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Rapporteur's Summary*

Session One.
REV and Beyond: Looking Ahead to Technology Disruption

Information constraints on efficient market animation are receding rapidly with advances at the technology frontier. From better, faster measurement, to optimization and control, the range of activities in electricity systems is expanding. The challenges for policy are either here or just over the horizon. In regulated states, system planning needs to evolve to include increasingly complex options. In competitive states, efficient market signals need to provide incentives compatible with the wider range of technology solutions. Research on technology innovation is active through both private initiatives and public programs such as at ARPA-E in DOE. What are the new technologies entering the market or that would be commercially available in the near future? How do these technologies provide benefits, and how would the system exploit these benefits and avoid unintended consequences? How much of the potential disruption is going to require new policies and regulatory oversight? How much do existing policies provide a barrier to innovation?

Moderator.

We're going to be talking about the stage of development of a number of emerging technologies, some of them ready for deployment and commercialization, some of them less so, as well as the policy setting for how those technologies might be encouraged for adoption to substitute for less efficient technologies that are currently widespread. This is not meant to be a comprehensive panel on emerging technologies, but to give you sort of a hearty sample thereof and hopefully encourage you to ask some questions afterwards.

Speaker 1.

I'm really excited to be here. Thanks so much for the invitation.

For an audience like this I don't really need to spend a lot of time on motivation, but I'll just highlight the fact that there are a number of emerging trends that we're all working with,

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from distributed renewable generation to changing consumer demand to managing cybersecurity threats and increasing the resiliency of our infrastructure. Ultimately the technologies that address those challenges, I believe, come in three different categories: those technologies that enable improved understanding of the system's state, those technologies that allow us to control the system in a more granular and exact way, and those technologies that allow us to take those controls and take that awareness and understanding of system state and optimize the system better.

Let me give you a couple of examples. At the core, the foundations that enable understanding are all of the advanced sensors that we're already deploying, the ubiquitous high-band with low-latency communications that are being rolled out everywhere, the advanced analytics techniques that in many cases we're borrowing from adjacent industries. The controls include, of course, distributed energy resources, but they will come to also include the rapid advances that have been made in medium-voltage as well as high-voltage solid-state power electronics.

At ARPA-E I had several projects working on individual transistors that operated 20,000 volts. When you can get a single transistor that goes all the way up into medium voltage, the world changes in terms of what you can do with power electronics. Finally, on the optimization front there's been a tremendous amount of work in the research community on advanced optimization algorithms, and there's a lot of thought now on what advanced architectures and new control schemes might look like.

So, in the understanding space, technology has ultimately enabled higher bandwidth, low-latency ubiquitous communications, and cloud-enabled data aggregation and analytics. We're seeing a lot of organizations now say, "Hey, it's much easier and cheaper and faster to collect all of my data on the cloud, where I essentially have limitless computation that I can apply to that data." This is happening today. We have higher precision and higher frequency sensors that are now commercially available and widely deployed in transmission. That same technology is now starting to make inroads into the distribution system. And our ability to forecast, all the way down to individual customers in many cases, is now becoming commonplace, and there are vendors and startups out there who are working on all four of those areas.

One example that I will point you towards if you want to learn more about this area is a project that ARPA-E ran on thinking through what it would mean to put synchrophasor measurement units in distribution systems. What are the applications that that would enable, in terms of increased understanding and system state awareness?

In the area of controls, new controls that are becoming available to us will include power flow controllers. There are many types of power flow controllers that are currently in development based on advances in the power electronics domain.

There is energy storage, of course, whose costs are falling rapidly. Internet of things devices, grid-enabled appliances, are all becoming far more cost-effective and widely deployed. And, of course, there are advances in microgrids and the concepts around how you would control islands as well.

A couple of examples that I'll point you towards from ARPA-E projects in this area relate to a lot of work that ARPA-E did in power electronics-based power flow controllers. These are far lower cost, relative to the devices that originally were piloted back in the 1990's under the FACTS name. These things are now in late stage pilots, and in many cases they've now gone into the field in actual deployments. Some of them are focused on distribution, and some of them are focused more on transmission systems. These aren't yet fully commercial and widely deployed, but they're right on the cusp of that. And these now allow you to start to take control over how power distributes itself throughout a mesh system. Your mesh system is not simply a "take it and optimize around it" system anymore. In addition to the controls at the edge and the controls at the central generation, you can now think about actually controlling the nature of the network itself in real time. These either inject impedance, or they inject additional voltage into whatever line they're located on. Finally, there's been a lot of work in optimization algorithms, and this work's really just now starting to bear a lot of fruit as the research community starts to prove all of these algorithms on much larger systems and much larger test cases. I firmly believe we're going to see a lot of advances in the optimal power flow algorithm space, allowing us for the first time to truly coordinate and co-optimize both real and reactive power flows throughout systems in both the transmission system as well as increasingly in distribution systems, where there's going to be a lot more generation, a lot more controllable customer demand.

We're going to see a lot of work in, and I believe we will see a lot of progress in, algorithms that help us coordinate and eventually co-optimize interdependent infrastructures such as electric and natural gas. ARPA-E funded a project on this topic that I'm very excited about following over the next couple years.

There's a lot of work happening in distributed optimization. It used to be that you had to do everything in a centralized fashion--pull all the data into a single place, run an algorithm, find the best solution, communicate the results out… A lot of other industries are now starting to widely use distributed optimization. There's a lot of information exchanged between all the different places where you're running optimization algorithms, but it gives you a tremendous amount of additional flexibility to find what you're trying to solve, what the objective is, what are the goals at each level and each entity involved in the system. This is a toolkit of optimization algorithms that we just simply did not have in the past, and it could have very large implications for this industry, especially as we think about integrating transmission and distribution system operations far more closely.

And I'll talk about new grid architectures for control as well. One ARPA-E project I'll point you towards which I'm very excited about is a project that ARPA-E did on transmission topology optimization and line switching, led by Pablo Ruiz at B.U. And he's now launched a company called NewGrid that's trying to commercialize this technology. What they did is they took the fundamental concept of line switching that had been explored in the economics literature to some degree, and they actually applied it to large-scale real systems and tried to estimate just how large the congestion benefit could be from a software fix of implementing algorithms to let operators know when it was feasible and optimal and beneficial to switch lines out of service. Again, this isn't something that is fully developed and fully commercially deployed and widely used yet, but it's on the cusp.

And so, it's up to this community, I think, to really start to think through the potential policy and economic implications. If these algorithms prove to be real, how do we deal with that, and how do we best integrate them?

Let me talk a little bit about control, because this is an area that I'm very excited about. It's an area that I'm actually working in now. All of those technologies described on the previous slides - understanding, controls, optimization – when taken together, eventually allow us to think entirely differently about how we organize and we control the overall system.

So, let me suggest for a moment that we think about a particular approach to control that I'll call "agile and fractal control." The grid consists of control areas. These may be individual utilities or entities. These may be different regions. They may be different individual distribution feeders. And in a world where you have a lot of distributed generation, and you have a lot of storage, so you've got a lot of flexibility built into customers, you actually can start to think about defining the boundaries of those control areas depending on system conditions. What's the weather like? What do I expect the next several hours will be? What's the resource availability of generation? Which of my communications networks are working right now? Where do I fear I might have a cyberattack in play? Each of those control areas can interact with the other control areas in the system using a variety of different means, and we don't know yet which of those is going to be best, and it may very well be system dependent.

And what I mean by fractal is, we think where you need to go is you need to embed the same control logic and same control capabilities at every level of the system. Each individual small microgrid needs to be able to manage its grid and do everything required to provide power to customers. It may, depending on system conditions, integrate fully into the distribution feeder that it's located on, and that distribution feeder should be able to fully operate itself and manage all aspects of delivering power to customers. Depending on system conditions, that feeder may integrate with the neighboring feeders around it, coming off of one or more substations. Eventually those substations may integrate with the broader regional transmission system. In normal conditions the system would end up looking exactly like it's always looked. The economies of scale still exist. The efficiencies of scale still exist. But, depending on conditions, there may be other scenarios where that's not necessarily true.

So, let's say you have a system fed by two substations, and you have customers located in that system that have their own generation and/or storage. In one example, you've got a certain portion of the system fed by substation A, you've got a certain portion of the system fed by substation B. It looks fairly normal. And maybe in an emergency condition you may switch part of that system, and you may move load from substation A to substation B. We're starting to routinely do that today. But maybe, under certain conditions, it's actually optimal for a piece of the system to supply its own generation, either due to economics, due to expectations related to how the system's going to evolve over the next several hours, perhaps even due to emissions concerns. Or maybe it makes sense, under normal conditions, for a piece of the system to island itself off in order to deliver power to a certain set of customers. Now, there are very good engineering reasons why we have not done this in the past. It's really hard to enable this. There's a lot of detailed engineering that goes into enabling this to happen without sacrificing safety, but all of the technologies necessary to enable this sort of dynamic system operation, where you're continuously managing control areas, are now becoming readily available. It's those same technologies that enable better understanding, better controls, and better optimization.

What's most important to think about here, though, is that this is not just about engineering the physics of how the grid operates. This is not just an engineering question. You also have to manage all of the transactions between all of the customers. You have to ultimately think about, well, who has the responsibility of providing service? Who has the responsibility of ensuring reliability and resiliency? What is the policy and economic framework that we have to wrap around the engineering capability and possibility here to actually make this a reality?

At the end of the day, if you enable these sort of dynamic system operations, you enable even more of the potential benefits from distributed generation in the form of perhaps lower costs, but certainly higher reliability, as well as much greater system resiliency.

This is clearly not a concept that ready to go today. It's not something that's on the shelf, and that we can pull off and implement immediately.

But all the elements are here or in development, and this could be a very real possibility soon.

Let me end with just a couple questions that I hope this presentation has raised, and that I hope that we will address in the discussion. First, how can we reduce barriers to appropriate R&D evaluation, testing, and adoption for new technologies? We very much see a valley of death between early R&D, utility pilots, and testing in this industry today. Many of the technologies I've discussed don't look like traditional utility investments. There are new methods of delivering technology. The big one, of course, is software as a service. How do we manage that appropriately, and how do we regulate that?

And with every one of these technologies there are very large questions about who actually captures the value. And there are very interesting conversations that could last us all day on the cost, the revenues, the risks, the benefits, and ultimately the beneficiaries of all these technologies.

Finally, there are questions related to the control schemes and the control architectures. Fully realizing the benefits of those will require new interactions, new information sharing, and new roles and responsibilities among all stakeholders. I'd like to raise the question of when is it appropriate to address these questions, and who should be really doing the work of working through all those tough questions? Ultimately, one size will not fit all, so different arrangements will certainly be optimal, based on local conditions, geography, historical context, system density, etc. But at least we need to study the menu of options so we can understand the strengths and weaknesses of different approaches. And with that I will stop. I look forward to the discussion. Thank you.

Question: I had one quick question about this last element that you were discussing, this fractal control view. Does that have to be sort of autonomous, meaning there would be no human involvement, because of the nature of everything having to have full capabilities? Or is that not necessary?

Speaker 1: That's a good question. Let me give that a little thought and I'll come back to it. The first implementations would probably not be fully autonomous, but to truly adhere to the fundamental core concept, eventually you would probably have to have everything be autonomous, yes.

Question: Are you saying that for the model that you describe, it has to be 100% adopted, from the bottom up, or can you incrementalize adoption?

Speaker 1: No, I would expect we would find incremental adoption. It may start locally, it may start regionally. It certainly wouldn't have to be 100% from day one.

Question: On the distributed optimization, I'm assuming that in order to carry that out you've got some sort of iterative algorithm between the different components so that you can do this more quickly. Is that correct?

Speaker 1: That's exactly right.

Question: Can you say more about dynamic system configuration?

Speaker 1: Ultimately, you're limited by the physics of the system, and it's not a fully switchable system. So just as in the example of transmission line switching, system configuration may allow you to deliver power from a certain source to a certain customer in ways that you wouldn't otherwise be able to do, and that may allow you to achieve overall lower economic cost to the system if a certain energy coming from a certain place was otherwise undeliverable. That's just one example. The other example that I think is really what will drive it, ultimately, is the resiliency benefit of being able to controllably island off pieces of the system without having to 100% fully define the boundary of that system long before an event actually happens.

