well, "capacity compelled to be implicitly offered by rate payers" would be an accurate description of your argument. And "counter flow implicitly offered by your rate payers" is not an accurate description of the argument. And I think the two different descriptions don't have anything to do with your argument. I just think it's a conceptual problem.

General Discussion.

Question 1: When I managed a futures market, we worried about three risks: price risk, credit risk and liquidity risk. Price risk is you trade forward in time, credit risk is they better be there to pay you, and then liquidity risk is being able to get in and out of the transaction. When I think about FTRs, the way I think about it is that you have the day-ahead congestion that's going to be collected. And that'll be collected in the actual day-ahead markets as they evolve, and ultimately get paid the ARR holders or the transmission right holders, but, because this is a floating price risk for them in the future, you insert FTRs in the middle. And the FTR is simply then giving a guaranteed fixed payment to the ARR holder, and the FTR holder is going to accept the risk of whatever the variable price will be. If it's short, and there's not as much collected, they pay whatever that gap is to the ARR holder, and if it's excess, they get to keep it. But because they're being inserted there, they're accepting the price risk dimension. And so, because they're accepting the price risk dimension, there's value in that. There's value to accepting that risk. And so, because there's value in that, I would always expect that the amount that the FTR holders receive from the day-ahead congestion would be greater than the amount that they're guaranteeing as fixed payments to the ARR holder, because if there's no gap there, then there's no value to that

risk management service that they're providing. There must be value.

So when I think about some of the slides that Speaker 1 showed, talking about the gap here, and Speaker 2, you were talking about how FTR payments must converge to day-ahead in theory, otherwise it's not working, I would say, "Well, wait a minute, they've got to be gapped, right? There's a value risk premium." So, should there not be a risk premium dimension to this? Shouldn't the amount collected from the day-ahead not equal the fixed amount of the FTR, because there is a risk benefit being provided by the FTR holder?

Respondent 1: I don't understand what you're talking about.

Questioner: Really?

Respondent 1: I don't understand what you're saying about the value and the risk.

Questioner: So, the FTR payment is a fixed payment, because that's the amount they sort of agreed to, so that's the amount that ultimately gets paid to the ARR holder.

Respondent 1: The auction holder, yeah.

Questioner: So the FTR person who's sitting in the middle is accepting that risk if in fact the day-ahead congestion is less than the FTR amount that was agreed to up front in advance, or they get the extra payments if in fact the FTR amount was lower than what the actual day-ahead congestion is. So they're playing a risk management role. That's what the hedge is all about in the middle.

Respondent 1: Right, and I said that if it's a load-serving entity that by taking only that FTR reduces their risk, you'd expect them to be willing to pay a premium, just like I pay a premium for my fire insurance policy.

Conversely, when it's a risky financial instrument and I'm buying it for return, I expect to get a positive return. I expect the return to be greater than the price, and that's the dichotomy I was making between, is this being sold as a hedge, or is it being priced as a risky financial instrument, or is there something else going on? Because we'd have something wrong with the model.

Questioner: OK, but because you're selling a hedge, you would expect that there would be some premium there that would have to be received by the FTR.

Respondent 1: I'd expect that the FTR buyer would pay a premium in order to hedge his position. That's what I was talking about.

Respondent 2: I'd say that there is a difference between a load-serving entity that receives an allocated FTR, or an ARR, and that then willingly sells that back in the auction process, there's a difference between that and what I was talking about in my presentation, which is load-serving entities, rate payers, being forced to sell the leftover capacity on a transmission constraint after the allocation process. So if a load-serving entity receives an allocated FTR, and they want to sell it back, then they can say, "You know what, I'm risk averse on this payout that I may get from this defined point-to-point ARR allocated FTR that I have." So, yeah, they'd be willing to sell it at a discount to the expected payout. That is not the case for that pool of congestion rents which are left over after the allocation process. That's a pool of congestion rents which are then going into the FTR balancing account. So, for all rate payers, all load-serving entities, as a group, I view them as actually being risk averse to what is the sale price in the other direction, right? Because, you know, for them, there's uncertainty, because they're being forced to offer that at a zero-dollar reservation price. They have no idea what the auction numbers are going to be. They have no idea what the congestion rents are going to be. So I don't think they would be willing to

sell that at a discount. So do you see what I'm saying? I think there's a difference between –

Questioner: You're saying there's a separation between the elements that you're thinking about, in your mind?

Respondent 2: There's a separation between the allocated FTRs a load-serving entity willingly sells and puts a reservation price on versus these FTRs that they are being forced to offer by the fact that the FTR auction is based on the limits that the ISO expects the transmission system to have in the day-ahead market.

Questioner: If you're forced to offer it, do you also have, since there's open access, the ability to then be on the other side, so that you offer it but then you could buy it at a price, or at least bid in a way that would raise it to a rate that you think is reasonable?

Respondent 2: Sure, sure, but if there's a whole bunch of load-serving entities, and like Speaker 4 talked about, the current design is kind of forcing rate payers and load-serving entities to sell all these FTRs, and so then to expect them to go back in and kind of defensively buy them and kind of figure out what is the value of these things, I think that's not something that can be expected. I think the financial entities that are making the most money off of these things have a huge incentive to pinpoint all the discrepancies and the profit in obscure locations of the network. I don't think it's realistic to ask every single load-serving entity to go in and try to defend all those positions.

Respondent 3: I did understand your question. I thought it was a pretty good one. Yes, there are market participants who are looking for a risk premium for participating. There are also market participants who are generators who are looking for a hedge, in some cases. They might be in the same location as a market participant who's a load that's looking for a hedge, and if they're at the same location, they both can't pay a risk premium. One's going to be higher than the other,

relative to the prices at that location. I think the issue is that you have open access, which is providing the market for everybody.

If Speaker 1 did his example with PG&E instead of PECO, he would get a very different conclusion than the one that he's come up with, and the issue within the PJM market is that the pattern of ARRs from the grandfathered rights to the load-serving entities happens to flow over certain constraints that tend to constrain PECO more than it constrains the southern path within PJM, and so there's probably a bias.

This is a level of detail that's completely unnecessary, because it's not that complicated, but, yes, people do expect a risk premium, and people do hedge, and all of that is creating a public policy benefit by having the ISO facilitate a market for different market participants to manage their risk and relate to what then happens in the forward market.

Respondent 4: In any sort of futures market you can get a risk premium or a risk discount, depending on whether the buyer or the seller is risk averse or risk neutral. I mean, I agree that there are certainly products where I think it's certainly possible that there can be simultaneously products bought as hedges and products bought as speculative, and you can certainly have those two outcomes.

So the first question that I would ask is, should the ISO essentially be taking this merchandising surplus and essentially be saying, "We're going to create these products that are essentially risky assets that people are going to buy because they're risky assets, and then we're going to fund them with money that we could instead refund to rate payers?"

I think that's really what's at issue here, and my feeling would be that if we're going to do that, then I think what we have to do is say, "Well, part of the reason that we're willing to do that is because we think there is some accompanying

market efficiency benefit associated with that.” The one that I can think of is the fact that these entities that are taking the so-called speculative positions are providing counter flows through the network for the physical players that are willing to purchase hedges, and they’re getting larger hedges as a results of the counter flows that these financial players are providing. And the economic benefits that are being created by those counter flows exceed the cost that we’re paying to those financial players from the fact that they’re getting more back in revenues than they paid for the CRRs that they purchased. So that, to me, is the big question on market efficiency. Is that really what’s going on? Is the reason that we see that for certain market participants because of just a transfer, or is it because they’re essentially expanding the size of the pie?

Question 2: This question is about the liquidity risk issue. There were a number of discussions by the various panelists about the willing participant concept. But in the ISOs, one thing they do which is unique, as opposed to other futures markets, is they match the other side. And one of the advantages of that, when you have so many different generation nodes and centers, is that it provides liquidity, because one of the dilemmas is that if somebody wants to trade a generation node, to go out and find a bilateral party is going to be difficult. They’re going to have difficulty. You go to a broker. The transactions get done, but they’re harder to do, and then you may end up paying a higher price premium. That risk premium may even be higher, because now you’re paying a liquidity premium as well. The auctions, to me, are beautiful systems of handling that issue with the ISO on the other side. So, any thoughts about liquidity management? If you move to a willing counterparty approach, we have to have buyer and seller match, as opposed to the ISO.

Respondent 1: Well, my argument is that you keep the auction, that’s for sure. It’s just that you don’t force the consumer to sell the effectively unused capacity that’s unallocated at any price.

My argument would be that you give it to the consumer, and the consumer gets the price that he wants. He sells it, and then essentially what that means is that effectively all CRRs or TCCs, all FTRs are essentially financed by the counterparty that sells it, but the auction mechanism is still clearing everything. And so it works exactly the same way, it’s just that capacity gets freed up by the fact that someone is willing to sell something that creates capacity for someone else to buy something. And at the end of the day it nets to zero, so the ISO and, *ergo*, consumers, aren’t on the hook for anything left over. It’s just that the guys that are negative pay the guys who are positive. But it’s still true to the auction mechanism.

Respondent 2: I think that the liquidity is really, really critical. And if you’re going to do what Respondent 1 is talking about, which is just having willing counterparties but net to zero, you’re not going to have transactions. You won’t necessarily find people willing to match up. I think Nodal Exchange tried at one point to have an ISO lookalike that would just be willing counterparties, and it quickly devolved into the zones, which Nodal Exchange may still run, I don’t know.

You have to also think about the generators as also one of the physical market participants in here that are not getting allocated these rights at all and are having to go buy them, and it’s important in the market for them, or for a financial participant who’s providing a hedge to a generator, to be able to access that kind of liquidity. And the problem with the willing counterparty element is that you have a bank, maybe Macquarie or Goldman Sachs or Morgan Stanley, they’re financing wind power plants getting built in ERCOT and elsewhere, and what they’re doing is they say, “OK, but you have to hedge with us and we’re going to give you a contract for several years on this particular project.” But the price that they would get at those locations would be potentially prohibitive. It would definitely be higher if the bank actually

didn't have an FTR auction to be able to know that they were going to be able to go and have a liquid price and be able to buy contracts at that location. They wouldn't be able to finance that wind plant in the same way without the ISO providing the public benefit of the liquidity that goes along with this system of LMP, which is the only one that works for competitive markets. So it's all tied together that way, and that's why it's really important that there be these products available.

Maybe you can think about it as spectrum. The government auctions off spectrum in order to create a market, and there's a public benefit there. And, yes, it goes to the rate payer in that the value is assigned to the rate payer, but sometimes they might get it to the auction, sometimes they might get it through their ARR. There's a market mechanism for doing it, and yes, they are profitable when you look at it.

One of the things about these markets that's interesting is that they're more transparent, in some ways, than almost any other of the financial markets that are out there. I mean, when the Senate did the investigation of the banks in 2014, they released a report that talked about how Goldman Sachs made \$3 billion a year over five years with 60% returns, and that was common among many of the banks for their participation in commodity markets. Well, I don't know. According to the analysis that we're getting from the economists from the ISO, this is too much profit. And I don't even know if that's a relevant question in a competitive market. I mean, the question should be focused on the model discrepancies between the day ahead and real time, which Speaker 1 has identified, or on whether they are over allocating. Those kinds of things are the right questions in order to make this work better, but it's not who's too profitable, because that's not competition.

Respondent 3: All I'm saying is that there are two ways you can think of running a market. It's just about where the initial conditions start. What I'm

simply saying is you first allocate all of the portfolio of FTRs to all the market participants. They've got them. And if they want to sell them, they can sell them. But the difference is that now, under the existing market, they *must* sell them. And that's the only difference. It's just about the fact that certain FTRs will not transact unless there is someone willing to sell that specific FTR through the auction mechanism. So it's actually no different from the existing auction. It's just that there won't be the forced sale as a price taker. That's the only difference.

Respondent 2: But that's essentially what PJM does with this ARR market structure, I believe -

Respondent 3: No, it's not.

Respondent 2: ...they allocate the ARRs, and then you can buy them back, so it's -

Respondent 3: That's different.

Respondent 4: Adding somewhat to what Respondent 1 is saying, this liquidity that Respondent 2 mentioned that's created by the current auction--it's a forced liquidity. It's not like this liquidity is being put out there and it's a free resource, right? There is a counterparty providing that liquidity, and it's the transmission rate payers. They're providing the liquidity, and they're losing a lot of money because they're being forced to provide that liquidity.

There are other types of markets for these hedges. But they aren't going to develop when there are all these hedges being offered at a zero-dollar reservation price. So I think what we would like to see is for ISOs to implement basically what Respondent 1 is suggesting, and then other markets can actually have a chance to develop.

I think there are other innovative ways that risk can be pooled so that liquidity can be provided on these kind of hedges for basis risk at a low price. At DMM, we've put out one paper in November which kind of suggests one way that you could do

this through trading hubs. I think prices which are based on an average of generator prices create a natural buyer and a natural seller. People who have a higher price than the average, they're a natural seller of the hedge, people who are at the lower price in trading hub, they're a natural buyer of that hedge. So I think, basically, the current auction design is stifling innovation. It forces liquidity, with conscripted sellers of that liquidity, and they're losing money because of it.

Respondent 3: Respondent 1 and Respondent 4 talked about how we're going to allocate transmission rights to the consumer, but we're not. The rules are going to allocate them to the dominant transmission owner, so the DMM/Southern California Edison proposal will actually allocate the CRRs to Southern California Edison (SCE), PG&E, and SG&E, and then they will be able to sell it. And DMM already said they have regulatory incentives not to sell it, so they won't sell it. And if they don't ask for it, no one can buy it.

In the slides I didn't go through, I listed all the entities I found that got CRRs from the hub to their load. Now, that's great, but in order to buy, the other guy has to be able to get to the hub with an FTR. Under the SCE proposal, unless SCE gives it to them, the community choice aggregator won't be able to transact with anybody, because none of his counterparties will be able to get an FTR to the hub unless he decides to sell them, but if SCE doesn't sell it or doesn't nominate it, there's no way to get it. But they can pay a premium in order to buy it from the generator.

So that's my reservation about this. I think it is fundamentally inconsistent with open access, but there's a balance here between selling it for zero and saying that it's not going to be available at any price. And that's the line I'm trying to tread here, to keep open access, but on the other hand we don't have ATMs that when you push for \$300 it gives you \$30,000. And that's a market flaw, too.

Respondent 4: But that argument assumes that the only entities who could or would sell the hedges for basis risk are the entities who receive the congestion rents. That's not true.

Respondent 3: They've got the natural edge. Do we have a rule in foreign exchange markets that we can't buy from the people who have Marks? Maybe we ought to do the same thing for the utilities, then. They can buy, though. We'll just give them the congestion rents, and they have to buy all their hedges from the people who are taking the naked risk.

Respondent 4: Well, because LSEs, in receiving the congestion rents, could be natural sellers, that does not make them the only sellers. And, again, I think what we're talking about is whether there are other mechanisms, other financial products, which can create in other ways natural sellers of these hedges for basis risk? And I think there are.

I guess the other point is the idea that the IOUs will be the only ones who receive these congestion rents... I mean, I think what we're talking about is that the congestion rents, just like they're allocated now, they're allocated on a pro rata basis, you know, so the smaller LSEs would also receive their shares –

Respondent 3: But the smaller LSEs want to buy at the hub. So they need the liquidity from the generator to the hub, whereas Edison, in rate base, you know, they buy at the generator and then they take it to their load. They don't need to trade at the hub. They're not in that market.

Look at New York. There's a lot of trading by the load-serving entities, and in Speaker 4's paper, one of the problems is that he looks at the load-serving entities, where you see a lot of the smaller ones aren't on that list, because they buy from the traders. They count on the trader to hedge, and then they sell Zone J, and the small LSE buys a Zone J hedge for the summer. They don't want to do all the stuff of buying the TCCs and the

counterparties, and that's what gets killed. And if you have an ICE forward market or a NYMEX forward market at a trading hub, you don't even know who's on the other side. The LSE can buy, but the other side has to be able to lock in their risk. You look at Speaker 4's list there. I see companies he's got listed under "traders" that I know they're doing physical. I know the NYISO, and I went and talked to one of those people about their FTRs in another context, and they had it back to back with a long-term contract with an LSE. So if they can't get the FTR, well, guess what happens to the LSE? It's not able to hedge.

Respondent 2: So, just two very quick comments. First, Respondent 3, I'm giving you your LMP Evangelist card back that I thought you might have lost earlier, so thank you. And, second, I promise Respondent 1 and Respondent 4 that if their proposal goes through, their rates will not go down a penny.

Respondent 4: So, I think I meant to open up my presentation by saying that we're not arguing that there isn't value in having a liquid trading company in which these forward energy contracts could be contracted. I think there's value in that. And certainly there is value in there being some kind of market for hedges for the basis risk between an individual generation node and those trading hubs. Our point, DMM's point, is that the FTR auction mechanism, it's a flawed mechanism for providing those hedges, and we think there's a better mechanisms that can be developed. And the current FTR auction design is stifling those mechanisms from being developed, because there's no reason for these other mechanisms to be developed, because there are all these free hedges being put out there by rate payers.

Respondent 1: That's, exactly, by the way, what Enron argued in the 1990's, right, Respondent 3?

Respondent 3: The Southern Company would've loved this approach that you don't need to have

open access, you can just find someone else to sell it to you. But –

Respondent 2: It's a cheap shot whenever you mention Enron, but I heard at one of the previous sessions that whoever mentions Enron first wins, so... [LAUGHTER]

Question 3: Thank you. I have a point to make, and that is that the FTR auction, I think, is one of the auctions in which all the participants in the auction are truly on an even playing field. The other auctions or markets that are put up, that are available through the ISOs, actually really don't have that even playing field anymore. You have various aspects where people have market power, and other physical constraints that typically create barriers to entry and so forth, but in the FTR auction, broadly speaking, all the participants are on an even playing field.

And the other thing is that it aggregates various types of participants, so, obviously, financial entities, traders and so forth, as well as the physical entities, are all essentially participating, and participating fairly vigorously.

I also want to point out that the FTR auctions are very transparent. All awards are made public--in some instances made public immediately, or, in the case of New York, at the conclusion of multiple rounds of the auction. And there's also a very large amount of transparency in the way the auction's conducted.

So in some instances you could argue that this is the poster child for competition. I know, Speaker 2, you specifically said this is a non-competitive market. It was on page four of your presentation. My question is, is it non-competitive, or is it just that you don't like the market outcome? The market outcome being, of course, that some participants, like ourselves, put a lot of investment in management and valuation and tools and so forth to be successful, particularly in valuing FTRs, and therefore, if we don't make a profit here, we have to go home and choose a

different line of business. We're no longer in business anymore. And so we have to actually make a profit in the same environment. And is it just the outcome of the market itself you don't like?

Respondent 1: And so you're saying that auction participants are truly on an even playing field? So let's say that's true for half the participants, right? The buyers, half the market, are on an even playing field. Our issue is that the sellers are conscripted sellers. They're being forced to sell these hedges, or offer them at a zero-dollar reservation price. That's not a market. It's not a market.

Respondent 2: But it was found money in the first place. I mean, it's an artifact of the LMP market design. I mean, when it was vertically integrated, you were building generation away from load. I do agree that allocating transmission rights to the load-serving entities is the right answer, but I'm also sympathetic to the wind plant over here that says, "Hey, you know, this LMP system is really awful for us, because we're getting hit with a lot of congestion charges." And there's a balance between those two factors.

So my view is that when you have a system where the ISO is allocating the rights to the market and the entrance point is very competitive, and the load-serving entities are getting the value from the auction in a market like PJM where they can choose to participate, they can choose to do a contract with the DC Energy, they can choose to reconfigure, they can choose to just take the auction rents, it's up to them, it all seems to be working well. That seems to me to be the right balance. The problem, I think, that Speaker 1 has identified, which is the right problem, is, are there some modeling issues with the auction that create these money machines, and can we minimize those? So that's the bathwater. Let's try to limit that. And what's frustrating is that California ISO and California ISO staff isn't focused on fixing those and how they can do that. They've started

to, recently, but they are more focused on, let's just get rid of the competition.

Respondent 3: I think your point's spot on, in the sense that the one question that I've continually asked myself is, "Look, there's free entry into this business, and so therefore why isn't this sort of rent being eroded?" And one argument could be that it is the appropriate rent for essentially providing the service that traders provide very well.

And so that is a good question as to why we're not getting rent erosion. I think Respondent 1 provides one answer to that, but I think you can then dig in deeper and ask the question, "OK, you are making that money from the FTR process. Is there a commensurate benefit that you're providing to the operation of the market?" And I think that's the open question that is the point of debate. As a result of the many purchases that are being made that don't look like they're going from a generator to a load-serving entity, are those still providing economic benefits to certain market participants that essentially justify those revenues in terms of that social cost benefit calculation? And I think that's the big question, at least for me, that is still up for debate.

But it is a puzzle, in the sense that you go, yes, I take your point exactly. Others could come in and try to erode those rents, and they haven't. What's the barrier for that occurring? And it doesn't look like there is one, but then, on the other hand, we want to ask that second follow-on question of, "OK, as a matter of regulation this is happening. Is the cost worth the benefit, so to speak?"

Question 4: At the end of the day, we really care about what forward price they are buying at. And Speaker 4 suggested that, maybe they could contract out, and they would then get the congestion rents allocated to them. But one of the issues there is that the congestion rents, even if they were allocated them, probably in the periods where they need them the most, they probably do not cover all their risk, I think the forward market

allows them to actually buy a full hedge, rather than a partial hedge. Speaker 4, how would you address that?

Respondent 1: Exactly the way I say it. You should have an FTR auction. I mean, think of it as giving people the money. Now they're getting a flow of money. That money flow is going to be a refund of the aggregate congestion revenue. You're not giving them FTRs. You're not doing anything. The market will then create the point-to-point FTRs that everybody needs to serve their load. So –

Questioner: That's not the point I'm making here. They're not being able to buy their forward power. I think we're getting caught up in this small piece of the energy market, which is congestion rents, but it's really the whole energy price. And they can't go into the market, because traders and generators don't have an FTR market to participate in. Who's going to sell them –?

Respondent 1: Why not? If they continue to run the auction, they can buy it in the auction.

Questioner: But you're taking out the natural capacity of the auction.

Respondent 1: Not necessarily. My bet would be that if there are a lot of hedgers out there who are willing to pay more than the actuarially bare value of the asset, there'll be lots of guys willing to sell that hedge. So, if you're willing to pay more, there's somebody on the other side that's going to sell them that, I would certainly guess. I would bet DC Energy would do that. They would make a consistent profit providing that hedge.

Respondent 2: So how is that different from what PJM does with ARRs?

Respondent 1: The difference is that all you're getting is a share of the merchandising surplus. You're not getting any ARRs.

Respondent 2: You're just getting a share of the surplus –

Respondent 1: Just the money. Just money.

Respondent 2: And so then you're still having a bilateral market with 1,300 points in PJM that the ISO runs an auction for, where they have to match the exact quantity of buyers and sellers at each of those 1,300 points in order to have an auction that's actually liquid. It's so far-fetched. It just doesn't work that way. That's why what happens in the auction is you take the transfer capability, the ISO ensures that it's revenue adequate pretty much everywhere but California, and auctions off that system capability to the market, and then people can then reconfigure into the ones that they need that meet their hedging needs.

Respondent 1: They can still do that.

Respondent 2: But in your theory, you're saying that you're giving them the money, and then people can then go and voluntarily participate in an auction where you actually have to have exactly one for one buyer and seller at each of thousands and thousands of locations.

Respondent 1: That's what you have now.

Respondent 2: No, because there's transfer capability that's in the auction –

Respondent 1: That would be built into the auction. That's the way it works.

Respondent 3: The fundamental thing is that if you take the huge pool of rents and spread it per megawatt hour across the load, that has no relationship to the congestion risk on a specific path. And that's a huge wealth transfer, and I and Bill Hogan and Susan Pope went through the negotiations in New York, and Con Ed rate payers were going to get the benefit of the transmission system they paid for to deliver power into Con Ed. They were not going to give

it to upstate New York. That was a non-starter. That would be a huge wealth transfer.

It's not ARRs, it's called ETCNL, which is Existing Transmission Capacity for Native Load, and it's built in to the auction that specific dollars go to specific rate payers as a credit against their Transmission Access Charge, and they do not want to give it to someone else who is not paying that Transmission Access Charge. So saying that we're going to spread it out over the whole state is just, A, a cost shift that makes it a non-starter, but, B, OK, you've now got it spread out all over the state, then it becomes enormously risky to say, "OK, I've got one ten-thousandth of the congestion rents for the state, now I'm going to sell a hedge into New York City." That's not correlated. If you do a correlation of the payment on an FTR from Zone G into Zone J, that isn't going to be correlated with the overall congestion rents in New York.

Respondent 1: I think we should do it. That's another one I think...

Respondent 3: OK, well, why don't you do it and come back.

Respondent 1: I would love to. I would love to.

Respondent 3: It's all public.

Respondent 1: My only point is, is who gets the merchandising surplus? If you make the decision that says that's the property of load, then why don't you give it to load? But if you don't, then there's certainly another way to go. But if the premise is that that's the property of load, then it does seem to make sense to give it to load. And then, I agree, figure out how you should give it to load in a fair way, but that's what regulators do. I don't think that's a hard thing for –

Respondent 3: That's what regulators already did.

Respondent 1: So I think they could do it, no problem.

Moderator: So, obviously a topic of great interest. [LAUGHTER] Let's maybe then proceed to the next question.

Question 5: The problem that I have with this notion of limiting the FTR auctions to willing participants is that that is going to have a very detrimental impact on liquidity. There are just simply too many nodes out there, such that there are just not enough people that are going to participate in those markets. I mean, we see this in other energy markets. If you drew the parallel back to simplest energy, crude and gasoline through natural gas, in the crude and gasoline markets we have relatively few basis points and we have very deep, very liquid markets. When you get to natural gas, there's a lot more basis locations, and suddenly there's a lot less liquidity. Gas markets have been struggling with liquidity for years. You move to electricity, and suddenly, across all the ISOs, the number of basis relationships blows out exponentially. So I think that assuming that you're going to have this huge pool of participants is just really not realistic. So I think that's something you've got to consider very carefully.

If you look at the financial players, there are at least two broad categories. There are definitely those people that trade, they take risks, they provide a very valuable service to the market, but they are taking a lot of risk. The ISO is not taking risk when they're the counterparty to these FTRs. All they're doing is they're basically facilitating the credit transfer. The other broad category is those financial players that are intermediaries in the market, where we might be providing financing, hedging, all kinds of other financial products that are not in the ISO market. So these are kind of the broader market impacts. So my question is, when you're doing your analysis and you're looking at how things are affecting pricing and the like in the ISO markets, how are you considering the externality of the futures markets, the OTC (over-the-counter) bilateral markets, the

impacts of funding your projects? How is that being brought into that analysis?

Respondent 1: The way we're looking at it is we're trying to estimate which of the CRRs that are currently purchased in auction are likely to be supporting forward energy contracts. And those are CRRs which are between node delivery pairs, you know, gens and trading hubs, exactly the kind of transactions that we're talking about. And so in those CRRs we have the data. We can see exactly what their willingness to pay is in order to have that hedge. And so, looking at those CRRs and seeing what their willingness to pay is for those hedges, we can get an upper bound on how much and what would be the costs if these forward energy contracts go up. And in California it's not that much.

I think that the argument that you guys are making about liquidity, that's a valid point right there. There can be an efficiency loss if the cost of buying a hedge go up, then load-serving entities buying at a trading hub would then potentially face the decision of paying a higher price for the forward energy contract at the trading hub, or going and transacting at less liquid nodes, like generation nodes. And so, you know, there is a potential loss there. In California we're looking at it. It's pretty bounded. It's not that big. It's not big at all compared to the amount of losses we're seeing on CRRs that are being auctioned off and that are clearly not supporting forward energy contracts.

And so, especially in California, if you do the kind of auction that Speaker 4 and I are talking about, would everything fall apart? Would the prices skyrocket so much that it's not worth doing? What we're estimating is, no. And so we think it's a step that's worth taking, because we're confident there are other ways, and we think that innovative financial companies can come up with other products which can enable these hedges to be transacted at an efficient price.

Respondent 2: Using the parallel to other futures markets, as you rightly said, futures markets disappear. And the reason they disappear is when there aren't willing counterparties to take the other side on the market. And I tend to think that's what we'd like a market to do. When both sides do not see something that's mutually beneficial, it ceases to exist. And you could argue that if we ask consumers in California, "Do you think there should be FTR auctions?" I suspect they would probably say, "No, we'd like that money back that is being paid out." And that's, I think, the point that Respondent 1 is making. They would probably say that we're OK with there being less liquidity in these FTRs, because that class of FTRs have been persistent losers.

And so that's where I'm coming from. I certainly want liquidity at the places where there are willing buyers and willing sellers for transactions to occur, because therefore we know that both sides would benefit.

Respondent 3: Yeah, so when there's less liquid market the risk premium is higher and the cost to the counterparties to those transactions, if they're selling to, say, a retail load in PSEG, is going to be that much higher because they don't have access to the FTR market, so those prices will go up. So I can tell you that if nothing happened and you then refunded all the FTRs to consumers, I suspect the bills would change not an iota.

And if you actually eliminated these markets, OK, I think you would end up seeing the prices actually go up, but not knowing why. And that's one of the things about open access and non-discrimination in competitive markets. When they're not there it's very hard to see the impact of them not being there. And that's why it's so important for the FERC to kind of defend these basic principles about open access and non-discrimination and how these markets are designed.

Respondent 1: I think you put that well, but you're talking about open access. But just before,

you were talking about prices going up. This isn't about open access. This is about prices potentially going up for some LSEs who may currently transact at trading hubs. And that's a maybe, right? So some of these –

Respondent 3: I'm hearing it from the banker.

Respondent 1: Well, even some of these smaller LSEs who transact to trading hubs, they're getting allocated a portion of these losses. So the question is, is the amount of losses they're getting allocated, is that more than the increase in transactional cost for moving from a trading hub to actually transacting at a less liquid generation node? That's one question. And that's the worst-case scenario. That's the worst-case scenario, in which no other market for these hedges develops. And I think that premise is just wrong. I think there are other markets that are going to develop.

Respondent 3: I think that if the ISO fixed the model discrepancies, which does create a lot of leakage in the market, they would get a lot of the benefit that they're looking to get without eliminating the market. And they could also ensure that they didn't oversell the system.

You know, it was interesting moving from being a consultant to actually working in the market and seeing how things are traded and how the market actually works. It was quite an education for me. When I first went from being a consultant to actually working in the market, in the early 2000's, the entities (I won't use the E word – but say Morgan Stanley, Goldman Sachs), these companies selling origination deals, there was a tremendous market for Super Bowl tickets, trips to Vail, really expensive steak dinners with the load-serving entity, and because of the lack of liquidity and transparency in the market, those people who work for the companies basically would do a deal, and it was "prudent" based on the fact that there was less liquidity in the market. So they wouldn't even see the higher prices.

As these markets have gotten more sophisticated and people start to learn how to use the FTR markets, the FTR markets have sort of disciplined the forward markets. Where there's a contestability there between the FTR markets and the forward markets, the risk premiums have really gone down, and the prices in the forward markets much better match the expectation of what prices are going to be in the spot market because of that competition, but it is very much due to the liquidity and transparency you get. And so you don't really see nearly as many customer boondoggles as you used to.

Respondent 4: There's a willing buyer and willing seller, but a willing buyer and willing seller at the trading hub are only there if some people have access to the monopoly transmission system. Don't lose track of the fact we're talking about the monopoly transmission system. And open access and LMP is all designed to give everybody access to transmission systems so we can have willing buyers and willing sellers as some people said at the liquid trading points.

I view this proposal as eliminating the willing buyer and seller, because the only seller will be at Southern California Edison, or it'll be the person that has to take the complete naked risk of the congestion. So we're eliminating most of the willing sellers. But, on the other hand, I agree that it shouldn't be an unlimited loss, and there's a point where we have to look at how these markets are designed and whether we are running the auctions right. Are we having excessive payouts? The market that LMP replaced in PJM was competitive, but it was horribly inefficient. So you can have competition, and you can still have a market that's got flaws that need to be fixed, so I'm in the category of, I think there are some things that need to be fixed in some of these auctions, but I think we have to preserve open access and the ability of everybody to buy and sell at liquid trading points.

Question 6: So, there are many different concepts floating around here that are, I think, a little bit

confounded, and I would like to sort of parse this out a little bit and then get down to a question.

So, a couple things that we would all stipulate. First, financial transmission rights are a brilliant innovation. [LAUGHTER] Secondly, selling more capacity than you have is probably not a good idea. Thirdly, selling a whole lot less capacity than you have is probably not a good idea.

So we've got a problem here, which is this managing the derating story, and the things that Speaker 2 talked about, about how the actual conditions will be different, and that's a real issue. We want to maintain revenue adequacy, and we'd like to have some consistency between the models that are used in the auction and that. And that's not a trivial matter to do, but I think that's important. But I would like to say we don't disagree about that.

Then there's the question of who should be the beneficiaries of the congestion rents on the system, and my lawyer friends advised me that there's a well-established legal principle that they go to the transmission owners. And now we have regulations sitting on top of that, and I think most of us in the room would stipulate that the regulators will say the benefits should go to the people who are paying the transmission charges, which is the load.

Then we come down to this question of how do you deal with those transmission rents and this capacity, and the idea of just allocating the congestion rents by some sharing mechanism across the system – this was actually an idea that was vetted at length in New Zealand, for example – and when you look at it for a little while, you come to the conclusion that Speaker 1 came to, which is that it socializes the allocation, and it produces congestion rent allocations that have nothing to do with the risks that people are actually facing, so it undermines that market and that doesn't work. So that's not a good idea, and we should stipulate that, if we haven't.

So maybe we want to allocate something to the loads which is related to the actual problem that they're going to face, which is hedging congestion, and that's the allocation of the rights. And I think there's a general agreement here that having an allocation of the rights to the loads is a good idea, and that seems to be one of the proposals. Now, I point out that allocating the rights and spreading the congestion across are mutually inconsistent ideas. So you can't do that, but you can allocate the FTRs or CRRs or TCCs, if you want, to the various folks, and you shouldn't allocate more than you have capacity, but you'd like to have it relatively matched to something they would like to have.

And then we come down to the idea that we're going to have an auction that Speaker 4 is going to run which is going to set up such that people have now got these allocated rights, and now we're going to run the auction with these allocated rights, and people can buy or sell if they're willing to do so as willing buyers and willing sellers. And Speaker 3 said that this is essentially what they do, and that's the theory of the auction revenue rights in PJM. And you can buy back, yourself, if you want to. I think that is equivalent. I think those are essentially the same thing, so that seems like an appealing idea.

The idea of auction revenue rights was to get over the problem that we had perceived, which was what Speaker 1 has been talking about, which was that, well, SCE or whoever, it just isn't going to offer them for sale if you don't do it, because they're either acting like a monopolist or because they're a couch potato or whatever. I don't know, but you put the rights in and you have to sell them, but you can buy them back, and so if you put it in and you buy it back and you win, then you got it for your reservation price, which is exactly what we want, and so everything works like that.

So I don't think that would be a bad system, for California to adopt the PJM model and do a good

job of allocating the auction revenue rights, and for all the entities to buy and sell those rights in the auction, and to sell off everything, but they could buy it back, and that's the same thing as putting in a minimum price to sell it. I think that's a very good idea.

Now, here's the question, and here's the problem which I think everybody is missing. If you did that system, and you ran that auction that Speaker 4 was talking about that we all think is a good idea, (and you follow the rule that if you give a transmission example you have to have more than two locations), and if you put it in a network, you will find that when you do the allocation and then you do the sale and you get reconfiguration of the auction because people want slightly different patterns than what ended up in the allocation, then you're going to get things that look like I'm selling stuff that wasn't offered before, or that wasn't allocated before, because it wasn't in the original configuration. That is just unavoidable in the network. It's just the simple mathematics. And what I hear as an undercurrent is that that would be unacceptable. We can't do that. We can't let people buy things that haven't already been allocated point to point. We can only do the ones that were actually allocated, which then restricts you down to a particular way to use the grid, and then you lose a lot of efficiency and all these other kinds of things. And I think once you go down that path, you'll find that you're going to be very unhappy with that particular outcome. So my recommendation is to adopt the Speaker 4 model, but do it the way they do it at PJM, and then go home and have a nice dinner.

Respondent 1: One of your premises there is that selling less capacity than you have is a problem.

Questioner: If you allocate the capacity rights to somebody who is a monopolist and wants to just sit on them, and where doing nothing is the same thing as putting in an infinite bid for the capacity right, you're going to have a big problem. And that, in fact, will be your real problem. I don't think this is conjecture. And it's the flip side of

the problem of making them put in a bid at zero, which is just the flip side of the same story.