Speaker 2.

Today I'd like to talk through some frameworks and examples that hopefully will help us get some perspective on how we can realize the full potential of advanced energy technologies. To get us started, I'd like to ask the room a question. In your view, what is the most important priority or principle for electricity policy or regulation? I'm going to throw a couple out there. Efficiency, reliability…

Comment: Getting the short-term prices right.

Comment: Why is that not a surprise, because that's the number one objective of this room? [LAUGHTER]

Speaker 2: OK, well, hold onto that thought. We're going to get back to it in a couple of minutes.

So, some more examples. Technology advancements are usually deployed sequentially, and at each stage of deployment there are different barriers and challenges that need to be addressed. At the beginning, technologists will usually find a beachhead market--a niche application. It's oftentimes not the intended customer. It's oftentimes not scalable, and usually it is a high margin application. And then they'll make their way to a limited utilization use case, where then they're focused on the intended customer, but it's on a trial basis, or it's a very narrowly-defined application. Getting from stage one to stage two requires technical validation, and that's something that ARPA-E and others have done fairly successfully. For example, in network optimization, which Speaker 1 talked about, power flow controllers, micro synchrophasors, and machine learning, such as AutoGrid, have made their way to the limited utilization stage successfully.

Deep transformation is where fundamental shifts affect a broad range of different stakeholders in significant ways, and getting to that stage requires policy change. And it's very difficult to do that, because of path dependency, because of vested interests, because of risk averseness. And that's a place where HEPG can certainly play a significant role. Some past successes might include alternating A/C power; it might include mixed-integer programming, advanced metering infrastructure, and so on.

What I'm showing here is the transmission topology control from NewGrid, which is currently at the limited utilization stage of deployment. They started off doing mostly offline services, things like reports to ISOs, mostly MISO and National Grid in the U.K., to help figure out things like outage scheduling--what's the optimal time in place to have a planned outage to do a maintenance on a power line? They were able to make their way to reliability options, notably in ERCOT, where they're working on remedial action schemes by working, for example, with PJM to do a large-scale simulation study where they were able to retire the technology risk and build operator confidence. Where they are struggling, however, is getting to the deep transformation stage, which would essentially entail changing market operations, so here we're talking about changing the way OPF (optimal power flow) is done, changing price formation, locational marginal prices, restructuring, financial transmission rights, and doing that requires policy change. We need to look at social net benefit, get stakeholder support, revise marketing designs, and so on, and it's obviously much easier said than done.

So, now think about that most important priority you thought about when I prompted you initially, and now think about this question. How do we leap from limited utilization to deep transformation? What principles should we use to make that leap? And my suggestion is that we need to radicalize incumbent priorities by fully utilizing technology progress, and I'm going to unpack that a little bit for you. So, I'll say that again. Radicalize incumbent priorities by fully utilizing technology progress. What I mean by "incumbent priorities" is, most likely, what you thought of when I asked you earlier. It's something that's mandatory, it's requisite, it's imperative, it's a foundational principle of electricity policy and regulation. It's often used as a justification to bar technology adoption, and it's also a source, oftentimes, of path dependency, vested interest and risk aversion. But it doesn't have to be that way, and this is where the radicalization comes in. So, to radicalize comes from a place of absolute commitment to meeting the priority in the best way possible. So, it's a fundamental overhaul which is a far-reaching departure from established norms but very much focused on that principle. So, these priorities are not going anywhere, but they need to evolve on pace with technology progress. Something to think about is that the best policy and regulatory decisions were made with the technology possibilities and assumptions at that time. And technology evolves very rapidly.

So then you might be asking, "This is all great, but what do we do with this information? How do we radicalize our priorities?" Well, let's take an example. I'm going to take a stab at radicalizing reliability. There is a study that was done by the Brattle Group for ERCOT back in 2013 to try to estimate what the economically optimal reserve margin would be. It was done based on 7500 different scenarios of full annual simulations, including every hour of the day, and it goes from a 6% reserve margin to a 17% reserve margin. On the chart you have capital costs in pink and production costs in purple, and if you look at just the capital costs, as the reserve margin rises from 6% to 17%, it's about a billion dollars of annual cost difference there. So it's fairly significant. The top band is the cost of scarcity. The cost of scarcity increases as the reserve margin becomes less and less. In talking about "cost of scarcity," we're talking about involuntary load shedding, we're talking about ancillary services, demand response, imports and so on. This Brattle analysis found that the optimal reserve margin is 10.2%. The report also stated that if Texas were to adhere strictly to the one event in ten years reliability standard, the optimal margin would be 14.1%, and in 2016 ERCOT ended up going with 13.75%.

This study is the best example I found that really meets the incumbent priority of reliability, because it's a probability-based model. It looks at a broad range of factors, and it's based on an energy-only market design. But then the question I have is, how do we radicalize this analysis and other reliability analyses by fully utilizing available advanced technologies? First off, resource adequacy was OK in the 1950's, but we now have ways to provide reliability differently in 2017, so because we focus on resource adequacy we build excess generation and transmission capacity while operating the system conservatively and excluding new capabilities of emerging technologies from being tapped into. So one way to radicalize reliability would be to change the focus from resource adequacy to something like system flexibility, which would basically be robustness to uncertainty. This would allow emerging technologies like network optimization, storage, and demand-side management to be more fully utilized, and it can be done in a centralized dispatch like in the Southeast, or it can be done with efficient signals in a deregulated state.

The other thing that could be radicalized in the way that we work with reliability would be to improve the way that we model resource planning. Currently, resource planning models do not use the best capabilities that we have at hand for a modeling simulation. Oftentimes, even when there is a power flow model that's somewhat detailed and sophisticated, a lot of the new technologies are excluded, or they're modeled incorrectly, because of conservative assumptions around how they're going to be dispatched, and it would change the analysis significantly if we were to just change the way that we do resource planning and modeling, and it might even unlock some of the $34 billion there that's not on this chart and put more resources in play, saving costs while improving reliability. And this is especially transformational for distribution, because at the distribution level we're really just getting started with modeling and simulation.

And if we really want to get radical we could have a hard look about who should provide reliability in the first place. The value of lost load changes dramatically from one customer to the next, and the reliability standard basically makes it such that we're all paying for the value of lost load of the most critical customers. So if, say, customers with a value of lost load above ten thousand dollars per megawatt hour were to provide their own reliability, that might change the calculation significantly. It's quite radical to talk about that now, but with the speed of evolution of distributed energy resources, differentiated reliability might very much be on the table sooner than we think.

So, to conclude, I'll talk about a few steps that we can take to implement radical priorities. First off, correcting market failures and distortions. The FERC storage NOPR that came out last year is a very good example of this. They had a very thorough stakeholder engagement process where they listed, essentially, a lot of market failures--for example, resources needing to be running and synchronized in order to qualify as spinning reserves.

Something else that could be done is to override some stakeholder-driven processes. A good example of that is the ERCOT Future Ancillary Services taskforce in Texas, which was looking to reform the way that ancillary services are compensated by breaking out fast-acting and regular ancillary services, which would have compensated storage, and demand-side resources, that are much more nimble, adequately. And this was widely supported by ERCOT staff; however, unfortunately, industry stakeholders shut it down, for obvious reasons if you look at what they're struggling with. However, it was a shame.

Then, finally, it's possible to allow more of the risk to be taken on by participants. Again, Texas is a great example of this, with the competitive retailing environment. Now that we're looking at grid modernization in places like New York at the distribution level, ostensibly we could think about allowing participants, much like merchant transmission, to own feeder capacity and deploy capabilities such as sensing and measurement, and then own it, with mechanisms similar to FTRs, which would accelerate deployment of those technologies and spread the risk. And that's my presentation.

Question: You were talking about, with the Brattle study, how the optimal level of reserve margin was calculated, I think, at 10.2%, and then I think you mentioned that to achieve the one event in ten year criterion, the optimal reserve margin would be 14%. What's the probability of an event at 10%? If you don't have it, that's fine. I was just curious.

Speaker 2: I'm not sure what the probability of an event would be. If you look at the NERC standard, it would be a little bit more than one event in ten years, but it wouldn't be much more than one day in ten years. I'd have to pull up the report, but it's in that ballpark.

Question: Are you suggesting that we eliminate the stakeholder process and let the RTOs become utilities? Because that's what they are without the stakeholder process.

Speaker 2: I'm suggesting that when there's an obvious improvement to regulation, the regulator should exercise leadership and step in and override some stakeholder decisions-- when it's in the best interest of the customer, society, the electricity system, and so on. So, basically, a regulatory override of stakeholder-driven processes. And, ideally, an entirely new type of process that perhaps is less legislative that allows smaller players who are not the large incumbents to have more of a voice—a process that is more empirically driven, and that's where improvements and simulation and modeling can be really powerful, because if the subcommittee and committee meetings at ISOs were based on empirical evidence from a model that models the physics and devices and transactions and so on, then it would be a lot harder to make an argument against something that's obviously a good idea, because everyone would be working from the same data set and we could test assumptions.

Question: I don't know if you follow PJM closely enough to answer this, but in terms of resource adequacy, a lot of time has been spent in the stakeholder process, for better or worse, over the last few years, to integrate almost all the "new technologies" that you listed into the resource adequacy construct or reliability pricing model--that's storage, distributed resources, energy efficiency, demand response… I'm trying to figure out what it is you think PJM has overlooked at this point.

Speaker 2: What I'm saying is that if the main metric that you're looking at for resource adequacy is the reserve margin, you're not focused on system flexibility to the extent that you could be. So you would change the metric from reserve margin to robustness to uncertainty, essentially by running a Monte Carlo, or you could do something different. But talking about advanced technologies in the context of resource adequacy is very unfair, because resource adequacy, at the base, is excess capacity, and new technologies allow us to not have to necessarily use excess capacity to meet our reliability goal.

Question: I think you might have just answered the question; I'll make it a little bit more explicit. Were you suggesting that that optimal reserve margin from the slide might actually be lower, once you have truly dynamic efficiency benefits over time, unleashing this radicalization by getting the prices right and creating incentives?

Speaker 2: Yeah. What I'm saying is that the way that the Brattle chart showing different reserve margin costs was done, and the way the analysis was run, was based on assumptions where the cost of scarcity is very high, because we're not utilizing advanced technologies effectively. And I talked about the bottom part of the chart, where you have the capital costs and the production costs, and then the upper part, which is the cost of scarcity, and it skews very much to the left. It's big on the left (at lower reserve margins). What I'm saying is the chart might look much, much more flat, and a lot of the costs that are included in the calculation of the costs of the minimal reserve margin--a lot of those costs might very much be at play. The cost of transmission and the cost of existing generation, the way that it's dispatched, might look very different if we fully utilized the advanced technologies, and if we model correctly having a full A/C power flow with transmission topology control. So the costs might look very different, because if you're fully utilizing the batteries, and if you're not doing involuntary load shedding, if instead you're doing active demand side management, if you're changing the topology of the transmission system, then your cost of imports would go down. If you're providing localized reliability with a radial feeder system like what Speaker 1 was talking about, and you're differentiating reliability by having on-site generation for people who have a very high value of lost load, then you're also going to have a much lower cost of scarcity. So it's by implementing all of these radical approaches(not so radical, relative to the incumbent priorities, but radical relative to the way that we've been pursuing them) you are basically committing to the value of reliability, and saying that we want it the best way possible, we want it as cheaply as possible. Well, if that's true, and you really hold that value dearly, then go and look for the technologies that are on the verge of being ready for full deployment, and demand these technologies.

And this comment is to the economists in the room and the policy makers and folks who have been doing this for decades. Challenge your own vested interest in your own ideas. Don't be afraid of being wrong and going back to the basic principles that you felt as true your whole career, essentially, and approach the problem with the eye of your smartest graduate student, and try to really fundamentally rethink the way that you're satisfying those principles.

Question: You were mentioning that you have an idea of replacing resource adequacy with system flexibility, right? How do you quantify that?

Speaker 2: Robustness to uncertainty. So, if you have a really good model, and you're able to simulate effectively, then what you do is you run all the possible scenarios, and you expect that the likelihood of having a system collapse would be very small. Excess reserves are a proxy for robustness to uncertainty, but they're a very incomplete proxy, and we've seen that with the whole capacity market issue of performance incentives and steel in the ground. But even that only gets us a very small part of the way, in terms of having true flexibility in the system and robustness to uncertainty. So if what we want is robustness to uncertainty, well, then, let's measure that. And we now have the technology to be able to model it effectively.

Question: You got my attention when you said "economists," so I'm going to ask you a question that's clarifying and maybe also directional. When you speak about this evolution of radicalization, what would you say, based on all your work, that the future price of electricity would look like, compared with today's prices?

Speaker 2: Well, I think in the future the service provider is going to have a much more important role in taking on the risk and the reward, so I think that the price volatility could be quite extreme, frankly, because if you have sophisticated companies that are well diversified hedging on behalf of customers and also getting operational hedges from both the demand side and from operating power plants, and if you have a lot more flexibility in the network, if you're reliving congestion, and you have a wider balancing area, then you can basically completely lift all bid caps, and you're no longer imposing an unfair burden on society by doing that, because, ultimately, the people who are participating are in it for the risk and the reward. So I would go full Bill Hogan on this one.

Question: I think we just found the theme for the meeting this time. Going full Bill Hogan. That's beautiful. It brings a tear to my eye. I want to come back to something you're talking about in terms of thinking outside the box. The technical issues are one thing. Have you thought about the economic incentives and how you try to get those changed so you can implement these technical solutions, number one? Number two, have you contemplated the political ramifications of unintended consequences? Something to think about.

Speaker 2: Yes.

Moderator: OK, we'll take that as point taken [LAUGHTER]. And we can get into that more in discussion. We'll move on to Speaker 3.

Speaker 3.

Thank you very much. I wanted to start off stealing a slide from a colleague at Pacific Northwest National Lab from that recent movie, *Arrival*, which suggests that the way we think is influenced by our language, and actually I trace that idea back to a sci-fi author, David Brin, who basically said that the language that you use precludes certain thinking and certain ways of thinking. So one of the questions that I bring here is about whether grid modernization is somehow limited by the way we define our grid objectives. And is our ability to collaborate (because this is a massive social collaboration) limited by a lack of language, or defects in our language?

So, with that, I'd like to move into my presentation a little bit. When we focus on the electric grid, all of the qualities that the network brings to energy are the qualities that we focus on, and those qualities are derived from an increasingly interdependent infrastructure, and the way we maximize the utilization of any one of these infrastructures is by increasing its interdependence with other infrastructures, and that brings with it benefits as well as risks. And within the grid itself, we also have to contemplate doing that. So, obviously, with multiple infrastructures, we see all of them influencing the other, from IT to water to electricity. Within the grid, I think one of the major challenges that we're faced with is that we're going from sort of a linear analysis, or something that's capable of being parsed through linear analysis, of safe, reliable, affordable electricity to adding other important variables to the equation, and so now it's more like six or seven variables.

What I wanted to emphasize is that when we come into the policy arena we are working on optimizing to a set of variables that increases the complexity of our analysis, and at least from our side we've come to the conclusion that some of the analytical tools and some of the processes that we use to analyze our structures, not just electrical but organizational, fall short of providing the clarity of how to balance these objectives as we implement them. And so, to a certain extent, we talk about grid architecture being an emerging discipline, and it's not the architecting, it's not the structuring of the electric system physically. It has to do with how we perceive the regulatory structures, the policy structures, and the business structures such that those characteristics are imbued throughout, so they're actually designed into the construct of the system. So we have been working on building up this discipline of grid architecture. We used it initially to good effect in the Quadrennial Energy Review, and we've gone on to develop it more and get some more practitioners of it. But, essentially it's applying sort of a consciousness of design and a disciplined understanding of the way our systems work from a first principles kind of arrangement. And the foremost spokesperson for that is, of course, a gentleman named Jeff Taft. He was heavily involved in New York REV and helping to diagram and set up the way entities relate to each other to ensure that REV was going to get the system qualities it wanted through the structures that it was creating. And that's an important thing I wanted to set out. At the very top, we need a new way to understand and ensure that these qualities are being imbued into the system.

At this point, I'm going to move onto something that Speakers 1 and 2 have covered rather well, which is that there's a tremendous amount of flexibility out there. There are huge amounts of data. We have existing controls, and we know they need to be supplemented. Meanwhile, the world is moving on. The world is choosing new technologies and new IT capabilities and new communications that are changing the bottom of the system as fast as we think about changing the top of it.

So, a quick question is, where are we going? A lot has to do with DER integration and all of the new technologies that we're talking about, and then of course the control technologies that Speaker 1 was talking about, which are in response to the volatility that we're creating in the system. But, ultimately, the place that we see ourselves going is to very high DER adoption. And the way to appropriately integrate that into our systems is through transactions and market operations. We're not in a country that favors unilateral control of things that we own. And so that's something that we have to come to grips with.

And I just wanted the Future of Electric Utility Regulation series that I think Paul Centolella has been involved in is really a great source of thinking on this issue.

So, we've got these shifts going on. That's what the other speakers have spoken about, but the opportunity, of course, is that there's a tremendous amount of addressable flexibility, if only we had the mechanisms to do it fairly and safely and result in a smooth, predictable, reliable system.

So, taking a breath from architecture, one innovative technology is transactive systems. That is where you're trying to use those market mechanisms at a new level of resolution in the system to replace the services that some of the big iron of the grid has traditionally provided and to turn the control service of the grid into a multiparty service that still has to produce all of the system qualities that we expect it to produce in order for us to find it acceptable, as a society. Obviously, LMP is a fantastic example of a transactive system, where you're using price to influence the engineering control of the system. However, to apply it at the scale that we're intending to apply it, comparing LMP to that is kind of like comparing an x-ray to an MRI. We're doing it at a different scale, and by doing it at a different scale, it's not the same, and so there's a lot of R&D that's necessary to make sure that we're doing it correctly.

What we're trying to obtain is scalability. We want to be able to optimally incorporate multiple objectives of the stakeholders, and respect the sovereignty of the ownership of these devices and assets in the system while recruiting them in through value-based incentives. So that is ultimately the goal of what we're trying to do through this transactive mechanism. And, ultimately, we want it to remain faithful to those system qualities at the top, and so that's why we sort of continuously maintain that focus.

In order to pursue the flexibility possible through distributed resources or through to the transactive energy mechanism, economics and engineering have to meet a lot more often and a lot lower in the system. And so transactive energy events, which would occur at nodes all the way down to the customer, potentially have complicated physics dynamics, as well as economic preferences that we need to understand. We need to come up with new metrics to ensure that we have optimality from an economic perspective, and it's no longer a linear calculation. We also have to do a little bit more fusion of economic theory and control theory, which we are funding in our R&D program. And of course this has to be tested in the virtual world, so we don't shut anybody down as we experiment with something that's quite new.

So, along the way we are trying to figure out how we make a value-based comparison between a big asset that's acquired centrally and lives for a long time and a transient market-derived service that exactly matches the services that are provided. What we found is that the valuation process and the valuation methodology that's present today is lacking. It doesn't allow us to make that apples-to-apples comparison. But ultimately, we are in the business of making decisions, and what we found is that the logical progression we have here is that decisions are supported by impacts. Impacts are the differences between scenarios using metric measurements. The metric has to be qualified by a published, available-to-inspect valuation model. And the valuation model accrues from system activities. Some of them are unique to the baseline scenario, some of them are unique to the test scenario. However, there are also a set of common shared activities. Ultimately, any activity undertaken by the system has to satisfy the objectives that the system was designed for, and each objective has to be clearly stated in the system such that we can show how new technologies and old technologies address the system objectives or fail to address them, as it happens.

Now, the interesting thing to me (which is tragic, I suppose, on a personal level) is that in order to maintain the discipline and process and the rigor, the integrity, and the transparency of the valuation process, what we found is that to get to my apples-to-apples comparison, I need a new set of documentation artifacts. I need to go back to the theme. I need a new language to express the concept that I'm trying to get at. And so, in this valuation process that we are exploring, there is a new set of documentation and artifacts required to perform an economic valuation. Not all of them need to be used at one time. If you're building a chair, you don't need computer-aided design. If you're building a house, you probably do, and if you're building something any more complex, you absolutely do. However, what we find is, with the complexity of the systems that we're looking at and the innovation of the technologies that are created, we need an enhanced set of documentation to perform a public valuation process.

Another thing that is treated in every valuation but not generally treated in a uniform, disciplined, and documented way is the treatment of risk and uncertainty. There's always a section at the back saying how well risk was treated in this, and sometimes there are graphics to go along with it. However, I think that there is a missing assessment of how uncertainty is treated systemically through that valuation process. And so we've done some work on that, in terms of taking a look at where the sources of uncertainty are in any valuation, and then at the effects of uncertainty on valuation and how we might guard against that or conduct tests to ensure that uncertainty and risk is discharged properly in the process. And, again, going from big iron in the ground for 40 years to an ephemeral, flexibly recruited service is a big question. It's a big jump, and you need to know what the risk calculus is between those two, and it needs to be expressed in the same terms.

Finally, I'll just emphasize the grid architecture and the valuation, and that I think of transactive energy as a value access mechanism, so it is an innovative technology in itself; however, it is the venue for value access for a lot of the newer technologies that we've talked about today.

Question: Can you explain a little bit more your comment about LMP not necessarily working at the distribution level? Certainly, in New York, that was the vision, that you sort of have an LMP at the distribution level. And are you thinking of something that is nonetheless centralized at the distribution level that gives price signals, or do you think we have to move away from that kind of centralized pricing?

Speaker 3: One thing that would not be changing is that we want to use price to influence behavior. And so the DLMP discussion is appropriate. With the amount of data moving through those local environments, we would expect that there would be a more decentralized mechanism to arrive at some of these prices, but some of the things that are built into the LMP consideration don't respect the distribution system's uniqueness. The distribution system currently is an unbalanced, three-phase system, where the transmission system is balanced. The other thing is that, with the number of players that we have moving through the system, there is a high level of complexity of looking at nodes that are not maintained by professionals, in terms of having to understand the responsiveness of people and their devices, as opposed to professional traders. And so we have to look at that stability. The third thing is that, when we are looking at copying this metaphor down, it brings up retail-wholesale hysteresis. You could have instability between the retail and the wholesale systems settling at the same time increments and creating instability in the system.

Speaker 4.

First of all, thank you for having me. I'm going to look at the issue from a dual perspective here. On one hand, what do we need to do in order to encourage regulatory reform to enable, basically, the incentives we need to develop and deploy the technologies necessary to optimize DERs, and how do we make viable financial models for the new market participants that will deploy the technologies necessary?

AMS is a San Francisco based startup started three years ago. Today, it has about 110 megawatts of storage committed for, and $200 million in project financing. So AMS is deploying electrical storage. They started with Tesla batteries, and basically those batteries are installed in parallel with commercial buildings, water treatment plants, and so forth, in those areas that need congestion relief, especially in the Los Angeles area, where San Onofre was retired and gas plants are being shut down.

My talk will also be informed by the perspective of GO15, an organization which includes 19 of the largest grid operators in the world. Every continent and every regulatory regime is represented in the membership.

I'm looking at the problem from both these perspectives, though my opinions are my own.

Basically when I was at PJM we started this following the Northeast outage in 2003 and the Italian blackout shortly thereafter.

We all know what the drivers are, they have been talked about—reliability, security, affordability, flexibility…The bottom line is that there is no question today that we need to evolve to answer the challenge of a highly distributed power grid, and it's a fundamental paradigm shift which has many, many implications.

The challenges to the grid operators are well known, from TSO, ISO, and RTO perspectives. We're losing visibility into the generation of the system, which is typically at the distribution level, often behind the meter. A big problem that fewer people talk about is a loss of system inertia. Every time we take electricity from conventional plants and replace it by solar generation or wind generation, we're losing system inertia. As one of the GO15 members explains, in a major blackout last September, the loss of system inertia was not the main factor or the root cause, but it was a contributing factor. At the DSO (distribution system operator) level, the DSOs are obviously not equipped to handle massive DER penetration, and with Laura Manz, we've been working in California on what is called the two bookends. We are looking at two scenarios and a number of intermediate scenarios about the future interfaces between TSOs and DSOs. So today at the RTO/TSO level we have very little visibility into embedded generation, and the question is, what do we need to do to expand the optimization and control of the DERs? Should it be decentralized, or highly decentralized? That's what we're going to talk about today.