So the way it works in PJM is where you allocate the capacity to them, but it's an auction revenue right, so they have to sell it, but they can also put in a bid to buy it back for, say, \$23. If the price turns out to be more than \$23, they're in effect selling it, and if the price turns out to be less than \$23, they hang onto it, and that's fine, but they have to proactively put in that bid of \$23. They don't get to sit on their hands and do nothing and make the bid look like it's infinite and foreclose access to the grid. So that maintains open access to all the FTRs, it maintains an allocation of the rights, it maintains the ultimate flow of the congestion rents, it ends up with the load-serving entities that got allocated the auction revenue rights in those proportions, but it does not eliminate the observation that the configuration of rights when you get done will be different than the configuration of rights when you got started, maybe by a lot. And if the notion is the only thing we can do is live with the rights that we allocated in the first place, then you're greatly restricting the flexibility of that marketplace. So I think PJM has basically got it right, in theory and as it was described here, I'm not going to go into all the details of what PJM does, that's another thing with...I think that solves everybody's problem, but it doesn't eliminate this observation which I consider to be not a problem, which is that you're selling rights that weren't allocated, because they exist implicitly in the grid. You can't avoid it.

Respondent 2: You're selling available transmission capacity, which is what FERC wanted us to do. Didn't we have open access, and ATC had to be made available? As a matter of fact, it used to be on a first come, first served basis, wasn't it? So isn't an auction better than that?

Respondent 1: I'm not arguing about the allocation process. I don't see how the allocation in the California ISO is functioning differently than the allocation process, the ARR process,

through PJM. It's just that there's a difference in what the default action is. But everyone still has the same options, the same –

Questioner: I don't think that's correct. And your examples are showing this. What PJM would try to do is allocate all of the capacity (though it's impossible to do this exactly in a grid). There wouldn't be any leftover capacity, and then they would have an auction. And then the people that were allocated the capacity, if they wanted that capacity, could put in a bid to buy it. And then when they bought it, they would get the revenues from the sale of the capacity they just bought, and if it was the same thing, if it matched perfectly, then it's just a wash, and they got the capacity that they wanted.

But if they want something different, then we get a reconfiguration of the whole system, which is good, because there's all kinds of other possibilities that would be more efficient in matching all these kinds of things. And that's fine, but it produces pictures like in a multiple node version where it might be seen as, "We used to have 600 megawatts of transmission rights between two and three, and now we have 1,800 between one and three. Where do those other 1,200 come from? There must've been somebody ripping us off." And the answer is, no, it's just reconfiguration of the capacity rights involved there.

Respondent 2: To just take your point closer, to say if I had an ARR from A to B, then all you'd do is take PA, PB and you'd give me the 50 that you allocated me A to B, even though that was not what was ultimately sold.

Questioner: For allocated A to B, you sell A to B, and you buy what you want. And if you want A to B, you buy A, B. That's it. And everything works. It works just fine, and you don't have to go through all this other stuff.

Respondent 1: OK, but that's the allocation process, right? The ARRs are still allocated point

to point. And so in a full network model you can't allocate out all the capacity. All the capacity cannot be allocated out.

Questioner: Yeah, real life, right? And you also can't solve the reconfiguration problem if you don't have an auction that allows reconfiguration.

Respondent 1: Sure, and I'm not arguing that. What I'm arguing about is that leftover capacity on the constraints after the allocation process. It's what's left over after the allocation process, because you can't allocate all of it out. If there wasn't anything left over after the allocation, I absolutely hear what you're –

Questioner: Yeah, but you're making the mistake, you're making the mistake of assuming that what people want is going to exhaust every possible constraint that will ever develop.

Respondent 2: No, I think he intends to withhold it.

Questioner: He wants to withhold it, right. But you can't allocate it initially at all of those values. And now what are you going to do? And there'll be a big political fight over the ARR allocation, you know, and that's complicated. We had the business solution in New York, where we would do it a certain way to make sure that everybody came out the same. I can go through that if you want, but in the end, from an economic efficiency point of view, I don't care. They can assign them randomly, as far as I'm concerned.

Respondent 1: So what you're saying is that, OK, so the leftover capacity after the allocation, the CRRs get put into the FTR balancing account. And so what you guys are arguing is that rate payers, through LSEs, should be forced to auction off the rights to those congestion rents, because if they don't then they're somehow withholding that transmission capacity? I think that's the argument you're making – and again you're assuming that the people who have the congestion rents are the

only ones who can sell these hedges....I agree, the prices may go up.

Questioner: That's a red herring. Unfortunately, I have to say it, that's an Enron red herring. So, you know, that's true now. Anybody can sell point-to-point rights now. What we're talking about is the existing capacity of the grid. Suppose you didn't allocate anything, and then you said OK, now we're only going to have the auctions of point-to-point rights, then the capacity of the grid would be irrelevant, because everything would net out, and so you wouldn't be auctioning off the existing capacity of the grid. You're trying to reduce the capacity of the grid that you're allocating to the marketplace. That's, in effect, what's happening here.

Respondent 1: So, it's not reducing the capacity of the grid. I think you're conflating the congestion rents with –

Questioner: No, you're reducing the capacity of the grid in making the sales of FTRs.

Respondent 1: You are, I mean, so –

Questioner: Yes, you are. There's just no avoiding it.

Moderator: Let me suggest this. I really think the questioner had a great suggestion, and maybe it's the solution, and maybe we can all go to dinner. I suggest a deeper discussion later this evening, and we can delve into this, because I'm worried that there are several people who have questions that we don't have time for. So let's go through rapidly these questions.

Question 7: I'm just going to make a couple of observations here real quickly. First, I congratulate the people who designed this agenda, because it just occurred to me that in the morning the problem was, how do we get money to generators, because there's not enough incentive for them to stay there, or how do we get enough money into the system? In the afternoon

we're worried about how to take money away from people that are providing hedges, and it worries me that the afternoon proponents will be more successful than the morning ones, and I fear it will lead to a gradual degradation of competition in the market. But a brilliant contrast.

The first comment was on the returns information. Fundamentally, it seemed like there is angst that is created is by the sense that, "There is so much money earned by people who have these FTRs, there's something that should be done about that," and of course the counter balance is liquidity and having an efficient market. And, on the return side, it's hard, for me, from looking at this data, to see the compelling rationale or data behind that. I looked at, you know, what one would've made in the S&P investing from 2009 until today, and you'd have done just as well as what you've been making in CAISO over the past couple of years, looking across all the FTR contracts that were bought. So the returns can be very episodic, and it's hard to judge how high or how low they should be, given the risks that are associated with them. So I'd just be real cautious about what that means and the selectivity that goes into it.

On the second part, with liquidity, there is a huge benefit to that. I kind of echo what Speaker 3 had said, and the crazy thing for me is that, when I look at other commodities that are sold, typically, sellers love an auction. That's what they really do best with, is having an auction. Unless, of course, it's broken, and of course if you don't have enough willing buyers and sellers in the auction, then it will break. The issue that came up about whether there would be enough people on the willing side, to do it, was something that was experimented with, as Speaker 3 pointed out, with Nodal, and it wasn't effective. So I think we all know where that would go. And the buyers typically don't like auctions. Buyers typically would rather have an illiquid market, and I use the name of the company that did that so well, but that's what one would see the return of, is things like that.

So that was observation two, which leads to the third issue, which is I think a number of people pointed to in the design issues, and I wasn't clear from what all the speakers said, whether or not this is a CAISO-specific issue or whether it's a broad ISO issue, certainly if it's a CAISO-specific issue, it seems like a design solution is the way to preserve most of the benefits while not having the problem. And one has to just worry that competition won't be aggressive enough (but I've never had that experience) to be able to drive prices to a very fair level. So it would seem, then, that if it's not a general ISO issue, it's a design issue, which then goes back to the discussion that unfortunately my question just interrupted, which was on the path of how to address that in a way that would be far more effective than trying to take pieces out of the marketplace in hopes that in the end you'll have a more effective outcome.

Respondent 1: I think what we're getting at there is that there's a tradeoff, right? What I'm saying is that the current auction design is forcing rate payers to offer that extra capacity at a zero-dollar reservation price, and you're saying that the other extreme is that if you don't do that, then those entities will be allowed to withhold it, right? So, I mean, I think that sounds like that kind of tradeoff. That's the dynamic they were talking about that we're disagreeing on.

Comment: There's a middle ground.

Respondent 1: Right, and what I think the middle ground is is to allow there to actually be a market, right? It's the people who have the congestion rents. PJM is not different. The excess capacity on the constraints that isn't doled out to the allocation, that's still being auctioned off, offered at a zero-dollar reservation price.

Respondent 2: But there's something magical about that extra transmission capacity and what is auctioned in the FTR auction, and people act like the ISO is just having this random auction. No, if the ISO's doing it right, they're doing something

quite magical, which is matching what they auction off with the actual physical transmission capability on the grid. And if they do that, they never have a revenue inadequacy problem, and they're providing the liquidity for people to reconfigure these products into what meets their individual needs.

And I think the current questioner has a really good point about the returns, because if you were to look at the returns on FTRs as a problem, you would identify January 2018 and the polar vortex in 2014 as horrible years for these willing sellers of FTRs in PJM, because prices spiked, and all the FTR holders who were long made a lot of money, and the FTR market was very, very profitable. Well, it was exactly at that time when the load should be really, really happy with the standard offer provision. So, you would see that the returns for the people who sold the hedges to the load are really bad when it's really cold, at the same time that the returns to the FTR holders (which are taking advantage of the load-serving entities, according to Respondent 1), are also really high. So there's a balance there. It's exactly what it should be, right? You can't say that the FTR holders are making too much money at the exact same time that the loads are like, "Thank God we're hedged."

Questioner: I just don't think we'd be having this discussion if the FTR revenues in CAISO weren't, as Respondent 1 perceives it, too high. And, I don't know, maybe they are, but I think you really have to look first across all the ISOs and ask the question, is this a systematic issue, or is it a CAISO alone issue? Because if it's CAISO alone, deal with the CAISO alone issue in way that PJM has, or someone else. If it's not, if it's a general ISO issue, I don't see the data that supports it.

Respondent 1: I think we see it in MISO, we see it in PJM, we see it in New York ISO, we see it in California ISO. So the four largest ISOs have had this issue where rate payers are losing money

from these auctioned FTRs. So it is a problem that's fundamental to the design.

Questioner: So you would have nobody who sells insurance, as Speaker 1 says, have any income from that, systematically, over time.

Respondent 1: I don't think that's what Speaker 1 is saying. I mean, the issue is that financial entities are taking advantage of the fact that rate payers are offering this at a zero-dollar reservation price. They're not selling insurance. They're just buying these financial swaps that are priced lower than the expected payout. That's not insurance. If it's an actual hedge...like Speaker 1 pointed out, there some nodes, some paths in PJM, there's some in CAISO, too, where they actually are hedges, where generators are paying more than the expected payout. It's working well there. It's all these other constraints. It's all these other kind of small constraints or conflicting constraints in the corners of the network model that I think financial entities can take advantage of in the current market design.

Question 8: This discussion and financial transmission rights are premised on the assumption that the transmission system is fixed and inflexible, and that assumption is no longer true. I previously worked at ARPA-E, which, by the way, is going to get a budget increase, hopefully, in the federal budget, which is great. We can cautiously celebrate at dinner.

A number of years ago, the agency funded research into a number of advanced transmission technologies that have now been fully validated, or are commercially available or starting to get deployed. Three that come to mind are dynamic line ratings, so you can dynamically change the effective capacity of a line based on the local temperature using line sag sensors. A second one is power flow controllers, so you can physically change the amount of power flow that's flowing through a line, either by changing the impedance of that line or effecting the phase angle. And the third is topology optimization. You can use,

basically, math to figure out the optimal topology of the network and leverage Kirchoff's laws to redistribute power flows pretty much in real time. So the combination of those three technologies can essentially relieve congestion up to 50%, and can be done in pretty close to real time. So given all of that, I mean, what's the future for FTRs?

Respondent 1: But all those things we already do. The New York ISO does that re-optimization. We make assumptions in the auction about a certain level of optimization which is conservative, and one reason why they don't have shortfalls is that that re-optimization in the day-ahead market, relative to the assumptions in the auction, produces surpluses. So all of that fits in with the FTR framework, and it's just the choices you always have to make of how conservative do you want to make what you sell, and then, by re-optimizing better than those assumptions, you generate rents and surpluses in the day-ahead market that then get allocated back or reduce the shortfall. So I think the framework's perfectly capable of accommodating that, it's just a matter of taking that into account and making reasonable assumptions in the auction model.

Respondent 2: There's no question that actually if you look over time there have been a lot of transmission upgrades that have taken place in the last ten years. Investment in transmission, and also lower gas prices, have reduced, basically, the dollar values in the FTR auction. I agree with Respondent 1 that some of these developments can be internalized with the ISO, but all those should be increasing transfer capability, which would be solving some of these problems. I think one of the problems that's very particular to California is the way they use nomograms for the operators to determine...A previous questioner gave the example of "We had 1,800 and it went down to 600, and where did all the transmission go?" Well, that's what the operators are doing within California when they have outages. Rather than just running security constrained dispatch or doing the types of solutions that you want, and I don't want to judge, I definitely want them to be

reliable, but they should use the model to try to manage those constraints. And if the constraints were similar between the day-ahead market and the FTR auction, or the CRR auction, you'd have a lot less of the type of leakage that Speaker 1 is worried about, and you probably would have somewhat less profitability from the CRR auctions. And in PJM, I concur with one of the previous comments that the constraints that bind in the auctions match pretty well the actual constraints in the day-ahead market. There are always going to be some differences, but it's a good predictor. And in California it's really not a good predictor, because they just haven't done a good job of having those two line up.

Respondent 3: But rate payer losses in PJM from auctioned FTRs are still larger than rate payer losses from auctioned FTRs in California--on a per megawatt basis, I'm not sure, but on a total basis.

Respondent 2: So, when you measure rate payer losses you're looking at January 2017 and saying FTRs in PJM were so profitable, that was probably the most profitable month ever, at the same month when the rates that consumers actually have to pay were probably one of the highest in terms of electricity prices. But, you know what, all that was bought through retail markets and standard offer service, so when you say that it's a rate payer loss, it's not a rate payer loss. It's the market design that is allowing competition. And California could use a little bit more of it.

Question 9: I have a very fundamental comment. And that is that the transmission system we have today is 99% paid for by rate of return regulation. And that regulation assigns responsibility for the cost of capital to customers. Those customers bear downside risk if that transmission is not used at capacity, and therefore my question is how do all these mechanisms help those customers have any upside in their investments?

Respondent 1: I would say that customers are benefitting, because you're basically having a least cost dispatch that the ISO is running, which is resulting in really low electricity prices, and that is because you don't have the rights being use them or lose them, like under the old model. You converted physical rights to use the grid into financial rights, and that's what allows the whole nodal pricing system to work. So you can't look at FTRs as this isolated market design element, where we're going to measure who's profitable, because I've got a PhD student who could go look at data, but he can't look at whether Macquarie's making money off its hedges to the wind plants. This market is working really well for the customers at the end of the day. You know, the level of rent seeking that's taking place from gencos that are concerned about how low the prices are for customers is getting to be extreme. So I would say the market is working really, really well and this is an essential part of that market design. It's part of the LMP system.

Respondent 2: So, this is the center of the debate here. We were measuring the losses to rate payers from this auction mechanism in one way, and I think what Respondent 1 is talking about, and other people are talking about, is that if there was no auction, and this worst-case scenario was that there was no auction and no one selling hedges, then would some of the forward contracts for energy, would those prices go up? Yeah, some would, but the debate is, how much would it go up, in terms of the debate about whether or not this current auction design is something that should continue, or whether or not we should look for something completely different.

And, again, in DMM we are trying to look at both sides. And so we've put out data on the one side, and we are working on now putting out data on the other side. And our initial analysis is that the amount that these forward energy contracts would go up is a lot less than the losses from these auctioned FTRs in California. And in terms of –

Respondent 1: Until you run into a problem when they're not hedged.

Respondent 2: No, no, no, because the analysis we're doing is that we're using the actual CRR bids, the bids from CRRs which does reflect what the market's generators are willing to pay for these hedges. We're looking at exactly what the value of these hedges are.

Respondent 3: Right, but that's their willingness to buy the hedges. It doesn't mean that if they couldn't get the hedges, they'd stay in business. It might be that if the CCA can't get those hedges, they don't grow. They go out of business. So I don't know that you can say that that measures the value. It says that's how much they're willing to pay in the auction.

It's good to do these studies, but I want to get out also, you know, Speaker 4, when you talk about New York, Long Island Power Authority is not a generator. It's the largest load-serving entity and utility in New York, now that there's retail access. So when you do these analyses –

Respondent 4: Come on, come on, enough, OK? I mean, really. We gave clear definitions as how he classified generators and financial participants and the like. If you own generator assets, he called you a generator.

Respondent 3: OK. So SCE should be a generator, because they own generation assets?

Respondent 4: Yeah, he classified financial participants as people who don't own generation. Generators are those who own generation/load-serving entities. I mean, come on.

Respondent 3: Right, OK. So now we know your analysis has nothing to do with the returns to retailers or regulators or generators, because you've got the largest load serving entities in the generator category.

Respondent 4: I don't think that conclusion is justified at all.

Question 10: I don't understand why you don't adopt the PJM model. Let me explain the way it works. You paid for the transmission system, so you get ARR's. But it's competitive, so load serving entities get the ARR's. We then have the opportunity to keep them as FTR's, or actually we are arrogantly smart enough to think we can trade them and make some money on it. In return, we turn around and hedge our customers. Those residential customers, our business customers, don't have this savvy that we arrogantly think we have, and the information's transparent. If we're doing something stupid, we try and figure out what Goldman's doing or someone else is doing, and then we change our behavior. But the bottom line is, we're giving our customers the value of a lower fixed price, because we think we can take these tools and go into the market and hedge appropriately.

And I guess you've stumped the band as to why you don't accept the ARR/FTR model of PJM. There have been modeling challenges about underfunding and overfunding, but that's a modeling issue, not a fundamental market structure issue. And, in fact, in PJM we've just voted to ensure that excess FTR revenues go back to ARR holders. It's doing the right thing. So you've stumped the band. It sounds to me like you've got modeling issues, because the market structure fundamentally works in PJM.

Respondent 1: I'm not critiquing the ARR model. Under the SCE proposal, right, it would be the same in CAISO as it would be in PJM. The ARR allocation process happens, so you could still set the limits of the constraints in the PJM auction equal to the flows that would occur if all the ARR's were self-scheduled. So my issue is, what's left over on the constraints, on top of what's used up by allocated ARR's or FTR's.

Questioner: I think you're not connecting the allocation issue, right? It sounds like – and maybe

it's because we have competition and you don't, I guess that's maybe what the fundamental flaw is, but I'll stop. I'm not a Californian. [LAUGHTER]

Moderator: I was going to say we should probably wrap up. But what I wanted to say is that we had a lot of good, thoughtful discussion. I really appreciate what all the panelists brought with their talk today. A good robust conversation here. It does seem like spending some time

tonight at dinner getting deeper into that, just so we understand exactly what they're talking about, I think would be helpful for everybody, because we all share the same goals. What we're trying to achieve here, I think ultimately it's a matter of trying to figure out what's the best way to do that and look at other models, so hopefully they'll result in productive discussions for everybody.