There are a number of solutions. The key component of a solution is a combination of a portfolio of load flexibility, generation flexibility, and storage, and you need those three to come up with a workable solution. We do have new actors, demand response aggregators, more sophisticated virtual generators. We do have microgrids. The question is, how do we make them financially viable? How do we pay for the investments?

There are new grid services appearing, and the U.S. is one of the leading countries in fast frequency regulation, obviously. That was thanks to FERC Order 755 and the implementation by PJM. Synthetic inertia is something that we're looking at at the GO15 level. There's reactive support, especially at the distribution level. And, down the road, DER-assisted restoration. But, again, we need to create a mechanism to incentivize the DER to respond to the grid operator needs, and, most importantly, for the new actors to invest in storage and so forth. So what we need is a financially viable business model, not only to attract investment but also to get the DER operators to respond to the proper market signal. We need new market designs to create incentives for DER participation, but at the beginning we need the proper regulatory framework. So at GO15 we're working with regulators around the world. So that's where we need, obviously, to educate our policy makers or regulators in order to foster the integration of DER.

I'm very glad to be in the U.S., because when I compare with other colleagues from around the world, we have had, first of all, very proactive initiatives from the DOE, and we're thankful for that. I'm talking about the SunShot Initiative, for example, and as Speaker 1 introduced it this morning, there was a very interesting concept, which is the agile fractal grid, and I'm going to talk a little bit more about that.

AMS has been awarded by the DOE a grant under the ENERGISE program, and what it is for is basically PJM at the distribution level. What we have proposed, basically, is to implement security constrained optimal economic dispatch of distributed energy resources. The beauty is that the implementation of an agile fractal grid kind of approach can be incremental, and it can be self-funded, because, as you deploy fractals against multiple revenue streams, that means that they start generating revenues that you can use to invest in the next fractal implementation.

This slide is my representation of what I feel the future should look like in order to be financially viable. I forgot to say, I was a cofounder of Viridity Energy with Audrey Ziebelman before she moved to New York State, in addition to AMS, so I've been a little bit on the market participant side, and the overall conclusion I get to is that you cannot make a company viable with a single product or a single asset against a single product. What you need to be able to do is stack multiple revenues. You need to be able to put together an optimized portfolio of storage, flexible demand, and flexible generation, and co-optimize that into a virtual generator that can provide multiple services both at the RTO, at the wholesale market level, and also at the distribution level. And that's where we have one of the main barriers, basically, if you're trying to mark the services that you can provide with a battery you see little red flags. I can discuss that a little bit later. This is the AMS solution. Basically, we're optimizing the battery to provide up to six hours of load relief at designated points to the distribution operator.

Another project that we had at Viridity which I liked very much was that we essentially deployed batteries at the Philadelphia Transit Authority. Those batteries wouldn't pay for themselves in their lifetime, but by recovering the braking energy of the trains and then putting the battery on the PJM fast frequency regulation market, we were able to get a return on the investment in less than five years.

To Speaker 1's point, this is what we're proposing on the ENERGISE project. At the middle of it, there is something that looks very much like what we implemented at the wholesale market level, basically, security constrained optimization of the assets, which takes into account the power flows on the distribution system, and that optimized multiple types of storage assets of flexible loads and generation. Obviously, we need strong power analytics, too, and part of the power analytics we implement with a distributed system state estimator and some advanced volt/VAR optimization algorithms. For measurements, we are introducing synchrophasors. We need synchrophasors in particular to implement a concept of topology estimation. We want to be able to detect topology changes in real time and hopefully at the individual phase level. Dynamic line ratings are not a technology that is in need of incentives, and I can talk about that, too. Predictive analytics, obviously, are part of this, and then we have the economic incentives and the grid operator signals. But essentially what we want to do is to be able to optimize a schedule of all those assets and provide multiple services, both to the market, like I've got in this case, and to the grid operator, the distribution system operator.

Fractal optimization, at least in my view of it, it's a multilevel optimization in the organization. Basically, each fractal becomes a resource to the next level up, so at the lower level you can have a microgrid like we have in the ENERGISE project, and then the feeder optimization is attached to the second level of fractal. So we're proposing the optimization here of a full feeder, and then optimization of multiple feeders attached to the same substation, and on and on and on.

So, in conclusion, we're going through a fundamental structural change. I'm fairly frustrated, and yet I'm very happy to be in the U.S., because it’s much slower in Europe, I tell you, and in Europe they don’t have the advantage of having a nodal market that sends the right price signals to where the congestion is. They want to socialize everything in Europe. So we do have the tools, but we need to improve the regulatory framework, like FERC 755 has done, to basically foster the deployment of new solutions. Digital transformation is obviously the key enabler. The key one for me is the agile fractal grid, but regulatory reform is needed, and we need to start with that.

General discussion.

Question 1: I guess the first question I have is focused on the developer community and the people in the tech community and the digital age community who develop all these cool things and want to make money off them, and another question is focused more on policy makers and regulators.

At least for the internet, you’ve seen the great prolific use of all of the data that’s available in our digital age economy. Anyone can go and develop an app that works on one of the several operating systems. Those operating systems are visible to them, internet traffic is freely exchanged through the ISPs that are interoperable with one another, and the app developers can set up a revenue stream of their own making through some other service like PayPal. Obviously, this platform, in order to get to what Speaker 3, I think, called a multiparty surface, is a lot more complicated. There are price formations that are not in control of the developers of these technologies. It’s hard to monetize novel technologies that might be developed to achieve efficiencies, and the real time nature of the network, in everything from state estimation to the optimizing algorithms that the operators use, significantly complicate the digital landscape.

So I guess the question is, what’s the biggest problem for a developer of these new technologies? Is it access and use of data that may exist but is not transparent to them, or is it the ability to take that data, make use of it through a technology that can actually communicate with an interface into a system operator that occupies a role that’s more commanding than the role, say, an ISP or an operating system performs in the internet protocol economy?

Respondent 1: I think the single biggest problem is that if a company truly believes that something is of value and that the value can be created and captured, they’re not able to just go out and build it. And the assumption of, “Oh, right of way is a problem, and we have the utility service territory and the monopoly and all of that, and safety…” I don’t really think that’s an excuse. I think that FERC Order 1000 establishes an interesting framework in how you allocate costs, the whole beneficiary-pays framework for transmission. I think we can think about that also at distribution level.

The other thing is that information is non-rival, and increasingly it’s also non-excludable. I'll give an example. The micro synchrophasor technology that was developed at Berkeley, it’s better if you can put it at the substation or the transformer, because then you have fewer transducer errors, like every time you go through an inductive device you have a static error, and over the whole feeder you end up having pretty big errors and the math around calibrating that is still being figured out, but ultimately you can put these micro PMUs on the customer side of the meter, and then you get all of this data streaming that gives you intelligence about what’s going on in the power system, and we’re already starting to see companies that are deploying micro PMUs and are providing access to the micro PMU data through a subscription service, where then they can stack the value of the information and have a better business case.

So I think that if we were to work on mechanisms for people who really believe in an idea to just be able to go and build it, that would be a really positive step forward, because then we would have more information and just generally better technology. Or if the technology fails, well, then that's OK, too. As long, as course, as safety and so on are respected, but I think that we're far too conservative on that front.

Questioner: So it's the idea that it doesn't lend itself to the permissionless society that we hear so much about, say, in the realm of Uber.

Respondent 1: Something like that.

Respondent 2: One other thing I wanted to add is that, again, some of the work that we've done under the Grid Modernization Initiative is to try to define grid services as the services that are provided that make the grid function. One of the things that I see new technologies come up against, especially when we're looking at the distribution system, is that the grid is not designed to express a need for those services at all, even internally in its own systems, much less to publish those needs in a way that could be addressed by, say, an auction or any other kind of value mechanism, and so what we see are workarounds in the system. But I think one of the struggling points that we see, especially in transactive energy, is we have a very vibrant transactive energy program in buildings, and they're actually using transactive mechanisms to optimize a series of building use cases, some of which have nothing to do with energy. However, when that flexibility is recruited and ready at the building-to-grid interface, the distribution grid in particular does not have the language in place to express those needs in a way that's addressable.

Questioner: A peer-to-peer problem.

Respondent 2: Exactly. It can't say, "I need reg-op," or, "I need voltage management."

Question 2: This next question has more of a regulatory or policy dimension. We often hear at the tail end of all of the slide decks this kind of bromide about, "Well, of course regulatory reform is necessary, of course." And I guess Speaker 1 has even included it as an exhortation that we "radicalize incumbent priorities by fully utilizing technological progress," which sounds vaguely Maoist [LAUGHTER]. But let's be a little more concrete, and I'd like all of the panelists to respond. What are just one or two concrete things that, say, state regulators, some of whom are in the room here today, should be asking themselves if they want to get to the place that all of you have described, of making basically what we have already more efficient and not overbuilding this and achieving less efficiency through old ways of doing things?

Respondent 1: Ask, what am I afraid of? What am I afraid to let go of? One, explore the fear, sit with it, and ask yourself, how can I attract the smartest technical people who can do the best work at my commission?

Respondent 2: There is a solution that works well in Europe right now, in particular in Belgium. It's called dynamic line rating. Dynamic line rating has been able to increase line capacity by up to 70% for a certain period of time. That would work very well in the United States, especially where we have organized markets, like PJM. The reason it would work very well is that when you clear the market, taking into account the physical constraints of a system, right now, those constraints are seasonally adjusted and static. If we had the regulatory reform, as you say, necessary to align incentives with investment, we could get a lot out of the system and reduce the LMPs when congestion occurs. But it's not happening right now. PJM would be very interested to see ways of reducing congestion, but you have to go through the TSOs. And where is the motivation for a TSO to add more equipment on their line and create more signals, interfaces, and things like that? They told us that currently they are not interested. They get a fixed rate of return.

Questioner: So, incenting a more efficient use of capital.

Respondent 1: Sometimes, though, even when you have the best intentions, it doesn't work out. For example, the Energy Policy Act of 2005 had very clear directions to FERC that they should ensure the deployment of advanced transmission technology, and that was in 2005. And you look at the list, and it's really comprehensive. Everything that ARPA-E's ever done is on that list for transmission, and then a bunch of things that ARPA-E hasn't gotten to yet. So the person who wrote that really knew what they were talking about. And then there was an order at FERC, I think it was 679 or something like that, that implemented that mandate by saying that you need to have ROE (return on equity) adders on advanced transmission technology, you need to make sure that all alternatives have been looked at when you make an investment, and then also things like accelerated depreciation and work in progress capital for traditional transmission projects.

Well, what ended up happening is that they ignored the ROE adder. They didn't do the proper comparison of alternatives, and they justified that by saying, "Well, we have the accelerated depreciation, and we have the work in progress capital, so there's no problem here. We'll call it a day." So essentially, even though there was legislation and regulation, it wasn't implemented properly.

Respondent 3: First, I think we should learn to embrace and celebrate failure. Not everything's going to work. We're going to learn this in steps, and sometimes we're going to take two steps forward, and sometimes we're going to take two steps backwards. But we can't learn unless we embrace that, and we need to make people whole, and we need to encourage some level of appropriate experimentation, but be very explicit about the risks associated with it, the downside, the upside, and think it through very carefully, and there's a whole field of probabilistic risk assessment and decision making under uncertainty. A lot of those concepts, I think, become a lot more relevant in the world that's emerging.

My second point is around the data issue. I think we need to have a very explicit discussion on what data is sensitive, and why, where, and when. So, today, we're very, very protective of all data under all conditions and all scenarios, and if pressed to ask why, we can produce arguments around security, and we can produce arguments around privacy, and we can produce arguments around business proprietary information, and all of those things exist. Those are very valid and real concerns for some subset of the data that we have and produce regularly in this industry. And let's identify those particular items. Let's protect those particular items. And then the data that we decide explicitly that we can share more widely should be shared more widely to enable those new vendors to really estimate the impacts and value that they can offer.