Session Three.

The State of State-Federal Jurisdiction in Electricity Markets: Is Policy Coherence Possible?

Joint federal and state jurisdiction over electricity has been an issue since the Attleboro case and the subsequent enactment of the Federal Power Act. While there has been a general shift in the direction of federal authority, flashpoints arise in clashes in policy viewpoints between regulators/policy makers at each level. We may be at such a crossroads today. The list of issues is lengthy. They range from resource choices, where states may have expressed various preferences (e.g. ZEC's, RPS and other renewable preference, and DOE's, and various state efforts to support nuclear and coal), demand side options (e.g. DR, DSM) to externality considerations such as carbon. The Clean Power Plan represented an exercise of federal, although not FERC, authority over electricity markets. The limited federal powers over siting makes direct conflict between state and federal authorities on those issues limited in a direct way, but still fraught with contention indirectly, as siting authority can be used in ways that thwart policies in regard to resource preferences of the federal government, or even of neighboring states. The recent New Hampshire decision to reject the Northern Pass line, for example, thwarted, at least in the short run, Massachusetts' effort to obtain non-emitting hydro resources from Quebec. Setting up a carbon price in regional markets, particularly in those regions where states that have carbon policies that differ substantially, poses not only difficulties among states, but would also complicate any federal effort to oversee markets with a carbon price. Even without a carbon price in RTO markets, differing carbon policies in states inevitably impact federally regulated wholesale markets. There has also been an evolution in case law over the past few years defining the scope of state and federal jurisdiction. There are numerous other examples, but the big question remains what is the legal situation in regard to the jurisdictional powers of state and federal authorities, and how does that play out in terms of the coherence of electricity markets in the U.S.?

Moderator.

The line between federal jurisdiction and state jurisdiction over electric service has been fairly well understood for over 80 years, since the enactment of the Federal Power Act in 1935, or, if you prefer, for over 90 years, since the Supreme Court decided the Attleboro case in 1927. With some twists and turns along the way, the rules were pretty straightforward. The federal government, now acting through FERC, exercised jurisdiction over rates in terms of service for wholesale sales and transmission of electricity in interstate commerce. The states had all the rest--retails rates, distribution rates, siting electric generation and transmission facilities. For most of those 80 or 90 years, the system worked tolerably well, perhaps because most of the regulatory activity took place at the state level. Utilities were vertically integrated, and most customers, whether residential, commercial,

or industrial, bought all of their power needs from the local utility at rates regulated by the state commissions. Federally regulated wholesale and transmission transactions took place, but they were largely peripheral.

That all began to change in the late 1970s with the adoption of the PURPA, and we found ourselves in a very different situation. In some regions, including those with most of the nation's people and economic activity, FERC-regulated RTOs and ISOs provided regional transmission service and operated the wholesale markets. And even if most customers still buy power from their local utility, that power was often generated by others and sold in FERC-regulated transactions. So, what is subject to FERC regulation has greatly expanded, and some would argue that state authorities, in turn, find their traditional levers of power over local utilities to be less useful than

they were in the past. Meanwhile, concerns about global climate change have grown, and many states are seeking to promote resource choices consistent with their policy preferences while still ensuring the right resources to preserve reliability.

So, the fundamental question before us is this. Can the octogenarian scheme of divided jurisdiction over the sectors of the electricity system serve the public interest in the very different circumstances that we find ourselves in today? That question, and those that flow from it, will be the focus of this particular panel.

Speaker 1.

Obviously, tensions between the states and the federal government are as old as the republic, and there's no reason to believe they wouldn't happen in this area, given the complexity of the regulatory scheme within which we all operate. And if you don't think it's complex, then just try explaining it to anyone who's not in this world--the RTOs and FERC and the states and the Federal Power Marketing Administrations--and they just pretend they have to go to the bathroom and never come back, once you start even trying.

I think there are three primary drivers that are exacerbating this federal-state tension right now, and I'll talk about the three of them, and then really spend the rest of my introduction on the third.

The first is technology. With the growth of so many technologies that are connected at the distribution level or behind the meter, both supply technologies like storage which can be supply or demand, and also demand technologies, those technologies, collectively, can operate like a central station wholesale resource. So, this is coming out in, for example, the FERC storage rule that was issued a couple of weeks ago, or maybe it was last month, as well as the distributed

energy resource topic that FERC has a two-day tech conference on next month.

The second big reason is issues around siting and control of property and land. Of course, siting has never been easy. Back when I first started doing this in the '80s, I thought it was hard. I don't think I knew what hard was, and maybe I still don't know how hard it's going to be in the future, but siting any sort of energy infrastructure, whether it be generation, transmission, or pipeline, seems like it's become more difficult. And at a time when the nation, of course, is going through a transformation in power supply and needs a lot of linear infrastructure to facilitate that--transmission and pipelines--they have to cross places to get from population centers to resources, especially the location-constrained renewables. It's just become extraordinarily difficult.

There's any number of examples. The Clean Line will be the subject of articles forever because of their effort to build HVDC (high voltage direct current) across multiple states and always running into at least one state that didn't want them. In New England, my own state of Massachusetts is trying to execute a law that was passed a couple years ago to buy large amounts of renewable energy and is running into a siting battle with New Hampshire on their first-choice resource. Of course, there are the pipeline cases in New York, and we could go on and on. So, that's really exacerbating it.

And the third complicating factor is state desires to choose resources, even in states where the states were part of the change to a reliance on a regional market for resource adequacy--New England, New York, and some of the PJM states. What we're seeing increasingly is even in states that broke apart the utilities and moved to a competitive auction and mandatory structure for their resource adequacy and went to a merchant

model, states are wanting to select resources, whether to subsidize resources that are not thriving in the market, or to buy new resources that might not be the ones the market selected. This has been a problem. It's not a brand-new problem, but I would say it's been exacerbated since November 2016, because, with the federal government stepping out of the climate arena, you see states and even localities amping up their climate focus. Now we have 22 states with carbon goals. And so, that's making them go their own separate ways, not expecting federal leadership, and we're addressing the problem the first name of which is usually "global," right, "global warming" or "global climate change," with a solution that starts with state or local. What could go wrong? But that's where we are, and that's not going away, as far as I can see, for this presidential administration, and by then, the states will have been well into this path.

So, how is this playing out at FERC? Obviously, the RTOs and ISOs we regulate are facing the challenge of adapting their wholesale markets to state policy initiatives. It's no secret that I'm an enthusiastic supporter of competitive energy markets. It doesn't matter how many articles Travis Kavulla writes and Ari Peskoe tweets in the middle of the night that I read and I think are great, I still really believe the markets have done a good job for customers, compared to what was there before, in the regions that they exist in in promoting innovation, promoting efficiency, deploying resources over a broader footprint, and keeping costs down. But I am well aware, since I lived through it, that the markets exist through the choices of the states—the good will of the states who chose to change their structures and rely on a market, particularly in the regions that do it for resource adequacy. And with the states making so many of their own choices, the real issue we're facing is whether the markets can satisfactorily adapt and be sustained through this challenge.

My former colleague, Tony Clark, has written articles saying, "Choose a lane. You're going to be a market, be a market. You're going to be regulated, be regulated. No mixing. Choose a lane, and then we won't have this problem." He's right, of course. The problem is, nobody gave me the authority to put people in a lane. And even when we had our big two-day hullabaloo on the markets last year, and the states were before us, no one raised their hand, not even New York, and said they want to take back resource adequacy, other than for the specific resources as to which they want to make the choice. So, therefore, we're still left with how to keep the lights on so things don't fall through the cracks between what the states are doing and what the regions are doing.

This tension was expressed in the ISO New England CASPR (Competitive Auctions with Sponsored Policy) docket, which, as I said, FERC voted out three weeks ago. For any of you who don't live, eat and breathe this stuff, it basically was a proposal that the ISO New England constructed primarily in response to efforts of New England states to specify and contract for specific new resources. It didn't address subsidization of existing resources *per se*. It was all about Massachusetts and other states wanting to buy large amounts of new resources that would not necessarily have been selected by the market in a price-driven system. And what ISO New England designed was like an adjunct to their capacity market. After they run a capacity market in which the subsidized resources are excluded by a minimum offer pricing rule, they run a substitution auction and use an auction to decide which of those subsidized resources will replace which of the existing resources that might take extra money to retire and give their capacity obligation to the new subsidized resources. Clear as mud, right? But actually, given the problem they were facing, I liked that it used a market to decide who got the allocation, and without

suppressing the price to the people who were not getting subsidies.

So, this was not an easy decision, necessarily, to bring it all together at FERC. But an advantage of having the deadline and getting the order out is that different commissioners took the opportunity to express their views on these things, and for all of you who've been wondering why some of the other orders didn't get out, FERC saw a range of different views. When FERC had the tech conference, there were five paths. Path one: no minimum offer pricing rule; let the states do what they want and the market will figure it out; let 1,000 flowers bloom. Path two: adapt the markets to accommodate by repricing, or something, so that you can have some market resources, some subsidized. Path three: status quo, fight it out. Path four: redesign the market, like with a carbon price, so it chooses the resources so the states don't have to go around the market. Path five: MOPR everything; have a market; stay in your lane; forget the state stuff. Those were the paths.

Well, what we saw in the separate statements from the commissioners is that there was little of path one. There was little path five. There was no path three at the commission, but I just recently met with a whole bunch of PJM stakeholders who said, "Please, please, leave the status quo." So, I guess now all of the paths are spoken for.

I believe that the benefits of market are sufficiently strong for customers. Just look at what's happening in the West, by the way. (Another whole Harvard topic.) It's worth the effort to try to come up with a design solution. Then you just actually run the market without workarounds and actually build the state goals into the market, if the states will agree with their goals and allow the market to solve it. But it can work to a "just and reasonable" level, in my view, if it's designed in a way that allows the subsidized

resources to come in and still protects a market price for non-subsidized resources.

I strongly supported CASPR. My priority was saying yes, because I thought they came up with a just and reasonable proposal, and I wanted to send a signal to other regions. Hey, other regions, come up and come in with your regional proposal. So, New York is working on a carbon price. Very exciting, potentially. And PJM is working on a multi-headed hydra of several different options that they will put before the Commission. I shouldn't call it a hydra. It's FERC's job to make these choices and make these decisions, but PJM is filing several different proposals, one that is a two-tier pricing capacity repricing, and two that are some version of a minimum offer pricing rule with various exclusions. But debate is healthy. Starting to confront these issues is very good, and, as some of you might have heard me say many times, having been on FERC, I've served with 11 different commissioners, we are not the Beatles. We did not grow up making music together, so we just kind of flick an eye and the other person starts and the harmony continues. We are the Monkees or the Spice Girls. They found us each individually and locked us in a room and said, "Make music," OK? So if you hear some drum solos and all, I mean, we're just trying to learn to make music together. We've only been together since December, and we're going to have a lot more opportunities. So with that, I'll stop and await your questions.

Questioner: I was kind of surprised and wanted to make sure I heard right. You said PJM is filing three proposals. The only thing discussed in the stakeholder process was the PJM proposal, the status quo, and then the MOPR-Ex. You're saying they're filing something different than that, that never went through the stakeholder process?

Comment: We can clarify that. At this point, PJM is looking to file the MOPR proposal, as well as the capacity repricing proposal. There was some discussion about whether we would try to do some hybrid of those. We may signal that there's certainly options for that, but at this point (and this has evolved), we don't want to complicate this filing (it's complicated enough) with yet a third option or fourth option or fifth option. So, it's been a little bit of all of that.

Speaker 1: I'm sorry. I stand corrected.

Comment: In fairness, keeping up on this is hard, because there's a lot of internal discussion going on. We're still putting it together. Thank you.

Question: When you started out your talk, you mentioned that there were three developments that are exacerbating federal-state tensions: technology, siting, and then state desire to choose resources. And then you had some discussion about ways to at least approach or resolve some of these issues. But you didn't talk about any ways to approach or resolve siting. I'm wondering why you omitted further discussion of that.

Speaker 1: I think that if we truly want to make changes, they probably would be legislative, such as the backstop transmission siting that Congress was going for in 2005 that later kind of fell apart in the courts. The stage we're in now, I think, is a lot of really outlining what the limits are of different jurisdictions, which will clearly go to the courts and give Ari and you more to write about.

So, in the pipeline example, one pipeline came before us, and we said "No, New York didn't act within a year." That was waived. We are going to say they can still build, even though New York didn't give the clean water certificate, because it was waived. Another one came and said, "Oh,

give us that, too, we want that," and we said, "No, in your case, New York did act within a year, they extended it and acted, but you refiled," and then now there is a third case pending that raises a somewhat comparable issue. Each of those cases is going up to the courts, in some cases to two courts, to the Second Circuit on something the state did, to the DC Circuit on something FERC did.

So that will be getting at least to understanding, if New York can step on the hose, how they have to do it to make it stick legally. I don't know.

We heard from a pipeline the other day that had legislative proposals to change the Clean Water Act. I wouldn't expect them to pass, so I think we're just going to try to work with the laws we have for now.

Obviously, I could say, "Let's all get together, be one big happy family, decide about things." Some of the things that work, if you look at things like CapX2020 in the Midwest, the companies brought local munis and coops into the fold to help them get siting. There are kind of workaround proposals, but as to the jurisdictional tension, I don't have a solution.

Speaker 2.

Good morning. Thank you for the invitation to be here. I wanted to just begin with sort of my mindset when I think about state-federal tensions. I don't really sit in Columbus, Ohio, thinking about what my turf is, versus what my federal colleagues' turf is. It's just not something that I think that we think about or discuss much at the Commission. Now, of course, it naturally becomes an issue with some of the cases that we have to adjudicate, but I wanted to get that point across, because I think that there is, in fact, tension between states about this whole federal-state tension piece and how much attention needs to be paid to it.

I have a number of conversations with our national association, NARUC (National Association of Regulatory Utility Commissioners), about this argument, or issue, associated with jurisdictional concerns. And I sometimes admonish our national association for constantly bringing up the jurisdictional concern without really digging into the meat of what is actually being proposed and what the actual impact would be for customers.

Let me give you an example. So, I started representing NARUC at the NERC MRC (North American Electric Reliability Corporation Members Representatives Committee) about three years ago. And the tenor at that point in time was just to be very guarded about all things potentially jurisdictionally problematic for the states. And I started to sort of peel back the layers of this. I thought to myself, well, be careful what you wish for, because I don't think that the states are equipped to handle some of the reliability issues that you may think cross the lines between federal and state jurisdictional boundaries.

And so, what I'm trying to espouse with our national association, and also with some of my state colleagues, is, let's be a little more thoughtful about what we are trying to accomplish for the benefit of the grid and for the benefit of customers, before we just reflexively raise our red flag of jurisdictional issues. So I wanted to get that point across. I'm not speaking for anybody but myself, I suppose, though people might assume I'm speaking for my organization.

I wanted to get that point across about focusing on what we are trying to accomplish, but, at the same time, even if that is your lens, there are these tensions that will arise just naturally from a state commission's primary mission. A state commission's primary mission, across the states, is, effectively, to ensure the delivery of reliable,

cost-effective, safe services. Let me go back to the NERC example. We often show up at FERC for the reliability tech conference and sort of rehash some of the same testimony. Last time I came, I didn't even broach the subject, because I'm like, they're done hearing this. I'm not going to go there anymore. But, really, the principle that was espoused for three or four years during this reliability tech conference was, OK, so if you're at 98% reliability, and then it's going to cost the consumers of the state of Ohio a ton more money to get that extra two percent, is NERC conducting the necessary analysis to say, what's the cost benefit of this? And so we've been espousing that issue for a while. I'm not stumping on that issue here. I bring that up to say that, regardless of whether you are in a position, like me, of not being interested in turf wars but being interested in what's right for customers, which is just based upon a state PUC's mission, still, that tension will naturally exist.

Where else did we find it? The Clean Power Plan. Unequivocally, the Clean Power Plan, in my time at the commission, now five years, was the most contentious state-federal issue that I've contended with. Again, a typical PUC's mission is to ensure the delivery of safe, reliable, cost-effective services. So, when we ran our potential cost studies associated with Ohio's compliance with the Clean Power Plan, it would have been pretty pricey. Now, that's not to say that breathing cleaner air is a bad policy objective. Of course, it's a wonderful policy objective. But from the state PUC perspective, when you have to ensure that you are supporting this core mission, statutorily, of what you are required to do, it runs afoul of, in that particular instance, the Clean Power Plan. So these tensions will naturally arise.

But I guess I wanted to begin by saying that I'm not looking to pick a fight. And I know that many of my colleagues are actually not looking to pick

a fight. These tensions just arise because they arise. At the same time (this is really un-PC, but if you know me personally, I'm kind of a jokester), I sometimes say to NARUC staff, "Hey, look, you can't get a bunch of commissioners in a room and start talking about state-federal, because it'll end up like a Klan rally." Now, I don't know what the hell a Klan rally's like, I've clearly never been to a Klan rally, OK, but once you start getting state commissioners really riled up about this issue, it becomes like this momentum thing that you can't tamp down. And you can't have them peel a layer back and say, "Well, what are they actually trying to accomplish, and can we accomplish that? Or is it better for someone else to try and accomplish that for the benefit of our customers?"

So, just a little lens into how I think of state-federal tensions, but let me begin with what was really the most contentious issue at the PUCO in December of 2013. The first purchased power agreement case was filed at the Commission by ADP Ohio. That was followed up by a purchased power agreement filing by First Energy. The goal was to essentially subsidize, through a particular mechanism, a certain number of megawatts of coal-fired and nuclear generation in the state of Ohio. Extraordinarily contentious cases. Eventually, the Commission decided that they would approve these cases. The mechanism was effectively that distribution utilities would purchase power from their generation affiliates at the cost to generate plus a return, whatever, if this power would then be liquidated in wholesale markets, whatever the delta credit or charge would end up being pushed down to customers. So that was effectively the mechanism. These cases eventually ended up at the FERC's desk, and the FERC effectively overturned these decisions, citing the affiliate transaction waiver doctrine using its Edgar Test. We won't get too deep into the weeds on that.

So the timeline for that was that these cases were decided in March of '16. Between March of '16 and when these cases were returned back to the PUCO, our then chair, Andre Porter, left the Commission to take a job elsewhere and I was sworn in as chair in May of '16, and this was one of my two, essentially, platform positions when I was sworn in as chair: "The PUCO is out of the generation business." I'm not interested in any more of these applications. I'm not going to entertain any more of these applications. We're done. Now, part of the reason I found myself in the position where it was supportable to say that we were done was really because of three decisions. First of all, the FERC waiver rescission piece, *Hughes vs. Talen*, which was a Supreme Court of the United States decision. And then, actually, a Supreme Court of Ohio decision that I don't know gets a lot of publicity, but it was effectively a case that overturned a Commission rider that would have provided "stability" to our distribution utility, specifically, in this case, AEP.