Respondent 4: Well, we're going about this period of intense modernization. Everything is dynamic. Utilities are gaining really incredible capabilities in their distribution systems and control systems, and the question that's come to me many times, from the regulatory standpoint, is, where's my analytics? Where's my killer dashboard? Where's my dynamic assessment of the system? I think that much of the work of regulation is where the dollars meet the road, and so it has to be in rate cases and things like that. But regulators work more than full time already, and so it just occurs to me, where is the daily, weekly, sort of the continuously dynamically updated evidence of oversight that I ought to be provided from the folks that I oversee? And I think that that's a question that's still wide open, because, "where's my dashboard?" has been around for quite some time, and with the job that they have, I think they deserve a little bit more visibility in the system.

Question 3: I do have a question, but I want to start with a kind of quasi-statement, quasi-question, and that is, I listened to this, and in other forums they talk about all the whiz-bang new devices and methods, which I think are good. The question always comes back in my mind, well, what's the benefit for the customers, the folks who actually consume electricity? What's the benefit to the system? Does it reduce costs? Does it improve the quality of service, the quality of power, reliability? Reduce line losses?

That then leads me into the question. I heard from a couple of the commenters, "Well, the problem is who pays for the R&D, who benefits;" another panelist said, "How do we pay, how do we finance this investment?" And one of the things that I keep wondering is, why, in the electric business, does this come up? In every other major industry, where billions are at stake, whether it's oil and gas development and delivery, whether it's chemical plants, the companies make the investment and they look to recover it in the market, and to the extent it benefits, it goes to the shareholders. And in a competitive space there's a bit of that in the electric field, or more than a bit of it. In the regulated space there's this almost knee-jerk reaction from all the regulated industries, "Well, we'll spend money on anything you want us to as long as you tell us we'll be entitled to recover it." And it's almost, to me, a psychological problem. And in the competitive space, I think, at least we're dealing with it, because, whether it's generation side or retail side, they're exploring, and it's a matter of individual cost-benefit, and it seems to me that may be a more efficient way to do it, because I just know the times that the utilities have asked us to make certain investments early on in new technology, it turns out that's not what customers really wanted. The best example (and I use it a lot, and it's probably unfair now, and stale) is back when we first rolled out advanced meters, and the utilities came in and said, "We've got to show why this surcharge on customer bills is necessary [the two dollars or three dollars.] And if we give them these in-home devices, then, by God, they can see their consumption." That would have been six million of the most expensive paperweights ever distributed, because what people ended up using is their smartphones and computers and that kind of stuff. But it just seems like the R&D investment at the beginning, whether it's DOE or others, is one thing – but when you go to commercialize it, is there some way other than putting it always on the backs of rate payers, to the extent it's in the regulated space? And, again, I'm not suggesting that it can't be included in rates, but what's the real impediment? Why is this unique in this space?

Respondent 1: So, my understanding of the regulatory compact is that we have, say, a monopoly and a regulator, so that they'll be exchanging information, and then the regulated company will go to the regulator, and they'll ask for permission to do something, and they should be proactive in doing that. So, if you have one company and one regulator, that should be a very open dialogue.

Where you have a situation where people say, "Well, I'll only do something if the regulator tells me to do it," well, I would expect there would be a hundred companies and one regulator, where they all get 1% of the airtime. So, to me, there is a big issue there. And you look at companies like Exelon and Southern Company and others, they have a tremendous capability for lobbying, and they really know the regulatory system very well, and they have a tremendous amount of influence, but it's just what they choose to use that influence for, whether it's keeping your nukes running through the capacity market or some other thing like that, instead of modernizing the system. So that's my first point.

My second point is that if somebody's willing to spend money, like the examples you were giving in the oil and gas business, and so on, if somebody's willing to spend money, to take a risk because they think there's a reward, they should be allowed to do it. However, in the power sector a lot of times, people are not allowed to do it. And I think part of the reason why is that you have this spectrum from fully regulated monopoly to fully competitive Darwinian ecosystem, and so, on the Texas end of things, the Darwinian end of things, investments happen. People are allowed make investments, take on the risk, and so on. On the other end of the spectrum, hopefully, most of the time, the investments also happen, because the one company that has the franchise territory doesn't have to worry about spillovers from innovation. If they take a risk, there's not going to be a bunch of little fish coming and nibbling and taking away their upside. But it's when you're in the middle, when you're stuck in like a New York or something like that, where you have a regulated monopoly, and then you have a bunch of third parties who are vying for access to the market, then you have a bit of a tension there.

Questioner: I understand that, but it's the psychology that, "Unless we know in advance that we're going to get recovery we're not going to make the investment." And that, I would submit, is peculiar to the regulation space. Because, most of the time, they don't need permission. They want permission. Not only do they want the permission, they want to be told in advance that it's prudent, not only that the investment is prudent, but the way they invest it is prudent, so it's an attempt to shift everything onto the ultimate customer, as opposed to something else.

Respondent 1: Yeah, so I'm thinking through three failures. The first is, if you're a regulated entity, you should be proactive in working with your regulator, as you're saying. The second is that either you're competitive or you're regulated. In between is going to cause some tension. And then the third is that, especially in the context of R&D, the point is that you're going to fail a lot. So there should be the expectation of failure, and you were pointing out the example of the six million dollars worth of paperweights. Well, there was no way to know that smartphones and computers would provide the exact same service. So, the service to be provided was correct. You look at Opower. They get a 3% reduction behaviorally in energy consumption in residential customers. And part of the reason why they get that is that they're able to tell the customer what their energy consumption is compared with their neighbors. Perhaps you don't want to have an in-home display, but maybe the in-home display would be useful to know when you're in a critical peak pricing period, or then you could get a text message. So the spirit of that idea maybe wasn't wrong, but there would've been a failure along the way. It would've cost some money, but ultimately there's the expectation of failure when you're trying to experiment and do new things. And we need to become a little bit more comfortable, I think, with the idea of failure.

Question 4: So, even in Texas, obviously there's a monopoly on one of the things that has been discussed this morning is an algorithm that can optimize line switching. In that example, what is the commercial barrier there?

Respondent 1: I don't have a comprehensive answer for you, but let me give you one example of a difficult situation. And let me state this generically, because I do think it's a pretty generic problem. Let's assume we have a company, and they've come up with a fancy new algorithm that could be used by system operators to reduce congestion, substantially so. And let's assume, hypothetically, that it's actually 50% of congestion that they think they can eliminate via a software algorithm improvement. Let's just say. There's one view of the world where they're producing 50% of congestion reduction, and if rolled out nationwide, that's a billion dollar-plus market that they're addressing. And that's interesting, right? So I may actually be able to get private financing, which would enable me to do all the work to take those algorithms and wrap them with the commercial robustness and reliability that would be required to operate at scale. But if I'm not allowed to actually capture a significant portion of the actual congestion reduction that I'm enabling, then I'm just another software vendor, and all the ISOs and RTOs and utilities, etc., have expectations around what it costs to deploy software. It’s so many engineer hours. It’s so many customization hours. And there’s a relatively small number of customers in this industry, right? We’re not talking 300 million users of your software, we’re talking a couple dozen, perhaps. And so now, instead of a billion-dollar market that you’re addressing, that may be a $50 million market. Well, with a $50 million market, you’re not going to be able to find financing anywhere. You may get lucky. You may be able to bootstrap yourself. You may be able to survive, but it’s far less likely that you will survive.

Now, what makes this really difficult is that software deployment model, where you’re a software vendor and you’re just implementing and customizing a piece of software, something we’re all very comfortable with. The alternative is to say, “Well, I'm going to give you a substantial fraction of the value that you’re creating through the reduction of congestion,” which requires us to create some sort of counterfactual. And that’s a whole wormhole that we really don’t want to go down, of how do we define, how do we calculate, how do we regulate what that counterfactual is? How do we recalculate that counterfactual in the context of other technology innovation that follows, and how long do we allow that to last? So, it’s sort of entirely unviable, either way you look at it, where on the one end the company can’t survive, and so you’re never going to get those algorithms. On the other end, we create such a regulatory and policy mess of trying to create that counterfactual that we just would never go down that road. Just one example.

Question 5: Excellent panel. I want to compliment each of you, because I think you each added something to the dialogue. Speaker 1, in terms of introducing power electronics which we often ignore, and your agile fractal grid, which is a great way of talking about where we’re going. Speaker 2, bringing us back to the question of whether your resource adequacy has to be a common pool resource or could be a private resource, and then developing at least the initial concept of something I saw a couple of weeks ago with some work down at Georgia Tech looking at the development of a resilience metric, that is, actually looking at doing some Monte Carlo modeling and figuring out what the value of lost load would be under a range of scenarios. So, interesting piece. Speaker 3, we of course talk a lot about DOE’s research agenda, and I think you laid out some very interesting points about how do you begin to integrate this notion of fast power electronics on the edges of the grid with more distributed market mechanisms with our conventional security constrained dispatch and unit commitment. And those are important questions to figure out. And, finally, Speaker 4, talking about the regulatory piece, which as a former regulator I think about a lot.

On the question of how do we get past this, one of the things is that we end up socializing a lot of costs, including on the distribution system, but also in our market mechanisms. Maybe less so in Texas, but we still do that. Anytime you do that, you then create a need for investment, and once you create a need for investment, you also create stakeholders in that investment, and you create a kind of institutional problem with making change.

And so, I am curious what each of you think about what the road map is. What are the next steps, going forward, given that we are probably looking at a ten or 20-year evolution to get us to some of the futures that you’re talking about? What are the next steps that we should be talking about, over the next few years, to begin to get us further down the path?

Respondent 1: Yes, and what is the value to the end consumer, when sometimes there is a time lag involved?

But there is another important question. You talked about the quality of service, and there obviously is some very appealing technology. Battery storage, especially, is great in terms of reliability and things like that, but there are all kinds of advantages that you can get out of the new technology. The question is, how do you value them, and one exercise that is being undertaken by GO15 is to determine the basis for the valuation of new services, whether it's at the wholesale level or at the distribution level. And what is the value of voltage reduction, CVR (conservation voltage reduction) for example? Well, there is a typical example. At the feeder level, you use smart inverters to level the voltage through the feeder. That enables you to lower the voltage by, say, 5%, and that results in energy savings. But, again, it needs to be socialized.

But what is the value of synthetic inertia? Synthetic inertia is a concept very difficult to comprehend if you don't understand the physics of a system. It's very difficult to explain, yet synthetic inertia is going to become more and more important, unless we accept outages and blackouts. What is the value of automated restoration, DER-assisted restoration? All those things need to be examined, and it takes time. It's taking time.

Respondent 2: We need a uniform framework for looking at that valuation process, because one of the things we found, both in the QER (Quadrennial Energy Review) analysis on valuation and the GMLC (Grid Modernization Lab Consortium) Foundational Project and my own work, is that we've got a value of everything, and we can do a value of everything. But each measurement system is unique, and each process is a work of art, as opposed to a work of engineering, and so it's not subject to the discipline that I see in the accounting profession, where the accounting profession has GAAP (Generally Accepted Accounting Principles), CPAs, and third party audits. GAAP establishes the process, the principles, the methods and methodology. The CPAs are the accredited professionals who apply the GAAP, and third party audit is the party that uses the transparency artifacts that are produced by the first two to validate the process. So, ultimately, when we're looking at valuing newer and newer things like synthetic inertia, it ought not to be a value of itself. It has to be on some kind of a comparable framework with the other services that we're looking at, and so that's our biggest next step, to see if we can produce generally accepted valuation principles which can apply to a variety of scenarios.

Questioner: Is that general, or is that specific to specific deployments in your mind?

Respondent 2: A specific deployment will always have an effect. So, obviously, you can't do a value of solar on one deployment and a value of inertia on another and expect to compare them perfectly. But there are a lot of processes that are custom and bespoke now that ought not to be, to a certain extent.

Respondent 3: I think the single biggest thing we should all be thinking and talking about right now is ownership of risk and reward. I talked about it in the context of reliability. So let's take the Southeast. Southern Company acquired PowerSecure. It's a very interesting investment, very novel. But I think where the front lines are going to be is the role of energy service providers, and this is most prominent in Texas. I think energy service providers are going to be extremely important in getting better price efficiency, so, lifting the bid caps. I think they're going to be extremely important in developing new business models where you can diversify risk. And by risk, I'm talking about commodity risk, so, the price of natural gas and so on. I'm talking about performance risk, being able to deliver what was promised. And I'm talking about credit risk, customers defaulting on their bill, counter-party risk in the markets, and so on.