We have experienced a tremendous amount of what I'll call surcharge, rider, etc., fatigue in getting our marketplace from a vertically integrated, fully regulated marketplace to a deregulated marketplace. It's been sort of charge after charge after charge associated with getting ourselves from point A to point B. We're at the tail end of this. Actually, when you look at the landscape of where Ohio is, and the four formerly vertically integrated utilities, Duke Energy has sold its fleet to Dynegy, Dayton Power and Light is either selling or retiring their units. AEP Ohio has sold the bulk of their units and are retiring the rest, and First Energy Solutions appears to be headed towards a bankruptcy here in the near term, so we'll see what happens to their generating units during the bankruptcy. But this is effectively now the status of Ohio. We are at the very, very tail end of the entire deregulation timeline.

So, let me just touch briefly on what I think, for Ohio, is the next frontier of, not state-federal turf wars, but again, trying to figure out what the right thing to do for customers is. And so, I present to you our grid modernization proceeding which we have entitled Power Forward. This began in April of last year. It was a three-phase proceeding. Over 130 speakers came in nationally and within the state to talk to us about grid modernization. It just ended yesterday, actually.

So, we had about 100 hours of what we'll call testimony associated with grid modernization. Phase one was essentially building the business case for grid modernization: why do it? Phase two was a deep dive into the engineering of the distribution grid, and phase three was what you would think of in the context of, for instance, New York REV or Minnesota's E21 proceeding, discussing rate making, rate design, and some other facets of traditional grid mod proceedings.

All I'll say about this is that I think that at least my commission now, we're very well attuned to what the next level of investments will be from our distribution utilities, which hopefully correspond with net value being provided to customers. Now, how you monetize that, how you monetize, eventually, all of this, whether it's through net metering tariffs, or whether it's through wholesale markets, I won't go any deeper into it, is something that we'll have to continue to explore. And FERC's level of jurisdiction associated with the monetization of those resources in markets, versus what a state would do with their retail rates, is also something that I think will have to be explored, going forward. So, with that, I'll look forward to answering your questions.

Speaker 3.

Thanks very much for having me. I'm going to cover a quick overview of the history of state-federal jurisdiction over generation, and I do that

because the federal law is unchanged in that history since it was first enacted, and also because, since I'm a lawyer, precedent matters. Where we've come from tells us something about where we're going. Then I'm going to go do a quick overview of capacity market evolution and how the rules have shifted with regard to state policies. And finally, I'll end by talking about policy coherence, which is what the prompt for this session is about.

So, we all know that by the early 20th century, this was a state-sanctioned monopoly business. Utilities had total control of the system, subject to state oversight. Regulators and courts, over the years, have basically recognized that this has two principal purposes. One is to facilitate the industry's expansion. This was sort of industrial policy designed to finance the growth of the electric industry. And the second is, if you're going to sanction monopolies, you have to protect consumers. And this is reflected, as I said, in numerous court decisions, including federal court decisions that discuss FERC's authority, so the seminal just and reasonable case, *Hope*, the 1944 Supreme Court case, is about balancing consumer and investor interest, and that sort encapsulates those two twin aims of utility regulation: facilitate the industry's growth, and, at the same time, protect consumers.

The core public utility regulatory function is, one, to set consumer rates, two, to control exit and entry into the business (and this can be very specific in terms of providing specific authority to construct a new plant, which some states actually did, beginning in the early 20th century. In other cases, this was just a matter of shielding the utility from competition, allowing it to raise cheap money and finance expansion.) And the last function is to require nondiscriminatory service.

The first two functions here are relevant to generation. Generation was, historically, essentially paid for through consumer rates, and when states restructured at the end of the 20th century, they essentially removed those two public utility functions from generation. And FERC has essentially tried to re-create these two functions, setting rates and controlling exit and entry with competitive markets.

The system worked great. Obviously, we can't give regulators credit for all the improvements in generation over the years, but, notwithstanding a major financial crisis in 1929, the electric industry was relatively stable. It provided a good product, and it did so at a relatively affordable price, as the efficiency of power generation consistently improved. So this was a stable industry. The business model was working well. The regulatory model was working well.

And then everything started to look different in the 1970s. The price of constructing new power plants increased dramatically. This ultimately provided an impetus for restructuring. But the more immediate consequence of this was that consumer rates shot up, and this compelled a regulatory response from states.

So, what did states do? They did what states can do, which is add more mandates and add more processes. So, siting became a lot more complicated, as Speaker 1 alluded to. You now not only had to demonstrate that your new project was going to meet environmental standards. You also had to demonstrate all sorts of economic rationales for your projects as well. And then integrated resource planning kind of took that siting process and put it on steroids. Not only did you have to demonstrate that an individual plant was going to meet particular state standards, but rather that it was part of a comprehensive, long-term, 20-year vision that included both demand side programs and also supply side purchases,

including the utility's own interest in building its own generation.

And this was, legally, not really controversial. The federal regulator, FERC, could really make no claim to being able to regulate utility portfolios.

So, heading into restructuring, this was sort of the state of the law. In terms of developing power plants, the Supreme Court summarized, in a case in 1983 about California's ban on new nuclear plants, that the need for new power facilities, their economic feasibility, are areas that have been characteristically governed by states. And, by this time, wholesale power contracts were actually playing a role in power plant development. There were, for example, big nuclear projects that were shared among utilities through wholesale power contracts, but nonetheless, states really drove the development process, and particularly, it's that need part. The need for new power facilities, that was something that states were certainly in charge of, and FERC had no say over that.

In Order 888, the landmark order that ushered in restructuring, FERC affirmed that, of course, states have jurisdiction over integrated resource planning, utility buy-side decisions, and generation portfolios--it makes no claim on that, nor could it. These are clearly things that states have exclusive jurisdiction over.

So, heading into restructuring, that's really the state of play, at least as I see it. So then restructuring happens, and it's important to remember, here, that a lot of things change, and FERC does a lot of creative reinterpretations of the Federal Power Act, but all these things that I've put up here (market-based rates, open-access transmission, ISO/RTO guidelines, ISO/RTO formation, energy market rules, and capacity market rules) were just based on FERC's mandate to ensure that rates are just and

reasonable and not unduly discriminatory. There's no change in federal law. So there's no reason to think that those principles I just mentioned would have changed.

I'm going to spend just a few minutes diving into the history of capacity markets. As I mentioned, there were legal changes at the state level. The states, as I mentioned, removed generation from this public utility regulatory paradigm. States were no longer going to be setting rates and no longer going to be controlling exit and entry into the business.

This quotation is from a very early order into restructuring 2003: "The Commission's role with regard to resource adequacy is a supporting one and [] state and local governments must take the lead," and indeed, they were. In 1999 (just at the sort of very early stage here), six of the restructured states had passed RPS laws. So they did not see these wholesale markets as the exclusive mechanism for making generation decisions. In fact, states were still very interested in managing utility portfolios. So, states didn't realize, at the early stage of restructuring, that they were actually, in a sense, signing up for a system that was going to be relying on markets to address resource adequacy. I think it was reasonable for them to assume that they didn't see that coming, but by 2004, FERC had said, "Well, ideally, the energy market should be encouraging long-term investment." That was the ideal, but the ideal according to FERC wasn't exactly being achieved, and it sort of saw the need for some sort of centralized capacity market that was going to send locational price signals. That was 2004.

Two years later, PJM had worked out a settlement agreement, and the Commission approved a settlement agreement to create a locational based capacity market. And what I'm highlighting here is the Commission approving a limited version of the MOPR (Minimum Offer Price Rule). And

here, PPL and PSE&G wanted the MOPR to include state policies that were aimed at specific reliability projects. This would ultimately become the Maryland and New Jersey policies that would be preempted in *Hughes*. PPL, which then became Talen, let's give them credit for consistency and persistence, they had been opposed to this policy from the beginning, and they carried through the litigation all the way to the Supreme Court.

But here, in the 2006 FERC finding, the MOPR is limited to, really, market power concerns. And the same story here in New England, where, again, in 2007, FERC approves a settlement agreement and notes that look, states can continue to do what they want. We're regulating market prices, but if states want to favor certain environmentally-friendly generation, that's totally their prerogative.

This notion that FERC can regulate the amount of installed capacity through some sort of financial mechanism goes up to the DC Circuit. Connecticut argues that, "We have a 100-year history of regulating resource adequacy in Connecticut. We are perfectly capable of doing this. FERC is overstepping its jurisdictional line by trying to regulate resource adequacy." By the way, the Ohio Attorney General filed a brief in this case. The Ohio Attorney General noted that in 2008, Ohio passed an RPS and demand side management law, and the Attorney General was concerned that these new capacity markets are going to screw up Ohio's plans for resource adequacy and implementing its RPS. But in 2009 the DC Circuit sides with FERC, and it draws a line. It draws a line between direct regulation of generation facilities, which is something that only states can do, and regulation of wholesale rates, which is something that obviously FERC can do. And they say that the ICR (Installed Capacity Requirement) affects rates, and that therefore it's within FERC's jurisdiction. FERC is still

allowing states to develop whatever resources that they want. So, now capacity markets are on pretty solid legal ground with this decision.

And then, I think, capacity market rules take a turn. So, in 2011, FERC expands the MOPR. The term that I'll use is that it "weaponizes" the MOPR against state policies. I'm trying to spread is this term, "MOPR-ize," so, hopefully, you can all go and use that term. So, FERC MOPR-izes state policies here. Here they go back on their exemption for state reliability projects. This, again, has to do with the New Jersey and Maryland policies that will then be the subject of litigation. Now those policies are going to get MOPR-ized. Again, going back on where they were just a few years ago, FERC notes that "Effective mitigation of uneconomic entry into wholesale capacity markets does not encroach on a state's ability to act within its borders to ensure resource adequacy or to favor particular types of generation." So, again, FERC wants to reassure states that, look, we're regulating the market here. You guys still control generation. You can go and do what you please. This isn't a jurisdictional problem. This is simply everybody playing in their own sandbox.

This, of course, goes up to the courts, as these things always do. And the Third Circuit sides with FERC, and endorses that this is an appropriate use of the MOPR. What FERC here has done is permit states to develop whatever resources they want, and use those resources however they wish, while approving rules that prevent the state's choice from adversely affecting wholesale rates. So, again, everybody's in their right jurisdictional boxes. Everybody's on the right side of the line.

And, basically, there's the same story in New England. New England comes up with its own mitigation measures. This then goes up to the DC Circuit, which essentially sends the same

message. These "out-of-market resources...directly impact the price at which the [market] clears." This affects rates. The Court says that the Commission can mitigate these effects as it sees fit, and, again, the Court reassures states. States remain free to subsidize construction of resources. FERC's orders simply regulate these price constructs. So, everybody is on their appropriate side of the line.

And I'm going to stop the story here. There are obviously things that happen afterwards, including some examples of FERC explicitly accommodating some state policies, and then, of course, there are the most recent orders, so this is a developing story. But this is the state of the law as I see it, where we are. I think there was a particular turn that these mitigation measures took in 2011, with courts endorsing that move. And so, it's sort of turned into being a FERC policy choice, rather than a legal jurisdictional problem.

One more case that I have to mention, though, in terms of describing where we are, is, of course, *Hughes*, because that's looking at this from the flipside. These other cases that I just mentioned were looking at the question, what's the scope of FERC authority to deal with state policies? *Hughes* looks at this problem from the other angle, which is, how far can states go in their resource policies before they run into FERC's jurisdiction and have to be preempted? So, this 2016 *Hughes* decision...I think, had Justice Scalia been alive when this decision was argued, we would have had a very different opinion, but Ruth Bader Ginsburg wrote the opinion, and it's very short, somewhat cryptic, some would say, and it doesn't really matter what I think about the opinion. What matters is what federal courts have told us about the opinion. That's how Supreme Court opinions generally take their meaning, particularly in an area like this.

So far, three federal courts have analyzed *Hughes* and told us what it means. It's two district courts looking at ZECs, and the Second Circuit looking at a Connecticut renewable procurement program. And all three courts have taken a very narrow view of what *Hughes* means. They've focused on this language here that I put in the first bullet, that the "fatal defect" of the program was that it "condition[ed] payment of funds on capacity clearing the auction." So that's what the courts have focused on. Another way of looking at what this line is is that state mandated contracts "operate within the [PJM] auction." That's another line from the *Hughes* opinion.

So, at least so far, *Hughes* is rather narrow and just sort of prohibits programs that do exactly or something quite similar to what Maryland did, which is conditioning payments of funds on capacity clearing the auction. What I think *Hughes* is not about is, it's not about price suppression. So, if your legal theory is that states can't have policies that are going to affect rates, I think you can find a hint of that theory here and there in the federal court decisions, but I think the weight of the precedent goes against that. Just saying that the state policy affects rates is not going to preempt it. And I think *Hughes* stands for that proposition, as well as other cases.

So how do we achieve policy coherence? So, Speaker 1 provided five paths forward. Here are four. There's a lot of overlap. I'm going to briefly reject paths one (expand *Hughes*—litigate) and two (mitigate state policies) and then talk very quickly about path four (integrate policy goals in markets).

So, we're headed down path one now. We have litigation about ZECs, as I mentioned. I filed an *amicus* brief in this case with Jim Rossi on behalf of 20 energy law professors. (I have to quickly promote my own website here, State Power

Project, where you can find this brief and way too much information on all these cases.)

But, basically, one of the things that EPSA (Electric Power Supply Association) is arguing is that ZECs are preempted under *Hughes*, and our brief doesn't really deal with that. That's one argument. The other argument that our brief does deal with and that EPSA's brief leads with is that ZECs are preempted because they are payments by the state in connection with wholesale rates. And we argue that endorsing that view would vastly expand the scope of FERC's exclusive jurisdiction. It would likely, then, preempt RPS programs, as well as an array of other clean energy programs, and that would be contrary to how FERC has interpreted the Federal Power Act since restructuring began, and that would unduly expand FERC's exclusive authority.

So, you can head down this path. We're heading down this path. Maybe ZECs will ultimately fall. I do think, though, given the history they laid out at the beginning, that you're not going to preempt a lot of these state procurement programs. So, state policies are here. I think you may be able to preempt some of them, but, certainly, I think there's a lot of state authority left.

The second policy path that is a possibility is mitigation of state policies. And for the argument against mitigation, you could look at Norman Bay's final dissent, from about a year ago, where he said that MOPRs are unsound in principle, unworkable in practice, place FERC in direct and recurring conflict with states, represent significant interventions in the market, and all of that's just in the first paragraph. Then he really gets going after that. And I also...this seems like a Band-Aid that is not sustainable. Ultimately, if you're trying to send accurate price signals to the market, but at the same time leave out a whole bunch of the market in that process, I don't see how those price signals are accurate. This is a

Band-Aid solution, but I'm not sure that's a good long-term solution.

So, let me briefly just talk about the legal foundation for integrating policy goals and markets that Speaker 1 touched on. And what might that look like? I don't know what that might look like. The New England states recently said that they don't want a carbon price. New York does, perhaps, want a carbon price. There's been a proposal in New England, supported by National Grid and others, to have this REC-like product, whose value changes with the amount of carbon that the resource abates. So that's something that's out there. You could have a renewable capacity product. I don't know. I don't have the right answer here.

My point is that there's a legal basis with which FERC can approve this. I wrote an article about this last year in the *Energy Law Journal*. The really quick overview of it is that the two key points come from the *EPSA* case. The first point is that, with regard to demand response, the Supreme Court endorsed the principle that FERC had jurisdiction, in part, because what FERC was doing was trying to improve the wholesale market. So, with any of these new market designs, they have to be about FERC improving the wholesale market. It's not about FERC trying to become an environmental regulator. It's not about FERC liking renewable energy. It's about FERC just looking at the landscape, recognizing that the state policies exist, that they cause parties to incur real costs, and that there is an opportunity to integrate them into the market, and that, therefore, improves the market. So that has to be what it's about.

And then, secondly, my other point about the legal basis for FERC is just about what "just and reasonable" now means. In the context of a competitive market. It's about enhancing competition.

So, could you have a market design that unifies disparate state programs, that brings them under one umbrella, one or two umbrellas, however it might be, and is that a mechanism for enhancing competition in some sense? That's a case that could be made. There are certainly a lot of obstacles to achieving policy coherence. Just the way the Federal Power Act works, there's sort of a glide path for this to happen. If the RTOs can bring one of these initiatives to FERC--if New York can come together and bring a carbon price policy to FERC, that'll give FERC an easier opportunity to approve it, as opposed to FERC mandating that somebody do that.

So, we need somebody to take the lead here, and who's going to do that? A lot of state policies are now geared around very specific resources. It strikes me that those are going to be more complicated, more difficult to try to create a market design around. So, to the extent that states really just want very specific things, maybe this whole issue is a dead end, and we'll just have to have those policies existing alongside markets.

And then, my last question is, are capacity markets here forever? It seems like they are, but maybe not. So with that, I'll turn it over.

Question: Your "achieving policy coherence" path four seem to be what you're sort of endorsing here, but it seems to be premised on agreement among all the states in a multistate market, and maybe I'm missing something. Clearly, that's a desirable goal, but I'm not sure how you're wrestling with different states with different policy goals. So, that was one question. And I had another clarification, but let me ask you that one first.

Speaker 3: I don't think it's necessary. I think the legal actor here is the RTO, so that's the one that's going to bring the policy before FERC, and

the policy proposal obviously has to make sense in the context of a multistate market. The states are sort of, in a sense, quasi legal actors here. They don't have to agree with what the RTO does. In fact, they often don't. So, it's up to the RTO to bring the right policy before FERC, but it doesn't require unanimity among --

Questioner: Then the RTOs are imposing environmental policy on the states, whether they like it or not?

Speaker 3: Again, the goal here is to improve the market, so, rather, you're looking across the suite of state policies that exist and trying to come up with some unifying framework. It could be that PJM, because there's West Virginia and because there's New Jersey in the same market, maybe this is a pipedream in the current market system.

Questioner: All right, let me go for one other clarification. In your general criticism of some of the other paths that Speaker 1 laid out, you talked about how some of these other paths preempt the states. I'm trying to understand that, because, really, I'm viewing all of these as really trying to somehow react to various policies of the states, not preempting them, and actually, there may be a concern in the other direction that some of the arguments in Illinois and elsewhere had the effect of potentially preempting FERC. That's kind of what the *Hughes* case was about. So, I'm tripping on your word "preempt" the states, as opposed to trying to change market designs to accommodate the states. But explain, when you use the word "preempt," what you actually meant here.

Speaker 3: It's possible I misspoke. I'm not sure exactly what sentence I used that word in. Certainly the four paths...the first one was expanding *Hughes* and litigating, so that's certainly preempting. With the MOPR, I didn't mean to suggest that was preempting, so I might have misspoke.

Question: My recollection of the Connecticut case, where the court ruled on the authority of the RTOs to have a capacity requirement, was that that was about ensuring just and reasonable energy prices. Has any court ever ruled that when the states went to retail restructuring, they were able to grant FERC authority over reliability and capacity resource adequacy? Or has the conversation always just been around just and reasonable rates?

Speaker 3: I don't think there's a case that stands for the proposition that states sort of actively gave something up with restructuring. Like the Connecticut case, like the other ones that I mentioned, stand for the proposition that FERC can't directly regulate generation facilities, and when FERC regulates capacity markets, it's simply regulating something that affects rates, and it's acting within its sphere to ensure that rates are just and reasonable. So, I'm not aware of a case that stands for the proposition that you just outlined.

Question: You said that if Scalia had still been alive, *Hughes* would have turned out differently. How do you think it would have turned out?

Speaker: Well, there was a trio of Supreme Court energy cases. There was *Oneok* in 2015 and there was *EPSA* and *Hughes* in 2016. Scalia was in the dissent in *Oneok* and in *EPSA*, really reinforcing the notion there's a bright line between state and federal jurisdiction. I think the majority opinions in those two cases really pushed back on the bright line and had very clear language that, in fact, that they're interrelated and there's cooperative federalism and things like that.

It's sort of a mystery as to why the court took *Hughes*, because it lower courts had been unanimous in striking down the New Jersey and Maryland programs. So this is pure speculation,

but, given the rules here, I can speculate. It's just a guess that Scalia wanted to take *Hughes* as an opportunity to reinforce that there is still some sort of bright line here, and that *Hughes* was a vehicle for potentially doing that and tamping down some of the language in those other decisions, but that's just speculation. So I'm guessing that he would have written that opinion. He liked these energy cases, and so, just a guess.

I think if you read those other decisions, they, I think essentially overturn the notion that there's a bright line between state and federal jurisdiction; they implicitly overturn that idea, and I think Scalia would have pushed back on that to the effect that there really are separate spheres, and we can define what those are.

Speaker 4.

My basic theme is going to be that the law is a muddle, and the reason is the Supreme Court. I want to remind everyone that the reason we had a constitutional convention was that we were trying to figure out what the appropriate allocation of responsibility was between the state and federal government. That's what the convention was primarily about, and Hamilton, who was the smartest guy there, I think (Jefferson and Adams were in Europe), stood up and said that this will never work. And we're now dealing with the aftermath of that. You all can ask yourself whether it's worked.

So, here are my conclusions. I'll give them to you first and then go back to the analysis. I'm going to take you on a history lesson. The Supreme Court's jurisdictional analysis has become unmoored from the language of the Federal Power Act. You can't look at the language of the Federal Power Act anymore to find the answer to questions. Secondly, the reason this has occurred, in my mind, is that the Court has consistently sought to expand the federal role at the expense of state authority, relative to what was written in

the statute. I will agree that the Court was responding to industry changes, that the industry became more interstate and, therefore, a federal role was more important, but isn't this legislating? Is that the judicial role? And I think we're now getting very close to case-by-case analysis, because the guiding principles are so uncertain.

So, this all starts in 1927 with a sale of power from Rhode Island to Massachusetts. The fundamental problem in Attleboro was that the selling state wanted the rate to be higher, and the buying state wanted the rate to be lower, because the selling state wanted to bring more money back to its customers, and the buying state wanted its utility to pay less for the power that was being bought for Massachusetts. That's an untenable result, and the court, fairly practically, decided that this couldn't stand. This was a burden on interstate commerce. We couldn't have inconsistent regulation. The Commerce Clause prevented it. And so, they said that the feds have a "paramount interest in interstate business" carried on between the two states, and state regulation of this transaction was unconstitutional under the Commerce clause.

That is the "Attleboro Gap." It left most (many, but not all) wholesale sales unregulated, OK? You've heard about the Attleboro Gap. That's it. The court created it in '27. The Congress comes along in 1936, and it says that for the part of the business that consists of transmission or electric energy in interstate commerce, or wholesale sales of energy in interstate commerce, regulation by the feds is necessary in the public interest. But it says something else very important. It says, "[S]uch Federal regulation, however, to extend only to those matters which are not subject to regulation by the States." And there is substantial legislative history which shows that what Congress' intent was was to just close the Attleboro Gap. If the states could not regulate it

because of the Commerce clause, then the feds would get the regulation.

But the problem was that in the next section of the Act, 201b, Congress went forward and it said that the feds shall have jurisdiction over wholesale energy sales and transmission facilities in interstate commerce, but shall not have jurisdiction over generation and over local distribution facilities. And it did not repeat the language, “[S]uch Federal regulation, however, to extend...” It said it only once, in 201a. Keep that in mind.

Now, I want to make a point about this. If you’re writing a statute, and you give generation jurisdiction to the states and you give wholesale energy jurisdiction to the feds, you are creating an almost necessary conflict between the two, because wholesale energy comes from generation, and that’s the issue we’re all talking about now. So, by putting those two things on opposite sides, Congress created a real problem, unless you give effect to this language here: “[S]uch Federal regulation, however, to extend only to those matters which are not subject to regulation by the States.” We’re only closing the Attleboro Gap.

So, we move forward in time and the first big case that comes to the Supreme Court, jurisdictionally, under the Power Act was 1943, *Jersey Central Power and Light*. And the issue was that JCPL made a sale inside New Jersey to PSE&G. Jersey Central owned only generation and transmission assets inside New Jersey and only sold energy at wholesale and retail inside New Jersey. And the question was whether JCPL was a public utility under the Federal Power Act by virtue of its ownership of its transmission facilities, and the Court said, yes, they are, because PSE&G took their energy and resold it in New York, so their transmission facilities were effectively being used in interstate commerce. And in order to get

around the Attleboro section 201a language, the Court said that’s not relevant, because this case is about whether they’re a public utility for securities issuances approval purposes, and that has nothing to do with sales or transmission. So that limitation that was in the 201a that I read to you doesn’t apply here. Three justices dissented. They said JCPL is an intrastate company. PSEG’s interstate business cannot be attributed to JCPL, and since state regulation of these securities issuances was clearly permissible under Attleboro, the state could regulate section 201a gave the regulation belongs to the states. Those three justices should go down in history as the last three justices who read the Federal Power Act.

Then we move forward to *Connecticut Light & Power*, which raises very close to the same issue as JCPL, except this time it is a sale, so the Court can’t rely on this distinction between sales and securities issuances. And in *Connecticut Light & Power*, the Court said that the feds have jurisdiction, and about section 201a, they said that that’s just a “policy declaration...of great generality.” It doesn’t nullify a clear grant of jurisdiction. Now, there are two problems with that. First of all, when Congress speaks, we don’t just say that we can ignore some of what they said, because we don’t like it. But, beyond that, if Congress made a policy declaration that it was not in the public interest for the feds to regulate things that the state could regulate, isn’t that worthy of being regarded? Does the Court believe that Congress went ahead and regulated it anyway, even though they had just found that it wasn’t in the public interest to do so? But, anyway, this language that I’ve highlighted here, that Section 201(a) is a “policy declaration...of great generality. It cannot nullify a clear and specific grant of jurisdiction, even if the particular grant seems inconsistent with the broadly expressed purpose,” pretty much eviscerates the Section 201a language giving jurisdiction to the states. This is probably the

seminal change in the interpretation of the Act, And this case, for years and years, stood for the proposition that Congress, when it passed the FPA, intended to go well beyond closing the Attleboro Gap, even though the language of the statute and the legislative history said otherwise. It's good to be king, as Tom Petty said.

In 1953, there was a case involving a sale from a hydroelectric project from California to Nevada, and the owner of the project took the position that it was state jurisdictional, because there was a provision in Part One of the Power Act, the hydroelectric section, which said that the states had jurisdiction over these sales. And what do you know, the Supreme Court says, no, feds have it, because this is covered by Attleboro, and the intent of the statute was to close the Attleboro Gap. That's what Congress meant in 201a, and since this is covered by Attleboro, it doesn't matter what the hydro section is, we're going to interpret what Congress intended. So now Attleboro has returned.

We move forward to 1964 which is the famous-to-us-lawyers *Colton* case. And, interestingly, in that case, the Ninth Circuit Court of Appeals had ruled that the wholesale sale there was not FERC jurisdictional by going through a Commerce Clause analysis under Attleboro and looking at the impact of the transaction on interstate commerce. And it found no impact on interstate commerce, and therefore, under Attleboro and the Congress's intent in 201a, there was no jurisdiction. They had read the prior case that I just put up here and apparently thought Attleboro was still relevant. The Supreme Court reversed. And this is the famous line on bright lines. The court said, we don't do this impact analysis under Attleboro. We don't look at that language under 201a. Congress intended a "bright line...between state and federal jurisdiction." If it's wholesale energy in interstate commerce, the feds have it. If it's not, then the states have it. End of story.

Bright line, no impact test. Remember that, going forward. Speaker 3 talked about impacts a lot. We're going to get back to that. And the Court said, again, that section 201a was a mere "policy declaration" and therefore doesn't play any substantive role--we can ignore it.

Now we move forward to 2001, *New York v. FERC*. Same principles, but this is the first time that the Supreme Court gets to address these principles in the context of transmission. And New York has the temerity, in 2001, to come in and argue that 201a limits FERC jurisdiction, because the states were perfectly capable of regulating retail jurisdiction. New York had been doing it all along. There was no Attleboro problem, and therefore, under section 201a, New York retained jurisdiction. Anyway, the Court comes in and reinforces, again, that they don't look at section 201a. It's merely a "policy declaration" and "prefatory language." It can't override the clear grant of authority in 201b. So, because the 201a language wasn't repeated in 201b, Attleboro and that language is dead. And it's very interesting. This time the Court admits that the legislative history of the statute said very clearly that they intended merely to close the Attleboro Gap, but the court said that this industry is really different from the one that Congress was dealing with in the 1930s when they passed the Federal Power Act, so we're going to ignore the legislative history. We're legislating. They don't admit it, but they're legislating. It's good to be king.

Now we move on, more recently, to three cases. First, *Oneok*. Now, *Oneok* is a Natural Gas Act case, and not a Federal Power Act case, but I think most of you know that the two have been treated as brother-sister statutes for many years. And here, the Court says that the Natural Gas Act "was drawn with meticulous regard for the continued exercise of state power," and it cites the same legislative history that was in the Federal

Power Act. And this time they say that they don't have a bright line. The boundary between federal and state jurisdiction turns on "a case-by-case analysis of the impact of state regulation on the national interest." That's 180 degrees from what the Court has been saying under the Federal Power Act. And completely at odds with *Colton*.

Then they move forward in *Hughes v. Talen*. And I have no problem with this decision. My only problem is, why did they take the case? The Supreme Court usually takes a case when there's ambiguity in an important area of law, and they want to resolve the ambiguity. Here, they said this is very narrow and about facts. The state had gone so far that they were actually effectively setting the wholesale price for energy, and therefore, even though states have broad jurisdiction over generation, we think they went over the line here and we want to make very clear this is a very, very narrow holding which is limited to the facts. So they have helped us not at all on the issue that we're here to talk about.

And then my favorite, *FERC v. EPSA* (and I will admit I was on the brief for EEI on this case and lost, and maybe I'm just a pouter), but the reality is that this case takes jurisdictional analysis, to my mind, to an entirely different place. This decision doesn't even look at Section 201 of the Federal Power Act, the jurisdictional provisions of the statute. It bases its decision on Section 205 of the Federal Power Act, which sets forth the rate making standard for wholesale sales and transmission. And it says, taking language in that section, which says that FERC's review of wholesale sales should not just look at the price, but also the "practices affecting" the price of those sales. They said, that actually turns into a jurisdictional grant, because we are now pricing wholesale power in a market. How do you price power in a market if FERC can't regulate supply and demand? It's Economics 101 said the Court. So what they've done is they've turned a statutory

standard for reviewing transactions that are jurisdictional under another provision into a separate grant of expanded jurisdiction.

And now, according to the Court, FERC has jurisdiction over demand response provided by retail customers. It is neither a sale of wholesale energy or transmission. We are outside the Section 201 bounds for the first time, regulating a whole new set of transactions on the basis that the price for those transactions has a significant impact on wholesale prices set in the marketplace. That's closer to the original Commerce Clause analysis, I might say, than the bright line. The bright line doesn't show up in this case at all; there's no discussion of *Colton*.

So where does that leave us? I've been here before, arguing that net metering is FERC jurisdictional. These are wholesale sales of energy from behind the retail meter. Can somebody explain to me, if demand response from behind the retail meter is FERC jurisdictional because it has substantial impact on wholesale prices in the marketplace, how can generation behind the retail meter not have a substantial effect? The effect is exactly the same.

So, one interpretation of *FERC v. EPSA*, in addition to the arguments I made last time I was here talking about this, is that *FERC v. EPSA* holds that net metering is not state jurisdictional. These are wholesale sales. They substantially affect prices in the marketplace, kilowatt by kilowatt, to the same extent as demand response. It also raises a question, when does distributed generation storage not affect wholesale prices? They always do. And, therefore, I think a fair reading of *FERC v. EPSA* is that FERC has it, all of it, distributed generation, it doesn't matter if there's a wholesale sale. It substantially affects prices in the wholesale market. Is that what they intended? Probably not, but, frankly, they expanded their jurisdiction so far in *FERC v.*

EPSA, it's impossible to tell where the lines are anymore.

And, finally, we're here talking about state policies regarding renewables. Anyone who's dealt with the duck back problem in California knows that state generation policies in California have had a very direct and substantial effect on prices in the wholesale market. For that reason, are those practices affecting wholesale sales that are now FERC jurisdictional? ZECs--they have a very substantial effect, in that the renewable generation that they promote has a very substantial effect on wholesale prices in the retail market. I don't think the Supreme Court intended this, but I think that *FERC v. EPSA* opens up a lot of arguments that are problematic. And so, my conclusion is, if you come to me and ask me, on the next case, what the law is, the answer is, "I don't know." Thank you.

Question: It struck me as odd that, just listening to two historical treatments of the evolution of Supreme Court decisions on the subject, some cases weren't mentioned, like *Mississippi Power and Light*. Have they become irrelevant?

Speaker 4: No, they haven't. I had to cut the line somewhere. You'll notice I left *FPL v. FPC* out, where a purely intrastate transaction was found to be interstate because it was in interstate commerce. That was also an expansion of federal jurisdiction. So I'm not claiming that this was comprehensive, but I was trying to make a point. I think we are now far afield of what Congress originally intended, and the fact that they split generation and wholesale pricing without some grounding... that's a conflict that's going to be very hard for us to resolve going forward.

Question: Could you also make the argument that state energy efficiency policies, and maybe even state inclining block rate design, affect wholesale

prices the same way that *EPSA* decided with respect to --

Speaker 4: Aren't state efficiency policies a form of demand response?

Questioner: I think so.

Speaker 4: I don't know where the line is anymore. It's not that I'm telling you that I think it is federally jurisdictional. I don't know. That's the point I'm trying to make. I think *FERC v. EPSA* is really way out there. That's kind of my point.

Question: I just want to make sure I understood correctly that Speaker 3 and Speaker 4 are interpreting one word, "affect," completely opposite. If I heard correctly, Speaker 3 says it's been very narrowly limited and, Speaker 4, you're saying it's very... I just want to make sure I understood that both of you are arguing the complete opposite point over that language.

Speaker 4: Well, I'll let Speaker 3 speak for himself. I think in *Hughes v. Talen*, it was intentionally narrowly interpreted. I think *FERC v. EPSA* just opens it wide open. Taking jurisdiction over demand response because it affects wholesale prices just takes us into new places, and I don't know where it ends up.

Speaker 3: I was saying that, as far as preemption arguments go, if you want a court to overturn a state policy, if your argument is that the state policy affects wholesale prices and is therefore illegal, I think that's a tough theory to get a court to buy into.

Speaker 4: By the way, talking about preemption, let me go back to this language. Well, I don't know, but the statute says that if something's subject to state jurisdiction, they keep it. Why do we have preemption cases, if the statute says the

states rule? If they have lawful authority to regulate it, they get it. Why do we have preemption cases? The Supreme Court has really just written that provision out of the Act, and that's led to an entirely different analysis of jurisdiction.

Question: *FERC v. EPSA* also made the point that the price of coal or natural gas, that all of these things affect wholesale rates. So, therefore, the implication is that FERC has control of all of these things as well.

Speaker 4: I don't think the Court intended that. But I think it points to the problem, the issue that I'm trying to raise here.

General Discussion.

Question 1: A question on transmission line siting. There've been, obviously, a lot of difficulties in terms of Clean Line not being able to build the projects they've been trying to build. Speaker 1 also mentioned Northern Pass, which has similar types of issues. And this question's really for everyone on the panel. How much do you think that's a function of those projects being merchant transmission lines, or is it a problem with siting multistate lines in general? And the reason that I ask that is that the related question is, now you've got AEP, you've got Xcel, who are making big investments in building wind generation themselves. Not just purchasing wind generation, but billions of dollars of investment in wind. And they're going to need to build lines to transport that wind. Is that, in some ways, a breakthrough, a game-changer? Is it the case that now that you have large utilities building wind, are they going to be able to break through some of those problems at the state level, either because they have more access to the legislators, or they have more connections with the commissions, than maybe a merchant transmission line does? So, that's one question, as to whether you think

that is going to make a difference at all. Is that going to get rid of some of these barriers, limit them? Are there workarounds? And if you agree with that, then is that another problem, because now, because you have utilities doing both the larger generation and the transmission, are then we moving away from more competition on the transmission side, which FERC and RTOs have been wanting to do?

Respondent 1: I'll try to unpack that a little bit. I think your first question was, is siting of intrastate things more difficult with certain kinds of transmission? Obviously, pipelines have faced all kinds of siting challenges. Also, most recently, there's this case, right now as we speak, of people living in the trees in Pennsylvania to stop tree trimming. So it's not gotten easier. I think that DC lines seem to have a particular challenge because of the perception that they just are a highway that goes without any exit ramps for the people by whom they go, which is actually what DC is. That's why it's very efficient. And this has been a question raised with Northern Pass in New England. I had a relative come up to me at Thanksgiving and say, "Isn't that just for Massachusetts?" And I said, "Well, you know, it's all one big connected grid." It was like, "Oh, yeah? That's what all you people say." [LAUGHTER] And I think that was a particular problem with Clean Line, that the states that were producing the wind, like Kansas, were more supportive than the ones that were between the wind-producing state and the population center.

There have been things built. I mean, there are lines to Canada in New England now that were built through a consortium of utilities.