And the energy service providers have operational hedges. They operate power plants. They now have operational hedges on the demand side. Demand side management, distributed energy resources. They're diversifying across different customers, so then they're managing their performance risk by having portfolios of virtual power plants. They're diversifying their value streams. They no longer only operate at the wholesale level. Now they're starting to offer feeder-level services---power factor management, fractal grid, reliability, things like that. So these are really the guys, I think, who are going to be truly innovating and enabling a lot of what we're talking about here today, because they have the relationship with the customer, at least in the deregulated states, and they have the sophistication to be able to be exposed to a lot of volatility. They have the scale and the financial wherewithal to handle the risk, and they have the hunger to go and make money.

Respondent 4: First, I think we probably will not have the luxury of being able to do this via roadmap. These things are already happening, and people are solving these problems in bits and pieces, in pilots, in some areas where the problems are coming up first, and that's going to continue to happen. I don't think this is going to be a top down process, where we're defining the vision and all shall now implement. It's going to be incremental. It's going to happen.

So, how do we manage that process and not allow it to become chaotic, and actually learn from it? Two things. First, let's really think about where the specific is generalizable. We've actually found this very successfully at NRECA (the National Rural Electric Cooperative Association) over the last couple of years, if we do a pilot project or an implementation with 12 to 15 co-ops throughout the country. We did this in solar photovoltaics around community solar programs. Each of those projects at first looks very different. The culture of the individual cooperative is different. The size of the cooperative utility is different. The regulatory environment in which they exist might be very different. But once you've done 12 of them, you find that there's actually more similarity than there are differences. And we can pull together a lot of those similarities, and we've documented that in best practice guides that cover everything from the engineering to the marketing to customers. And those guides have become really popular and very useful to the rest of the membership that we have. So we need to be thinking about how we leverage every specific example we're seeing today, no matter how small, and how we make it generalizable into the future.

The other thing is, we really have to avoid thinking along the lines of, "We've always done it this way, therefore we shall always do it this way." And that's easy to say and really hard to implement, but it's going to be something that small innovative transformative companies do every day. They pivot from one thing to the next. And, obviously, the regulatory environment's never going to be that agile, but we can instill and imbue some of that thinking into processes.

Question 6: I was wondering, Speaker 2, if you could pull up the Brattle graph that plotted the total costs versus the reserve margins. And maybe while you do that I'll pick on PJM, because I like to pick on PJM.

So, PJM, in its last capacity auction, cleared 23.9% as a reserve margin, and if you look at the reserve margins around the country, that's not too unusual. So, in terms of where we're setting the reserve margins, if we're looking at the one in ten LOLE (loss of load expectation) target as the ideal for where we want to end up, I'm wondering if that's inhibiting our ability to value and compensate flexibility for reliability purposes.

So, for example, when I ask PJM, "Why haven't we seen price responsive demand?" one of the main responses is that we don't see the price signals in the markets, and what that graph shows is that when you have a high reserve margin, the energy market's prices go down. (Well, actually that was from a different graph in that same study.)

So this is my question. Do we have to let go of the one in ten LOLE standard if we want to see more of a price signal for flexibility for the purposes of reliability? If you look at the value of lost load, could that be some sort of approximation for what folks would be willing to invest in demand response or storage or what not, if they were to see that price signal?

Respondent 1: I had a great chart for you. It's a chart that I actually got from Professor Hogan's electricity market design course, that essentially plots the value of lost load based on the loss of load probability, or something like that. But, anyway, it implies that the one event in ten years reliability standard coincides with a $100,000 per megawatt hour implied value of lost load. So, at one event in ten years, the implied value of lost load is $100,000 per megawatt hour. At one day in ten years (a 24-hour period), the implied value of lost load is about $30,000 per megawatt hour. The PJM bid cap is $1000 per megawatt hour. So, essentially, it implies that reliability is out of market. We're not even accounting for the value of reliability in the energy market.

So, the first thing I would do is radically rethink whether the one day in ten years standard is even a good standard, because all of the outages pretty much come from the distribution level. And that really stringent reliability standard is based on a very select few customers who have a high value of lost load. And there was actually a report out of ERCOT, where they tried to quantify the value of lost load, and $30,000, I think, was the highest that they found, and it was based on a small mining operation that had no means to provide their own reliability. So that was basically the type of customer that had that kind of VOLL. But for the most part, the value of lost load is well below $10,000, I think. Everybody has a different number.

There is the slide. So, if you look at the line, one outage in ten years implies that the VOLL is about $100,000; 24 hours is about – I was about right – $30,000. There's a question as to whether the optimal reliability standard is somewhere in the middle, and then the price cap is really low.

So we're kind of schizophrenic about this, because we both value reliability and economic efficiency, but in this case reliability comes at the expense of economic efficiency. We say that we value markets, but everything is driven by reliability, and the reliability is clearly not market driven. And then, most of the outages come from distribution, yet we're obsessed about resource adequacy, and we're doing close to nothing in distribution system modernization. So, really, our priorities are…we say we want something, but we're doing something completely different.

And you asked also about price responsiveness of demand. Well, at the beginning, Fred Schweppe wrote a book, *Spot Pricing of Electricity*. What most people don't know who haven't read the book is that 80% of that book is about demand side participation--frameworks of how you structure the customer-utility relationship, and so on and so forth. The spot pricing math is really just the Appendix D at the end, and that's what was picked up and people ran with, in part because it was I guess – and Professor Hogan would know this better than me – I would say in part because standing up ISOs was hard enough, and there was enough pushback that it's like, "OK, let's just have a supply side model and go forward with it," but then what happened was that there was a market power concern, so bid caps were put in place, and then we had the missing money problem, and then we ended up with capacity markets. And capacity markets are beautiful. We put demand response in capacity markets. We take away the energy signal from the energy market, and instead spread it out over longer periods of time in the capacity market, and then we say, "We need more capacity because the signals are not sufficient." So then you end up having things happen like nuclear plants surviving with capacity markets, and so on. So I think that's another area that we need to think seriously about. (I'm trying to be a little bit more provocative, perhaps, than I should.)

Comment: Capacity markets, the hothouse flowers that need constant maintenance to maintain that beauty [LAUGHTER].

Respondent 1: Yeah, so, obviously, I prefer an energy-only model. You could radicalize the energy-only model and have ancillary services, right? Have them be part of the energy market. You could reduce the time scales to sub-second. You could do all sorts of interesting things, and then, if you have service providers who are truly sophisticated, and you're using the technology that we have at hand, it could actually work. I'm going to stop there.

Question 7: Dynamic line ratings. I was looking for, given the panel topic, some low-hanging fruit that might be ready for prime time—something that's ready now that maybe wasn't five years ago that would be great for customers, and dynamic line ratings seems almost so low tech ARPA-E wouldn't even worry about it.

So, can this group of great minds do something to figure out that incentive problem? Is there a performance-based rate or some type of cost sharing, or do we revisit that rulemaking at FERC that I agree didn't result in anything improving innovation?

Respondent 1: Well, my first response is that I share your view of where that technology is. It's been around for quite some time. There's nothing hard about it anymore. There's a variety of ways you could do it. I don't know what the state of the vendor community is, who's even around offering it still. I know there were vendors willing and ready to offer it ten years ago. Have any of them actually survived, and are they still interested and willing to provide it today? And, unfortunately, I'm so new at NRECA I don't know what our membership has faced in evaluating the technology yet, but if you're interested I'd be happy to follow up with you on that.

Respondent 2: Actually, there are vendors in Europe, and some very good technologies in Europe. One of the technologies that I prefer is called Ampacimon. The company name is Ampacimon, and they go around a number of the physical limitations associated with other technology. That means you just clamp the device on the line. You don't even have to shut down the line. It's measuring the mechanical frequency in the line, and therefore it can give you in real time the actual sag within ten inches of accuracy. Not only that, but it can give you a two-hour look forward. When you heat up the line, obviously, it's not instantaneously sagging. It takes time, so it takes into consideration thermal inertia. We can build up thermal inertia in the optimization, and if we can do that, we could achieve some drastic reductions in LMP prices, which are calculated every five minutes. So the business case is so obvious, it should be a no brainer. But when you go to a TSO, they are not interested, and that's what needs to change. We need the regulatory piece to help us realign the incentives for those who benefit from it with the investment, and there are certainly some models that can be explored to do that.

Respondent 3: The dynamic line ratings technology, the network optimization, topology control, and then power flow control, like smart wires, I would pull those together into a class of investment. I'd call it network optimization and contrast it with transmission expansion and non-wires alternatives like ramping power plants and demand response. Part of the issue is that whenever there's congestion and an RFP goes out or some kind of funding or authorization goes out to relieve the congestion, every time, it specifically asks for non-wires alternatives or transmission expansion. The network optimization technology just doesn't really have a pathway to be seriously considered. So that's a real challenge.

And then, in terms of incentives, we have good mechanisms for cost allocation; FERC Order 1000 outlines it in great detail. But for something that's highly interdependent, like topology control, where the person who, say, switches their line out of service would lose money, but then the overall system would gain, there's no mechanism for allocation of benefits. And that's an area where economists, it seems, haven't really been working to figure things out. So, if we could have a mechanism for allocation of benefits, it would actually percolate all the way down to distribution system investment, because then you could have merchant substation upgrades, or merchant line sensors. You can think all the way through to that, but then there would be the incentive for somebody to say, "Hey, I'm going to put this out, we're going to be able to measure the value of it and allocate it at some point in the future."

Question 8: It seems that there's a common theme in some of these questions having to do with how, for some reason, regulators don't seem to see the value of high spot prices. But actually I think that is a common issue for this panel, and I guess my question is about capacity markets. Rather than looking at capacity or energy-only markets, there seems to be a question about wanting to get to higher penetration of demand response, DER, and frustration with how quickly we're adapting these advanced technologies. Would it help if the revenue that's collected through the capacity auction, rather than being allocated to all the load-serving entities as a basically flat fee over the year, was actually applied to the hours with high loss of load probability, so that it looked like a really high energy price, and then, if customers actually showed up and were able to adopt some of these technologies and respond, they wouldn't actually have to pay the capacity price. And then, over time, you might get the dynamic efficiency benefits that high prices are supposed to give you, without hiding them with the way we collect the capacity revenue. It's a second-best solution, but it at least makes the short-term prices look a little bit more like they should.

Respondent 1: I would say that you're describing something similar to the Operating Reserve Demand Curve, which Professor Hogan is the author of, and which has been implemented in Texas. Perhaps there are some differences, but that's effectively what the ORDC accomplishes. It takes something which could have been an ancillary service, reserves, and it makes it into a transparent market signal that will ramp in times of scarcity and be a price adder. It is an interesting thought to take capacity markets and to adapt them into some kind of additional demand curve which coincides with the times of scarcity, but then, if you're going to do that, you might as well just get rid of the capacity market altogether and have an efficient energy price.

Questioner: Well, it's a question of chicken or egg and how do you get there. So maybe one could get transitioned to the other for people who say that you need the capacity market, and they don't trust…

Respondent 1: On that point, I think part of the reason things take forever and we make lots of mistakes is that we make compromises--where we say, "We want an energy-only market, but first let's try some other thing." And then five years later we spent all this time arguing, and people put money in, and there are all the lawyers and all of that, and then we're stuck with that other thing. So I think path dependency is really a big issue in electricity regulation, and that's why I'm saying we need to be radical. We need to commit to our values and the principles that we believe in and demand from ourselves and from our leaders and so on that we implement things correctly from the beginning, or if we did it wrong, that we realize that we did it wrong, confront our fears, and change it.

Question 9: I'm going to suppress the temptation to say something in defense of capacity markets and instead talk about two other things. The first is dynamic line ratings, which I'm happy have been brought up, because, really, widespread adoption of dynamic line ratings is 15 years overdue. The Valley Group installed them on Path 15 in 2002, or thereabouts, and they seemingly have not gotten widespread adoption, even though it's absolutely correct that the rationale behind them and the economics behind them are just completely overwhelming. (Valley Group is still around, by the way. It's now owned by a company named Nexans, which I think might be a European company, so their products are available in the United States.) Why it hasn't happened is sort of a mystery.