And there also are plenty of examples of smaller things. When I speak in Boston, I'm continually told about some Sudbury line that has nothing to do with FERC. People wear T-shirts and run after me to tell me about this terrible line that

Eversource is building, where I've never worked. I have absolutely no present or past connection with anything to do with this line, and it just seems like a replacement line from what I've heard, but it's become very controversial. So it doesn't even have to be big.

As to the AEP project in Oklahoma, because they actually serve customers in Oklahoma, I think they might have a little more acceptance in the state than if they were kind of coming from somewhere else. I don't think the notion of a company owning generation and transmission lines is new in some parts of the country. So, that's not breaking new ground.

As to solutions, I do think local and regional partners, which is something TAPS (the Transmission Access Policy Study Group) has been pushing, is one of the best ways you can try to penetrate the government.

Respondent 2: I have nothing to add because I think Respondent 1 has it exactly right. I represent the developer of Northern Pass, and it's all about New Hampshire thinking that they're not getting anything out of this. So, why are we going to build this in our state? When the line does so many good things...I mean, it's just so obvious, given the problems they have in New England now. So I think Respondent 1 hit the nail on the head.

Respondent 3: I really won't answer your question head on. I'll just give you the state perspective of where our heads are with transmission right now. We're really concerned about the spend. We've got some approvals coming through the Commission where your average residential customer will be paying five to six dollars more a month for transmission. That's a lot. It's a larger increase than we've seen in recent times for our consumers.

Why is that happening? A couple reasons. First of all, and I won't get into the details, we've got to tackle the supplemental transmission project issue, which has been cropping up, and I think a lot of people have become aware of sort of a regulatory gap that we've got to tackle. And, second, in my state, if we're out of the generation business where are utilities going to invest dollars?

And I think one thing we've got to be thinking about is that we have a lot of retirements. We've got a lot of coal unit retirements that are occurring or will occur in the state, and the impact of that on transmission spend, I think we are experiencing and will continue to experience. This has typically been a we-don't-pay-that-much-attention-to-it area for the agency. And I think I've had more transmission-related meetings at the agency over the past probably three months than I've had in four years. So, it'll be a hotter topic for state commissions to tackle.

Respondent 2: I want to respond to something Respondent 3 said, because it's really important to me and my developer clients. If you look at the increase in the cost of transmission separately and independently, you will always get the wrong answer. If the cost of transmission goes up, it goes up for a reason, because there were reliability problems that needed to be fixed, and there were economic problems. And unless you look at the benefits that transmission creates, both in cost savings from eliminating congestion and in meeting reliability requirements, if you focus just on the cost of transmission, you will always get the wrong answer. And I urge you, when you evaluate transmission, to put it in the context of looking at the energy benefits that it brings.

Respondent 3: That's a totally fair response. Transmission costs are effectively pass-through for us. We do math checks, and that's about it. Again, the supplemental transmission projects are

something I think we have to look at, but we have to explain to humans in my state why their bills are going to be going up five, six dollars. So, your point is well taken. I totally agree. And so, we need to be able to take that, conceptually, and be able to espouse it in a message that is intelligible to state residents as to why their transmission spend is increasing.

Respondent 2: This issue is coming up in New England now, because they've built so much transmission up there and nobody looks at the fact that there's reduced congestion by over \$700 million a year, and that they've solved a large number of reliability problems in the region, and that they wouldn't have been able to interconnect all of this modern new gas generation if we had built the transmission. And so, I react to this, maybe overreact, but it is really important that you look at the overall dollars, and not the dollars ...

Respondent 3: That's totally fair. This is why I'm glad I'm here. Because there's a difference between the call from the upset neighborhood association versus the explanation that we're relieving congestion. Well, that guy doesn't care. And so, we've got to get the messaging right, so that when the increased bills happen, we are explaining it in a way that everyone can understand.

Respondent 4: I'm just going to briefly get back to the point about the distinction between competitive and utility transmission providers. I think you've hit on something that certainly is a political matter that I see play out. So, the Clean Line project actually did have a drop-off point in Missouri, explicitly so the Commission could find in-state benefits, and it still got rejected. Then you compare that order to a Commission order approving an Ameren project, or some traditional utility project. It strikes me that there are differences in how they're treated, and of

course, as you know, in some states, in Illinois, they had a legal problem because Clean Line wasn't a public utility, so they couldn't get certain approvals. So, there is a distinction, but at the same time, just because you're a utility doesn't mean you automatically get what you want.

Look at what's happening right now in Oklahoma with the AEP project there. It's still sitting before the commission, but an Administrative Law Judge has recommended that they reject that project. So we'll see, but I do think that the political factor of having the local utility involved is a significant difference.

In terms of transmission competition, I would just highlight that there's litigation right now in Minnesota about that state's Right of First Refusal law and whether or not that violates the Dormant Commerce Clause. So that'll be a very interesting case to watch.

I think there are a couple of interesting transmission competition issues before FERC right now, about how to ensure that RTOs actually are providing that level playing field for the merchant developers, and that's all I'll say about that, because some of them are sitting before FERC.

Respondent 1: I forgot to answer the part of the question on competitive transmission, which is in a pretty fraught state right now. Since Order 1000, there have been, in my opinion, numerous demonstrations that competition saves customers money. However, it would be an understatement to say it's been slower developing in getting acceptance on the part of the larger industry than we had hoped.

Question 2: So, when Speaker 4 was talking about the *EPSA* decision, I sort of scrunched up my face when he said he thought it could be read to expand jurisdiction of FERC over net

metering. And I spent a little bit of time over the break thinking about it, and it strikes me that when it comes to net metering, PJM is not involved, right? An analogy might be the contract path versus the physical path. PJM made it a wholesale transaction, potentially, by being the intermediary, and the Court did nothing on state DR programs. It didn't say anything about FERC having jurisdiction over those. So, when you think about that, is that a way to distinguish the *EPISA* case from the conclusion that FERC now has jurisdiction over net metering?

Respondent 1: I think it's a good argument. I don't think it is what the Court defined jurisdiction based on. I happen to think that net metering is FERC-jurisdictional anyway. It's a wholesale sale, just quite clearly. But the point I'm trying to make here is that if jurisdiction is determined based on whether something has a substantial impact on prices in the wholesale market, i.e., it is a practice affecting wholesale rates, which is what the Court held, generation behind the retail meter has the exact same effect, kilowatt hour per kilowatt hour, as demand response. Your distinction is valid, but I don't think that was the basis for the court's holding.

Respondent 2: I think there's a number of ways you could distinguish net metering. So, one, EEI has recently told FERC that net metering is part of bundled retail service, and so therefore it would be under state authority for that reason. FERC's position is that as long as there's no net sale over the course of a billing period, there's no wholesale sale. That's its position right now, but I think that there often are net sales. So there's that.

Demand response was a practice directly affecting rates in part because it was a rule in a wholesale tariff. I think that distinguishes it from net metering. There's also the fact that with demand response, there are sort of two layers of

it. There's that initial sale of demand response service from the consumer to the aggregator, and then the aggregator itself sells to the RTO. So, if you want, you could think of net metering as sort of like that initial sale, which FERC doesn't regulate. It's only once it's aggregated up and sold to the RTO that FERC regulates. And then, if you still want to give FERC jurisdiction, despite all those arguments, I think FERC still has wiggle room to decide, as a policy matter, that it doesn't want to assert jurisdiction. And that legal argument comes from the *New York v. FERC* case, where the issue was, does FERC have jurisdiction over retail transmission? And the court said, "Well, maybe they do, maybe they don't, but this raises really complex jurisdictional issues and FERC said it doesn't want it so we're just going to respect FERC's judgment not to kind of raise these jurisdictional arguments and just leave that one to the states."

Question 3: Very, very interesting panel. Thank you very much. I wanted to raise one other point that is germane in thinking through this issue of state sponsoring, which is that, actually, the MOPR did not stop subsidized resources from participating in the market, because a resource that had a REC, or obviously benefited from a federal tax benefit or a state tax benefit, was not stopped by the MOPR. It was very clear. In fact, I was surprised that the only thing the MOPR stopped was a state-sponsored resource of a particular site, not a technology. And so, actually, in New England, had there been a decision just to raise the REC level, or to raise the Renewable Portfolio Standard by another 20, 30, 40%, and push up the price of RECs, as I understand it, that wouldn't have prevented resources that benefitted from those additional RECs from participating in the forward capacity market. They would still have been allowed to.

So, what really sort of torqued the system was the decision of the states to go back to auctions and

initiating specific power purchase agreements for individual projects. That was a whole other level of intervention. I just want to make that clear, because it's not a matter of using a new structure to accommodate subsidized resources that have already been allowed in. It was a decision by the states to go to a mechanism, really a reassertion of an old mechanism, to a much greater extent that caused the recent requirement on the part of New England to grapple with this. And I want to make sure that's out there, because we're still going to see a whole lot of subsidized resources coming in anyway, and still potentially having an adverse effect on price formation, which, frankly, the market more or less just accepted. But it was this new torque with additional PPAs that really changed the structure.

Respondent 1: I just want to clarify. I hope I get this right. The ISO New England tariff has a specific definition, such that if a state program is open to all technologies of that type which can compete, then it's not MOPR-ized. [LAUGHTER] (I don't say weaponized. Let's stay out of gun control, at least.) But it's not MOPR-ized, whereas, if it's selecting a specific resource under the ISO New England tariff, it does face a MOPR. I don't believe the other tariffs in the other regions have that same provision. So, that's just a no.

Respondent 2: I appreciate the clarification. What I was trying to bring out was that, initially, the MOPR explicitly was not going to apply to any state policies, and there was a change where there were going to be some state policies that would be MOPR-ized. So, I think there was still a change on that level, too, but I appreciate the clarification.

Question 4: Thank you. Great panel. The legal discussion's been fascinating. It's something I've been tracking for quite a while, and where it left us was with this vague gray area. The advantage

of a gray area, as frustrating as it may be for lawyers, is that it leaves tremendous discretion for policy choices. We wind up with conflict where the Venn diagram circles touch or overlap, and, as you mentioned, the statute sort of sets us up for that condition where the Venn diagram circles between state and federal touch or overlap. But we have a choice about how much we want them to touch or overlap, and I know this is incredibly obvious, but I just want to throw it out there anyway, because that's sort of the level at which I think. And that is, we don't have the same level of conflict in MISO or SPP or California, because we have chosen to keep the market's circle narrower, so that it doesn't butt up against or overlap the states as much. We've made a policy choice to assign the Eastern RTO centralized markets responsibilities that we haven't assigned them elsewhere. We have chosen to create what is really an unnecessary overlap by assigning them the responsibility solely through the centralized market competition, as opposed to the broader bilateral and centralized market competition, of ensuring sufficient resource adequacy. We're setting ourselves up for a massive overlap, potentially, through the DER proceeding that's underway. I would advocate strongly for choosing to find ways to minimize overlap, rather than looking at what is an existing overlap and finding ways to make it work, where we have constant litigation, because nobody is ever satisfied with how that overlap is managed. So, let me just throw that out there for consideration.

Respondent 1: I'll just start by saying I don't know who the "we" was in your sentence, but I would aver, rather strenuously, that it was the states that made the choice to go to a merchant generation model, and that led to the ultimate reliance on a centralized auction for forward reliability. Certainly, in New England, I was there, I can definitely say that the companies did not raise their hand and say, "Please dismember

us. We don't want this generation anymore." It was really a choice, for a whole bunch of reasons, that the states made, and most of the states, other than Illinois and 10% of Michigan in MISO, did not make that same choice, nor did some of the other places--SPP and others that you mentioned that have a different structure. But I don't think it was FERC looking with a map and saying, you know, "We'll take jurisdiction over resource adequacy here, but we won't take it there." And if the states want to change that choice, at least speaking for myself, I am absolutely OK with that, as long as it's either clean, like you have it or I have it, or, if we're going to have a transition, it be a structured, planned transition. What I don't want is accidental re-regulation just one resource at a time that leaves nobody holding the bag for making sure that we're building for the future.

So, anyway, sorry to get on my soapbox. As for DER, that was why we didn't take the next step in the storage rule, because we knew there was some very significant issues, and I'm hoping we have a robust discussion on April 10th with the whole panel of just state regulators and I think there's a lot to work out.

Respondent 2: Well, my problem with what you said is the suggestion that lawyers don't like it when the law is ambiguous. [LAUGHTER]

Questioner: In-house lawyers. [LAUGHTER]

Respondent 3: I want to draw a distinction between states in New England and the mid-Atlantic region deciding to restructure, versus the decision that came out 10 years later with capacity markets. So I think there is a gap there, and some states, like Connecticut, Maryland, and Ohio didn't necessarily want to make that leap to capacity markets. I don't know the whole backstory, because I wasn't in the room for those discussions, but I do think there's some distinction there. And maybe they should have

seen that coming. Maybe that was inevitable, but, as I say, in 1999, six restructured states had RPS laws, so they weren't ready to give up their influence over the generation sector, even as they were in the midst of restructuring.

Respondent 1: Well, I'm sure this is an oversimplification, but New England went through an energy-only locational pricing LICAP (locational installed capacity mechanism) that was a disaster, not because energy-only has to be a disaster, but the way it was designed, and all the political pressures, and that led to the settlement, which was not unanimous, of a capacity market. But, you're right, they weren't simultaneous. Because in the beginning when the region restructured, like all the regions, of all the problems that we sat around and talked about, like how we're going to organize transmission, what about this, not having enough generation was so far down on the list, because the whole rap on the old utilities is that they overbuilt, right, and we had too much. We had these huge surpluses, and all these nuclear beasts and all that people were paying for, and so it was like they weren't figuring out, what about when we run out of this stuff? That was kind of *mañana*. But *mañana* came.

Respondent 2: Now the ISO's doing forward reports saying, I don't know if we can keep the lights on 10 years from now.

Respondent 1: That's a different issue.

Respondent 2: I know it's a different issue. It is an adequacy issue, though.

Question 5: Thank you. I'm going to follow up on the previous question and ask if the DER should actually go a step farther. My question is whether the FERC should, or whether it could, initiate a proceeding regarding LDC (local distribution company) level demand response in

scarcity pricing. Let me explain. First, clearly FERC would like to see improved scarcity pricing as part of its Price Formation Initiative. Second, proper scarcity pricing requires that real-time prices during tight marketing positions reflect price responsive demand, in terms of their willingness to pay, i.e., if I'm a DR resource, and I'm willing to curtail my load when prices hit \$1500, the ISO spot prices at my location should be at least \$1500 or higher. I think everybody's good so far.

But here's the problem. Many, if not most, of the DR resources, to the tune of thousands of megawatts in PJM, as we're correctly starting to develop more demand response, are not visible to the ISO. They don't offer on the demand side to the ISO. Although there are ISO-level DR programs, there are also LDC-level programs. And these LDC-level programs are taking place at the LDC level, and the ISO never sees the \$1500 that the LDC is paying to the customer who's responding to the price. The ISO only sees the missing load, which is essentially priced at zero cost, and this results in prices being suppressed during scarcity conditions. So, I guess my question, again, is whether the FERC should initiate a proceeding to ensure that LDC-level DR is coordinated with the price setting mechanisms of the ISO, or is that a step too far in terms of ruffling the feathers the state-federal jurisdiction level?

Respondent 1: I would think that the Distributed Energy Resource Docket, though it's not specifically about that, will address some of the visibility issue, because there are really two things we hope to look at. One is the money issues. Who pays what to whom? How do you figure out what the state pays, versus what the wholesale market pays? How do you make sure you don't get paid twice at the same instant for the same service, etc.? And the second is visibility. If you have a lot of behind-the-meter

car batteries, or whatever, if there's a wholesale market saying to the aggregator, "Hey, give me that peak storage you said I could get," and, in the meantime, you have a distribution control center turning feeders on and off to work our streetlights, or whatever, all the things that distribution companies do, how do they coordinate? How do you get that visibility? Well, you're raising a different visibility question. We have something already, without starting a new docket, that'll kind of force us to think about some of it.

Respondent 1: I would agree with Respondent 1. I think from here those two issues would, my hope is, be the issues that are addressed by state regulators. And this is a good first step, and then we've got a dialog from here.

Respondent 3: Let me give you a legal answer. In *FERC v. EPSA*, there's language to the effect that the Court is accepting FERC's ruling that states could opt out of the program. Which is bizarre in and of itself. But I'm not sure how far FERC can go, legally, in requiring the states to do something like that in this context.

Respondent 4: I think there are objections with some of FERC's initiatives that touch on distribution system issues that are styled as legal jurisdictional objections, but are really just sort of operational concerns. It seems like what you're raising here is something that potentially could be solved operationally without any sort of real jurisdictional issues. So, hopefully, it is.

Questioner: Well, it's actually slightly different, in that many LDCs may actually desire that those resources come in at zero cost and suppress the price. And so it may be that the federal government needs to come in and say that in order for us to have proper price formation when there's demand response, the ISO needs to see that in the price setting mechanisms, or else

thousands of megawatts is just going to show up during those tight market conditions and we will never get the objectives that the FERC is trying to get from the Price Formation Initiative.

Respondent 3: You know, asking FERC to step in aggressively to ensure that prices go up is not really the easiest thing to ask them to do.

Question 6: I agree with that this is a great panel. I'm going to make, I hope, three quick high-level observations, and the panelists can respond or not. Because I think there are three things we haven't talked about but that are really important. The first point is that all suppliers, as a matter of law, constitutionally and by statute, are entitled to just and reasonable rates. That's obviously a given, but what we haven't talked about is that you've got the same competitors, but some of them may be able to access only the wholesale market, and others are accessing the wholesale market and other sources. And since we're on the eve of the first day of baseball season, it's a little bit like saying you're going to have the home team get six outs, and the away team gets three outs. I'll just leave it at that.

The second, but related, point is that price suppression does happen, and I'm not going to say where or how, for high-level purposes, but the Commission itself very recently, and in court cases, has said so. So, that's the second given.

And that then leads, I think, to the conundrum that, maybe we've danced around it, but we really haven't talked about, and that is, under Speaker 3's helpful suggestions, and the idea of the five different lanes, the assumption, and this is I think the key point, seems to be that every state "public policy goal" is of equal validity or legitimacy, as if it was all about climate change. And so, I think the conundrum, as we try to work through this federal-state conflict, are cases where maybe something was not a state public policy goal. It

was market participants seeking things. So, I'm just making that observation, because I think that hasn't been discussed and needs to be out there. Otherwise, we're going to miss what's really happening.

And the last point, I guess, is a barbed question, and that is, it sounds like we're either in Speaker 4's world, where we're going to muddle through, and the courts will answer what they'll answer, and the problem is that takes too much time and in the meantime, markets are being affected. Or the other answer that we in the corner here were talking about (which I think I've said before, and every time I say it, people cringe) is, should Congress step in? Is the situation so dire, is the situation so muddled, that we should even attempt to go to Congress, or would that simply make the matter infinitely worse? Because it's either Congress or the courts, ultimately. And maybe that's the only question, and the other three are just things to put into the mix.