Having said that, the other thing I just wanted to remark on is that, when it gets down to the distribution level, I am quite skeptical about new frameworks and new architectures, for reasons I've written about ad nauseam, but I think part of my major hang up about it is that the unstated premise for all of these things is that there's a lot of value in DERs for customers, for the end users. And if I could just take two of the poster children for these things, one is home batteries and one is home solar. And for home batteries, everything that I've seen suggests that they don't make sense on a daily cycling basis, and they don't make sense for backup, relative to traditional backup generators like propane and natural gas. So I don't know why we would overhaul the entire distribution system in this country for that. And then, when it comes to home solar, with few exceptions in certain parts of this country, by and large they don't make economic sense on their merits, and they only make sense through subsidies--through net metering, tax subsidies--and we now know that they increase the cost of the distribution system in order to accommodate home solar, where part of the selling point for home solar five years ago was it was going to reduce distribution costs by reducing load on the distribution system. So, at the end of the day, I'm still struggling with why we're starting the revolution, and I appreciate comments on that. Thanks.

Respondent 1: Well, I'm the first one in line for having solar on my roof, if that makes sense, but it doesn't make sense to me today unless it's coupled with storage, because, as you say, solar generation implies some additional cost to the distribution system to take care of reverse flows and things like that. So, I think that it has value. It would have value to me as a consumer, for example, as long as I had storage combined with solar. And today I haven't found a solution yet that Solar City or others are willing to sell to me. But if you imagine that distributed storage takes place, and a mechanism to pay for it, not subsidies, but the mechanism is to provide to an aggregator ancillary services either to the distribution utility or to PJM, for example, then it can pay for itself. But taking solar by itself, I share your concern.

Respondent 2: I guess one thing that I would put forward in argument with that is that there are a series of inevitable, irreversible trends in terms of what consumers are doing at the edge of the grid that is indifferent to the value to the grid. They're making decisions based on other criteria. And so, when I look at some of these things, when you look at monetizing DER in these small ways, it's not a gold mine, but the problem that distribution utilities face is that when distribution utilities invest in control assets and things that control the grid, they're making a dedicated investment for a dedicated purpose. Customers are often making an accidental investment in grid flexibility, and they're indifferent to whether they get paid half the value of it, as perceived by the market. So that's kind of the way I look at it.

Question 10: Focusing a little bit back on the customer comments, I'd like the reaction of one or two of the panel members on the degree to which customer data, data that's collected by smart meters or other technologies, are going to be helpful and important drivers in the drive towards new technology adoption, especially among some of the new players that are innovators in the marketplace.

Respondent 1: I'll address both of these questions. So, the reason why we're stuck with a coarse mechanism like net metering is that we don't have information about what's going on at the distribution level, so we don't have efficient signals that account for all of the physical engineering realities of how much things actually cost and what services could be provided or consumed, and the good news is that we have technology now that allows us to bridge that gap. State estimation is the technology that anybody who's interested in distribution modernization should be paying close attention to. AMS is doing state estimation in partnership with a company called Opus One. So what state estimation is, is you have a model of the distribution system (and most utilities don't have a very good model, but it's improving), and then you have measurements. The more measurements, the better. And you interpolate between the measurements in real time using the model so that then you can have a much higher level of detail in real time of what's happening in the system.

There's a program out of SunShot called ENERGISE, and I would encourage anybody who's interested in this topic to go and read the financial opportunity announcement on the website. It lists and explains all of this and the technologies. The program itself is brilliant, and a lot of the projects are doing some really interesting work.

Respondent 2: As one of the many fathers and mothers of the Green Button Initiative, when we're asking customers, "Can you be flexible at such and such a time through such and such a service?" ultimately, they must have the context in their possession in order to decide whether they can offer that flexibility. And so that customer data, that metering data, that previous year's behavior of their assets is the context that I think is essential.

Respondent 3: Just one quick reaction. There are two versions of your question, and I think you asked the right version. The first version is, *can* customer data be valuable in that context? I think the answer to that is unequivocally yes. *Will* customer data be valuable in that? We don't know yet, and it will probably vary culturally from region to region and place to place. We just don't know how sensitive consumers are really going to be about the use of that data, and that's going to define it.

Question 11: This goes back to a comment that was just made. The comment was, this is already happening and it's happening for other reasons. But why is that happening? Is it happening because we're not getting the prices right, and we have basically poor rate design at the retail level and uneconomic bypass? And if that's indeed the case, what happens if we do get the prices right at the distribution level? How does that change the value of all of these technologies? Has anybody actually done those studies to actually see that? We're talking about these great tools, great technology. Hey, this is really cool stuff. But have we actually thought about what the economic incentives are that are driving it today, and what happens to those incentives if we do get the prices right?

Respondent 1: There's a company out of Georgia Tech that's ARPA-E funded called ProsumerGrid led by Santiago Grijalva. He is developing a simulation studio which has a physics layer, and then the devices and controls and transactions and so on going up that provides an unprecedented level of detail to model out scenarios and uncertainties under different assumptions. So that kind of tool is going to be invaluable in making the types of determinations that you're pointing to and also in collaborating around making sure that the assumptions are correct and so forth.

Question 12: So, I have a very uninformed and naïve view about cybersecurity, which is probably why I just am concerned that the more you digitalize the grid the more vulnerabilities you open up and the greater the cybersecurity threat is. So, can you just assure me that that's a bad assumption and that in fact, by deploying some of the technologies you've been talking about, you actually reduce the threat?

Respondent 1: Be careful. If done right, it can improve. If done wrong, not so much.

Respondent 2: What Respondent 1 said. There are a lot of people that have arguments about interoperability. One is that if you create greater interoperability, then the attack surface is giant, and yet at the same time, if you create interoperability, where data has known and standardized interfaces, and it can flow freely across the system, then that means that you've gained control and understanding of those interfaces, and the administration of cybersecurity is actually easier than the "What needs patching today?" kind of approach to things. So, it's certainly in the ground of every project that we look at, and in fact ENERGISE awardees have noticed that they actually must produce, post award, an interoperability plan and a cybersecurity plan, so we're kind of building it into the fabric of everything that we do. Ultimately, we're certainly on top of that kind of arrangement, but in terms of the risk-reward, that's where our research is taking us, that this interconnectedness is of more value than the risk surface it presents in cyber.

Question 13: First, a comment about the interconnected grid. I think that's a valid point. At some point you almost have to have an air gap in there if you really want a totally secure grid. But I think we need to keep in mind that regulation is kind of a bogie here for being part of the problem. In fact, much regulation actually occurs by legislatures or by Congress, so you can have some crafting of language that is impossible to operationalize and that is tossed over to the regulators to figure out. This happens time and time again.

The second thing is that regulators are typically in there for two years, or looking at a two-year time horizon. Their effective time period is about eight months. There is a huge amount of moral hazard in there in the things that are enacted, based on their presumption that they're going to get reelected or not. So, things get embedded in our system that are very inefficient from the outset, and that has nothing to do with the true capital R Regulator.

Also, we're doing something with PPAs in power generation such that I think we're embedding an inefficiency in the system with PPAs that are 20 years or longer with prices that are 25 cents, 35 cents, 40 cents. We've got a situation where we're embedding inefficient cost structures into our generation network that we're going to have to live with, and we're talking about 2040 now, 2045, when these things get rolled off, unless they're bought out previously. So we've created some inefficiencies at the get-go when we're talking about, "Well, we're going to have microgrids or…" that was my question about costs earlier. How does all this new technology actually work out with costs and the way we're embedding things right now? Thank you.

Moderator: Let that stand as a comment.

Question 14: First, just a clarification. There was a question earlier about whether capacity costs couldn't be allocated in the highest priced, highest stressed hours and induce more consumer response, and the clarification I want to offer is, yes, and we've been doing this in many regions for almost ten years. An interesting observation is, it induces enormous consumer response. In New England, here, we do this. We even see the municipalities, of all people (not generally viewed as the most profit maximizing entities), spend a great deal of resources to make sure they can manage and drop load on what they don't really know until the day it hits. That highlights the general point that I think one of the biggest impediments to end use demand response, and really distributed energy resources, is that end use customers throughout this country remain largely insulated, certainly at the residential level, from ever seeing the higher spot prices in the wholesale markets. To my view, as a guy who runs an ISO, that is the biggest impediment. I'm surprised it didn't come up earlier.

My second point to note, more specifically, is that much has been mentioned on the issue of dynamic line ratings and things that have all kind of cool acronyms that go with this, like FACTS, flexible A/C transmission systems, real-time dynamic line switching, and so forth. So, we have lots of people come in with all kinds of these cool technologies. There may be places where that's useful, but the reality is, when we run studies, they often just prove not cost effective yet. They're great technologies, they do what they're supposed to, but they're expensive, and the benefits, often, when you put them through the paces, are still pretty small. It may not be true everywhere, but it is really the Occam's Razor answer to why don't you see this stuff all over the place yet. It's not there yet in terms of value.

Respondent 1: Let me respond quickly to that. In New England, I think that's a very fair statement. We've had a couple teams that have done similar analyses for the New England region. It was a mistake to do it in this region right now.

Question 15: A more radical solution to changing the one in ten standard to some other standard is to stop applying a standard for the planning models, and I'd like to turn the mic over to someone from Texas to describe what's actually happening at ERCOT.

Comment: The Texas PUC spent a little over a year looking at the question and found that the one in ten standard was completely unreasonable. More importantly, nobody could explain the basis of it, other than, "It was good utility practice," or, "My grandfather did it," or, "Well, that's what my engineering professor said that it's supposed to be." So we've junked it. We've junked our target reserve margin, and, going forward, ERCOT will redo and publish the economically optimal reserve margin and the expected equilibrium reserve margin. And, in any event, we continue, right now, to have reserve margins in excess of 15%, which, if you take the Brattle study, is still borderline unreasonably high, but in the competitive space we don't regulate stupid [LAUGHTER]. I know that's a little harsh, because I don't think it is stupid, based on where prices have been in the first five months of this year, but all it takes is a little courage, and it works.

Moderator: That could go on a bumper sticker. "We don't regulate stupid." I think we have to leave it there, and let's thank our panelists.

Session Two.
Ancillary Service Markets: Is There a Link between Value and Price?

Market reforms have included recognition, not only of the value of ancillary services, but also that the market for such services can be quite competitive. How such services are compensated and how market participants can provide those services depends on the market rules. Since ancillary services markets were established, however, many things have changed, including the generation mix, emergence of demand response programs, and, of course, technology that can provide such services. These changes, as well as other circumstances, have led to concerns in some quarters that the compensation paid to ancillary service providers, in many cases, may not be adequately reflected in the prices being paid, and that perhaps some services were not being compensated at all. These concerns have led to debates within RTOs about how to address these issues and what rules, if any, require revision. What revisions, if any, are needed, and how should they be dealt with?

Moderator.

Good afternoon. I am very pleased to be moderating this panel. We heard an interesting panel this morning about how the world is changing and will continue to change. As that world changes, the market structure that we have in the bulk power system and the operational procedures in the bulk power system will inevitably have to change to address the increasing volatility that we see in markets--the increasing volatility of demand as well as resources within these markets, the ramp rates that we're seeing already in California and other places, and the need to address issues of the interaction between different kinds of critical infrastructure. Historically, how we have addressed these things is through what we've called ancillary services. And that's really the topic for this afternoon. Within this world that is going to be increasingly dynamic, increasingly uncertain, how do we make sure that the bulk power system continues to operate reliably and efficiently, and what's the role of ancillary services within that paradigm? In particular, we want to focus on the question of, as we begin to define and improve ancillary services, are we in fact going to be paying for the value that those services provide in a way that actually reflects the various kinds of services that are being provided? So, we have a very good panel with us this afternoon to talk about that. We'll hear from different perspectives in terms of different regions of the country as well as different perspectives in terms of the seats that people operate and the backgrounds that they come from.

Speaker 1.

Good afternoon, everyone. As always it is a real pleasure to be with you this afternoon. So, thanks to Bill and Ashley and everyone at HEPG for having me. I thought what I would do this afternoon in the few minutes that we have for introductory remarks is take you on a little bit of a tour through PJM's Ancillary Service Markets--the state that they are in, and more importantly, probably, for the purposes of this group, where we think they need to go.