Respondent 1: I, for one, always trust Congress to do the right thing. [LAUGHTER]

Respondent 2: I'll respond to a piece of this, having to do with PPA (power purchase agreement) cases. I realize that my state's positions on this can appear schizophrenic at times, but now we're in a position where we don't have subsidized units in the state. So, knowing how the sauce gets made with subsidized units, it concerns me that we may accommodate, for instance, a state senator who's concerned about a power plant's shutdown and the economic impact on residents and schools in that particular district, which has absolutely nothing to do with power markets, has nothing to do with reliability, has nothing to do with cost-effectiveness. It's just an economic development concern from one particular region of a state. And so, I have true concerns about the sort of "accommodate" piece, because knowing how the sauce gets made, and

being sort of in the bowels of how a state operates, I'm worried about how the sauce gets made, and, now that we are in a state without subsidized units, I'm worried about all of the potential cherry picking that could occur if that accommodation begins.

Respondent 1: Can I give you a non-facetious answer? I think that technology has made the distinctions that were drawn in the Federal Power Act in 1936 very difficult to deal with. So the jurisdictional lines have to be redrawn. What I don't know is how to redraw them in a way that would be politically acceptable. We're dealing with the same issue the founders were dealing with at the constitutional convention. You can simply bring all the power here into Washington, but you and I know that's not going to happen. So, given where technology is, and that so much that affects the wholesale market is now happening deep within the distribution system and at the retail level, this is just a conundrum that we're going to have to muddle through.

Respondent 3: I'll relate your second and your third points together. Again, I only speak for myself, but it's been my view that it's not a super good role for FERC to be deciding which state policies it thinks are worthwhile and which state policies it might not think are worthwhile from a societal or policy perspective. FERC tries to have fuel-neutral rules where it can. I realize that we could have a debate about that, but I think that at least FERC, as a bunch of technocrats that has some insulation of independence from other parts of the system, can have that as an objective, and it's certainly been my objective. I think if you have Congress now designing capacity markets or trying to whatever...every time I testify, there are people who are all like, "What are you doing to my coal plants?" literally on one side, and then it might be time for someone else to answer a question, it's on some bizarre form of storage I've never heard of, and then I go back...and I don't

think you could expect Congress to say, "Oh, we're just going to be fuel-neutral technocrats." Now, whether FERC is or not is up to debate, but it scares me a little bit to think of a congressionally-designed market.

Now, are there things Congress could take up, on PURPA, on transmission backstop siting, and all kinds of other things to improve? I'm sure there are. Your neighbor to your left was just asking for ideas, but the thought of saying to Congress, "Hey, we're having some state-federal issues, let's redesign," I have to say it scares me a little bit.

Respondent 4: So, market power is at the heart of everything that FERC has done since it came up with market-based rates in the late '80s. Again, FERC came up with all this stuff on its own, and mitigating against market power is the legal core, it's the practical core, of this whole system. So when you say "price suppression," I think it's totally appropriate for FERC to ensure that there's no market power that's leading to price suppression. And I get concerned when we talk about price suppression in other contexts. Really, what we mean is low prices. For a lot of people, low prices are good. And so, yes, states have public policies that are in some contexts, in some markets, leading to lower prices, and for a lot of people, that's not a problem to be solved. So, I don't have an answer that you're going to like on this, but I just share the concern that FERC should not be in the business of choosing what's a worthy public policy. Some of the policies that are aimed more at economic development will have other legal vulnerabilities, like Dormant Commerce Clause, potentially. If your idea is to stimulate in-state business, that might be a legal problem. But, apart from that, as to whether a state decides it likes offshore wind or another state decides it really likes coal, I don't know that FERC, or Congress for that matter, should necessarily pick that. I don't know.

Question 7: Thanks. Following up on the earlier question about some regions with just the spot market and other regions with the full capacity market, for those of us who think that capacity markets have kind of jumped the shark and it's one episode too many, Speaker 1, you said a few times on previous occasions that the states haven't said they want to take back their resource planning. So, I want to probe that a little. What if they did come and say, "We have certain regulated or competitive retail suppliers in our state. We want to certify to FERC and the RTO that they are covered." Maybe they're able to pay the scarcity price, which I think should exist and be there, but, at any rate, they have the credit requirements, whatever else we are certifying that they are up to do the job, and it's in a market environment now. It's not IRP--or maybe they want to do an IRP, but they could do either way. What would be wrong with that?

Respondent 1: Well, first of all, may I remind you that Fonzie did successfully jump the shark. [LAUGHTER] I don't think there would be anything wrong with a state deliberately making a choice to change, if they say, "We have had this structure. We want to move to another structure." Obviously, that's happened. That's how we got to the system we have now. I think that if they are in the middle of a region that's part of a different structure, that gets to be a little harder and all, but putting aside cross-state issues for a minute.

I think if a state deliberately took back responsibility for resource adequacy, you'd have to have a transition, because people have built into these markets with, in some cases a forward price guarantee. Just like you had a transition with the stranded costs when you went the other way. You couldn't just say OK, effective January 1, there's no more market for resource adequacy, but I think as long as the state deliberately took it back.... But I had somebody from an RTO, I

won't say which, say to me, "The states want to choose and build the sexy stuff, and they want FERC to price and be responsible for the unsexy stuff." Well, that's not taking it back. The reason I remember that over more than a couple years is because sometimes I feel that's true. But if a state actually took it back, then, yes, they could. There's no entitlement to have it set up a particular way.

Comment: Just to be clear, taking it back would mean you'd have to pay the price in the scarce periods, in the winter peak in New England, or whatever, which isn't what the states are thinking about, maybe.

Respondent 1: Well, say if the state went the other way. Something like, "We don't want to be in PJM anymore, we want to be in MISO. We're more like those states." I mean, you'd have to do all the transition and everything, but I don't think FERC could say, "Oh, no, no, no." It's the muddle that bothers me. The not taking it back, but taking some of it back.

Question 8: In building new transmission lines (this also applies to generation), incumbent utilities in about 48 states, or 47 states, have eminent domain. Non-utility generators and non-utility transmitters don't. And so, to what extent is there a question about discriminatory access to the marketplace when a whole set of important actors have eminent domain powers, and another important set lacks them?

Respondent 1: Your question is about utilities that have eminent domain authority versus those, if they're not utilities, statutorily, that don't have eminent domain authority. So that creates a competitive advantage for the utilities that have eminent domain authority.

Respondent 2: I think this is one of the problems with Order 1000. FERC tried to divide the world

into those new facilities that the incumbents would build and those that they wouldn't, and that became a very hard line to draw. And with state laws prohibiting some non-utility builds, it became even harder. And, to my mind, that's one of the reasons why it's been very hard for FERC to implement rules that actually work. The universe of transmission facilities that non-incumbents can actually build seems to me to be relatively small. And even where they can, you run into all kinds of problems trying to figure out who ought to build it. But it is a very difficult problem. That being said, I think that when you bring others into the process, you do bring forth creative alternatives that the utilities alone might not have, and so you do help efficiency, ultimately in building transmission. So, to my mind, the reason that Order 1000 is so hard to implement and has not been implemented is that the issues it creates are so complicated, not just by these legal questions, but by a number of other questions, that it's just been a very vexing problem to get around.

Respondent 1: Well, I won't disagree that it's vexing. I believed and still believe that competition in transmission construction can be very good for customers. No one was talking about taking away the transmission that the incumbents own now, but I do think there's an element we haven't talked about. These aren't words I usually use, but what's the utility business model? So, in some parts of the country, the utilities used to be vertically integrated, and the generation went merchant. Now we see a lot of those utilities looking to invest back in generation, which is another whole interesting thing, in some of these green procurements. And then they had the transmission and the distribution, and in Order 1000, FERC said, we're just not so sure it's the best thing for the customers, the ones who pay the bills, for that one company to be able to decide everything that gets built and build it itself. FERC didn't have billions

of dollars of stranded costs to give back like Betsy Moler did to make a grand bargain with the utilities. FERC just basically said it, and some have been fighting it tooth and nail ever since, is my impression. Now, at least, they say, we still have our distribution business. OK, that's sacred. I mean no one could take that away, right? Like there's no rooftop solar and things behind the meter and, wait, you mean now that might be changed by technology, too? And so this, I think, is a big issue right now. The people we regulate are going through a lot of stuff. But I still believe that the arc is slow, but somehow getting more people into transmission is good for customers.

Respondent 1: Let me give you a technical answer to this. I haven't heard about this issue, and I think probably why I haven't heard about this issue is because, while our utilities have eminent domain authority, they don't have quick take authority, meaning you'd have to file an appropriation suit, but you don't have immediate access to the property. And so you'd have to wait a year or two years, anyway, to get your case resolved. My understanding of what happens with these, just across the board, is that the last three or four landowners that hold out, they essentially get paid quadruple. (I don't know, I'm making that number up.) They get paid way more than what an appraiser has said fair market value should be for the property. And so, I give you that context to say that, boy, I don't know that it matters that you have eminent domain authority, because the utilities, I think, infrequently...and maybe the utility colleagues in the room can correct me if I'm wrong. I don't know that utilities frequently file eminent domain suits and expect them to be litigated out for a year or two.

Respondent 2: That's the worst case. They don't want that to happen.

Question 9: This is going to sound a bit blue sky, but I think in 10 years it won't. It all has to do

with FERC jurisdiction in allowing retail customers direct access to wholesale market prices. Now, I understand why the FERC wants to do this, and basically what this is doing is circumventing inefficient retail rates. If the retail rates were set correctly, FERC wouldn't have to do this. It started with taking jurisdiction over demand response back in 2001, and it's extended through allowing storage resources connected to the distribution system to directly access wholesale prices. And it's probably going to go beyond that to gen DERs, generators at the retail level also being able to access the wholesale prices.

I think this is really heading toward a showdown between the state and the federal jurisdiction, and possibly even a requirement to rewrite the Federal Power Act. And here's why I say that. I think where we're going is to develop competitive market-based rates at the retail level, which will vary with time, and which will also be dependent upon the point of connection on the distribution system. Those prices are going to have three components. They're going to have the wholesale LMP, plus the losses, plus the congestion component that may occur if you have enough upstream asset that's approaching capacity on the distribution system. This is complicated, and if we allow direct access, we're never going to be able to get that type of competitive market pricing in place. Now, the thing is that we can solve it in two ways. We can let the ISOs solve the whole problem, going all the way down to each distribution system and each retail customer. I don't think that's feasible, certainly not with today's computational capability. The other is to separate this, and let the distribution system operate or solve the problem, set these prices based on the LMP at the offtake point, and disallow retail customers on that system to have direct access to wholesale prices. So, my question is, which way are we going to go? What do you think of all this?

Respondent 1: I think real-time pricing for consumers is like fusion power. It's always 10 years away. I don't know that FERC can do anything more. I mean, you talked about these other resources coming into the market. We've mentioned storage and DERs and whatever, and I think that is going to come in some form, maybe not direct, but through aggregators. But I don't see FERC having the authority to reach down and mandate real-time prices. I think this is still something that states are going to have to decide whether or not they want to do.

Respondent 2: I don't disagree with that. The concept of retail rates being set correctly...boy, I think when we look at our net metering tariff, versus the potential of receiving a wholesale price, I think there are potentially philosophical differences. I mean, right now our net metering rules read that if you're on the net metering tariff, you should not receive a capacity payment. And so, how that works in the grand scheme of balancing staying on a retail rate net metering tariff versus participating in the wholesale market, I can probably guess where that's going, if an aggregator were to come knock on the door and say, "I can get you more."

Now, look, I think the other thing to just think about and keep in mind is that I suspect that this will be an issue. I do not suspect this is going to be a near-term issue. I mean, in my state, we have very, very little DER penetration, very little. And so, our grid mod proceeding was a very holistic look at all things grid mod, including updating the grid for at least three of our utilities that have had very little in the way of infrastructure upgrades--just patchwork over some period of time. We have a lot of difficulty even getting customers to understand that we are a choice state and that they can shop. What we're talking about, I think, is something that we've all got to keep our eyes on but I also think that we're probably 10 years, or

probably 30 years away, possibly, from having this kind of concern.

Respondent 3: A couple of things. First of all, I think electricity is generally sufficiently inexpensive that retail customers won't care. They don't want to worry about paying a market price on what they get. Maybe large industrial customers and commercial feel differently. So, I think that's an impediment. Electricity's just really well-priced right now. Secondly, I think it's really hard to do, with the jurisdictional split that we have now. If the prices come from wholesale markets, it's regulated by one regulator, and retail prices are regulated by another. I think that's an impediment to getting it done, even if it made sense. So, I don't see it happening any time soon, and I think one of the lessons from REV is that it's easier to talk about than it is to do.

Respondent 4: To Respondent 3's point, I think the power of some of the technologies that are coming around, with Nest and some of the things that are happening, is that even a customer that's not that price sensitive--like me, I'm time driven, not price driven. So you could give me all the time of use rates in the world, and I wouldn't change the one window I have to dry my clothes. But if I had some kind of system in the home that does that...that's supposed to take that away from having the customer having to choose, and there are more and more studies that it's really changing the penetration of things with technology.

I also don't think that time of use rates should be as hard as fusion, because it's a political issue, not a technical issue, but, of course, I guess political issues can be as hard as technical issues. I think that even if we had universal time of use rates, there still might be places where resources collectively have more value to the big grid than they do to the distribution system. If you look at

all the middle of the day solar that's affecting the peak in California, even though that's very little individually, collectively, it is affecting how power plants dispatch. But to answer your specific question, I do not think FERC should mandate time of use rates. We have enough trouble with wholesale rates. We're going to have to leave that to the 50 state capitals.

Question 10: In some of the discussions that we were having, subsidies do have a suppressive price on wholesale markets. Maybe that's not always the point of the subsidies, but they do still have a suppressive effect on wholesale prices. And for those of us who rely on the wholesale markets for our revenue, we can't tolerate that. So we can't just say, "Yeah, the states can do what they want to do." Maybe the states can do and should do what they want to do, but we have to acknowledge that. We want the states to be able to do what they're going to do, but then we have to say, "OK, we're going to allow that to happen, so we have to have a different construct to pay generators for participating in the market."

Respondent 1: I think where that's taking you is that you're hoping that FERC will step in and undo those subsidies to make the markets fairer?

Questioner: To protect the market, not undo the subsidies, to protect the market.

Respondent 1: That's a hard thing to ask a regulatory agency to do. I think that's just going to be a really difficult thing. Not that you aren't right, but I just think asking FERC to unsuppress prices is a politically very hard thing to do.

Respondent 2: Is there any distinction between a targeted subsidy for a particular resource, or a state tax subsidy, or the vertically integrated model in general?

Questioner: The vertically integrated model?

Respondent 2: Well, if state vertically integrated utilities get to recover their costs through retail rates, regardless of wholesale prices, is that equally suppressive?

Questioner: Do you mean like Dominion participating in the PJM market, for example? Yeah, if all of the utilities in PJM were Dominion, PJM wouldn't work. It's not very many, and we do tolerate. We tolerate some amount. You know, RPS is a subsidy also, and we tolerate it, because it's been small, and generally the markets have been working. I think competitive markets have been very successful, and I hate to see them go away, but we can't just leave the competitive generators out there without enough revenue or without sufficient revenue. We don't like low prices, but we're not against low prices, if it's fair. If it's because we've got a lot of natural gas, and that's what's setting the price now, that's OK. We'll muddle through that. We'll have to just weather that storm, because that's the market working. But it's the subsidies that are the problem, that are now making the wholesale market that was created and has generally been working, it's now chipping away at that, so that the competitive market at some point is not going to be sufficient. And really is not sufficient in California, for example.

Respondent 2: It seems like the challenge, then, is to find what that tipping point is, and who defines what that tipping point is, and what subsidies are tolerable and what subsidies are intolerable.

Questioner: Well, we would certainly say that California has reached the tipping point, for an example. And you see it. Without talking about anything specifically, you do see the changes that are coming because of that.

Question 11: I have a question about the distribution initiative in Ohio. One of the reasons

we restructured was to shift risk and reward. And I guess the question is, how do you all ensure that in these distribution reforms we're not using rate payer money to bet on the wrong technology? How do we keep the risk-reward allocation that we've tried to do with restructuring in Ohio, how do we bring that in to some of the distribution reforms that are on the table?

Respondent 1: Look, I think the Power Forward proceeding was really helpful on a number of levels. First of all, through all of these speakers that have come in and educated us, we've built a tremendous knowledge bank associated with the distribution system. Now, we all know how distribution rates are created. We have, in Ohio, rider opportunities, in between distribution rate cases, to collect on basic capital expenditures, as well as, now, smart grid riders.

So, let's look at this all totally holistically. So, there is the spend issue, meaning, where will these expenditures be recovered? And then there is the question of, what should you allow for recovery for, because one concept that we kept on hearing during the Power Forward proceeding is that the lines between G&D (generation and distribution) are being blurred every day. And so, one definite takeaway is that we will produce a product eventually, certainly before the year is out, associated with Power Forward, and state commissions are going to have to increase their competency on the engineering of the distribution system, more so than they have historically. This is a changing and dynamic distribution system and if a commission is not able to technically evaluate these applications that are going to now come in that may be blurring the lines between G&D, may be blurring the lines between what's appropriate in front of the meter and what's appropriate behind the meter...if commissions are not able, from a technology perspective, to parse through all of that and say, A, what is appropriate to recover and then, B, where should

you get to recover it, I think we're doing a real disservice.

Also, seriously considering the concept of just statewide interoperability for the benefit of third party technology providers who are very interested in starting to offer innovative products and services on the distribution system to our competitive retail community. And so, I think, on the D side, there is this really wonderfully unique snapshot in time where we are right now where three of our four utilities really want to make substantial upgrades to the D system. And if you think about that, if we're able to wrangle all of these folks together and say, how do we create call it a "distribution system platform" that is going to be fully statewide and somewhat interoperable...

We obviously take incremental steps, and are looking at trying to future proof every investment, which is really the hard part. I mean, that's really the crux of your question, the future proof question. And, outside of scientifically ensuring that we understand what's being deployed, there's really no answer other than take baby steps, understand what is being invested in, and ensure that there's interoperability amongst your stakeholders.

Moderator: Thank you. So, we started out our discussion asking the question whether or not there is some coherence, from a policy perspective, when we're looking at state and federal jurisdiction. I'm not sure that there's a whole lot of optimism here. We've heard some things, like the idea that jurisdictional line must be redrawn. There's some fear or concern about what might happen if Congress ever had to step in. And then some have expressed some serious tensions between state and the feds on these jurisdictional matters. So, I don't know where we are, but I'd like to thank the panel.