But I figured, like any good panelist, that maybe the first thing I should do is answer the question that was posed on the agenda, "Is there a link between value and price?" My answer to that is that I think there needs to be, because in my humble opinion the very reason we operate these electricity markets at the wholesale level is to reinforce reliable grid operations. And if they are not doing that, if they are not providing the incentives for physical asset owners to act in a manner which reinforces grid reliability, and in the case of ancillary services, providing those services that the grid operator needs to maintain operational reliability, then the markets aren't working.

I have a couple of examples here of where things have kind of gone both ways in PJM's markets. PJM has operated markets for ancillary service products in one form or another since June 1st of 2000. That was when we put in the regulation market in PJM. We followed in 2002, with a market for synchronized reserves and then later on moved on with non-synchronized reserves and also a day-ahead product for what we typically refer to as supplemental reserve, 30-minute reserve that we clear on a day-ahead basis. And, just to state the obvious, the reason why we have these is to sort of unleash the power of competitive markets to ensure that these services are provided in quantities that are needed by the grid operator and also at the lowest reasonable cost for the consumer, while driving innovation, so that there is, again, the ability to provide these services by an array of providers that, again, lead to that lowest reasonable cost for the consumer.

So I'm going to start with an example, believe it or not, of where we actually may have gone overboard with respect to ensuring that we are valuing a service, to the point where we actually got too much of it. And that is the case of the PJM regulation market. So, like I said, PJM has been operating a regulation market since 2000, and right around the time of 2011, 2012, we had resources come to us that were alternative-type resources, batteries specifically, which were interested in seeing if they could provide the regulation service. And we agreed to do essentially a pilot project with a battery. We actually put a trailer in the parking lot of our headquarters in Valley Forge and learned a lot very quickly, both about PJM's regulation signals and also about how well a resource could follow these signals. One of the outcomes of that initial pilot was that we actually split our regulation signal into two different regulation signals. So, in PJM, regulation has always been defined as a five-minute product. It's resources that are online following an automated signal from PJM, the grid operator, and adjusting there in the case a battery output, we're charging automatically to follow, basically, a signal that was sent every two to four seconds. And what we realized with the battery is they could follow the signal faster than we could update it. And so we said, maybe we need a different signal for these types of resources given the benefit they could provide to the system. So that's what we did. So we split it out into a Reg A, we call it, which is the traditional typically slower-moving regulation signal that tends to stay higher a little longer and a Reg D, which is a dynamic signal which moves a lot faster and has a more of a tendency (and I'll get into that in a second) to center around zero. And things went well for a while. In 2012, FERC issued Order 755 requiring, basically, a performance-based compensation for regulation resources. We fit right in that, with the Reg D. We put in compensation for, not just the capacity of regulation, but also for actually moving to follow the signal. That's performance-type compensation. And, like I said, we saw increasing penetration of these resources over the years, eventually to the point where we got too many of these resources.

And we had two different problems. One of them was with the actual Regulation D, that dynamic signal itself that we were sending out, and then, secondly, we had a problem with how we were clearing the market and how much we were actually compensating these resources. And it turns out, in an effort, again, to stimulate the integration of these resources where we saw benefit, we were too generous in both cases.

One of the reasons why we were too generous in these cases is because these resources that provide the dynamic regulation are limited. And they're limited in the sense that they can only follow a raise signal or a lower signal for so long. So, if you think of a battery, it can only charge for so long before it has to stop, and it can only discharge so long before it has to stop.

So, unlike a traditional regulation resource, like a generator, that can follow a raise signal and just sit there at the raise position as long as you needed to, or vice versa in a lower direction, these Reg D resources are limited in that way. And, therefore, only a certain amount of those resources, of the total regulation assigned, were really beneficial. So, there's a tradeoff there.

When it gets to the actual issue we had with the regulation signal, what the chart shows is an actual instance we had where the ACE (Area Control Error) was high. So, we were over-generating and we needed resources to reduce in order to bring the ACE back down towards zero. And you can see that Reg A, that traditional slower-moving signal, was basically pegged at full load. The dynamic signal, the Reg D signal, because we had actually made accommodations in the way the signal was calculated to guarantee that dynamic resources would be centered back to zero, after they were in one position for so long, the Reg D signal in this actual instance is actually asking for a raise. It's bringing these units back to the center and fighting the ACE, instead of actually helping with system control. And so, to the extent that we got a significant penetration of these resources and this started to happen more often, because we had less of the Reg A and more of the Reg D, this actually caused operational issues.

And remember what I said about markets. These things are supposed to reinforce reliable grid operations, as opposed to causing operational issues because of the penetration of the resources you have. So that was the first problem we had--the signal.

The second problem we had was with the actual compensation. And from a compensation standpoint, we knew going in to the performance-based regulation construct that once we got to a certain level of penetration of Reg D resources, benefits would drop. And we had actually proposed to FERC that the price should reflect that. So, as the penetration of resources goes up, the price should essentially go down, to the point where it could actually go close to zero, or actually be at zero, if we got a penetration of resources that was in excess of the defined requirement. FERC did not let us do that back in 2012, and so, essentially, we said, "OK, but we're going to have to come back to you when this actually occurs."

So those are the two problems that we had and we are in the process of fixing both of them.

We made one big change so far. We have another one that's coming to fruition in the PJM stakeholder process. So, the first change was, we fixed the signals. Back in January, we essentially got rid of this forced neutrality where we would guarantee Reg D that they will be neutral over a certain period of time. It used to be 15 minutes. We went to a 30-minute period and said, "We'll make you neutral if we can do so without fighting the ACE," essentially. We called that "conditional neutrality." And now we sort of co-optimized these signals together, as opposed to having them previously be completely independent. This has caused issued with the Reg D resources we have on our system. And I am not going to sugarcoat that at all. Those resources were developed under some assumptions, I guess, related to the rules that were in place at the time. They have had to decrease the quantity of regulation that they can offer into PJM, because they are now being moved closer to their actual full raise and full lower points more often, and being held there sometimes when we can't, again, allow the neutrality to occur. But, again, it's prevented some of this counter-operational reaction of the signal and actually got us more of that full capability added to these resources than we were previously getting. So, we are working on tuning the signals and how they actually work together. And there are times, I think, when we're actually going to start carrying more regulation during certain times of the day, so we don't rely so much on those Reg D resources like we do today. But the point is that we're fixing the signal. We have made a change, and we're looking at refining that as we go forward.

The second thing we need to do, and this is what's been winding its way through our stakeholder process for about the last two years, is fix the compensation. And so, previously, we had this sort of curve in the clearing, where it was sort of a benefits factor. It did not make its way through two settlements, and that's why these Reg D resources can actually self-schedule all the way up to what we have sort of as a capped requirement, at this point. And they still get paid a non-zero price. I don't know of any other market, at least that we operate, where if somebody offers zero and self-schedules all the way up to the requirement, we still have a non-zero price. So this needs to change. I think the stakeholder community at large realizes it needs to change. We're going more towards what we call a different type of curve, a rate of technical substitution. Again, that's about as far as I'm going to go. But the idea is that as this penetration of these resources get higher and higher, eventually the price will come down and down and reflect the actual value of the resources to operations. We've been talking a lot about transitions, because of the resources that we already have on the system, resources that were, again, built under the old assumptions. And that's really sort of the hang up at this point. How do we get from point A to point B? And then, lastly, carrying that all the way through to settlements. The idea is that what we do in the clearing, as far as reflecting the value of resources to the system, needs to get through to what resources actually get paid. And that actually should reflect what the system needs for operational reliability.

So, this was sort of the big example, if you will, of when overvaluing can actually cause you problems in operations, as opposed to getting the resources that you really want and you really need, and we're sort of working our way through that.

Just to hit the other ancillary service markets very quickly, I'll go through the various categories very quickly. Again, day-ahead scheduling reserve is a 30-minute product. We only clear in the day-ahead market because it is not something that right now we are required to maintain in real-time operations. But the idea is to co-optimize it a day ahead, make sure we reserve that capability in day-ahead, have a non-zero price in day-ahead if we actually have to commit resources on that basis and to incentivize resources to actually provide that service. We have had some comments about some reforms necessary in day-ahead scheduling reserve. Our market monitor has made some recommendations in the *State of the Market Report*. I think they absolutely make sense to look into. In fact, frankly, I think maybe the best thing to do would be to actually institute a reserve product in real time that would marry up with the day-ahead product. And I think that would have benefits, not just for the day-ahead scheduling reserve market itself, but I think it would also help with respect to shortage pricing, in order to implement a trigger that might take effect sooner than our current trigger, which is 10-minutes reserves, which you get to too late to really make a big difference in really incentivizing resources to perform during shortage conditions. Plus, day-ahead scheduling reserve with respect to sync reserve and non-sync is sort of in the same category, I just don't have them on the slide. We have basically sort of a two-tiered approach to synchronized reserve. We have a certain amount of capability on the system that's online following dispatch, and if we have a contingency, you can just ramp up by virtue of the fact that it's following economic dispatch. If we don't have enough of that sort of naturally occurring synchronized reserve, then we assign what we call Tier 2, which are resources we actually have to request to operate uneconomically and therefore pay for. So we have to have a clearing price for Tier 2. And we assign that, again, to make up for any shortfall in sync reserves that Tier 1 is not able to provide. This has worked really well since 2002, since we put it in. But I think there are probably some improvements that could still be made. For example, we have a non-sync product as well, which is a non-synchronized, still 10-

minute, product. The clearing price for that is non-zero even fewer times than Tier 2 is, but when that non-sync price becomes non-zero, we also assign that price to Tier 1 as well, because Tier 1 in theory is actually a higher-quality synchronized reserve product, and it doesn't make sense to pay Tier 2 nothing when you're paying non-synchronized reserve a clearing price. Again, that has been a source of a recommendation from the standpoint of our market monitor, and what we do with Tier 1 in the long term and how it interacts with Tier 2 and non-synch is probably something we're going to need to look at as we go forward.

Last, but not least, I figured I'd touch base on something we don't have yet. We're asking ourselves some questions as to whether or not it makes sense to look at a load following type of ancillary service product in the future. We really have nothing right now between resources following dispatch by virtue of the fact that they're following dispatch instructions and therefore getting LMP payments either higher or lower, and regulation, which is that five-minute product. And one question I've been asking myself is, are we using regulation in a way that is actually hiding the need for a load following product? And what we're seeing, I think, in PJM (I'm sure it's happening other places as well), given the evolution of the supply resources we have on our system, is really a continued flattening of the supply curve, at least all the way out to the point where it actually looks like a hockey stick. And the question I've asked myself is, if the supply curve continues to flatten, will changes in LMP, as they get smaller and smaller, still provide enough incentive for resources to follow dispatch instructions?

And that's just a question I had, given the fact that, like I said, the resource mix is evolving. And I think it's worthwhile asking ourselves the question as to whether or not we design something that amounts to a load following product in order to incentivize that ability to follow dispatch, which, again, would then allow us to lean less on the regulation product, to provide what I think now becomes a load following service.

Question: When you're using regulation, obviously, it's to manage that variability on the system. Have you increasingly been using it as you've been adding more reserves as well, and that's why you have the challenge with whether you should maybe have a load following product as well? So you would continue to use Reg in all cases, no matter what the variability?

Speaker 1: The phenomenon I'm talking about has really been highlighted more recently because of that signal change that I mentioned in January. The accommodations we made for Reg D resources, where we forced that neutrality, and there was one I didn't even mention, where we actually expressly limited how far we move them to only 60 percent of their committed capabilities. So we weren't even trying to move them their full range. Once we stopped doing that, we saw that those dynamic Reg resources were actually being held Reg high or Reg low a lot longer than what they could really physically do, which is why they had to shrink the capability that they actually committed to the market. That's been happening with the traditional Reg signal for a long time. And, frankly, we just live with it. I think it's probably getting worse over time, and I think, looking into the future, given how the fuel mix is evolving, it's going to continue to get worse. And so, my suspicion, is that the way we use regulation is currently hiding, and it's only going to get worse at hiding, the fact that what we really maybe need is this product that would be load following. I hope that answers your question.

Question: In the last panel they talked about the increasing sophistication of algorithms and grid management devices. To what extent does your changing need for ancillary services also reflect the changing nature of your grid management?

Speaker 1: In terms of a changing need for ancillary services, I'm not sure that I've seen too much of an impact yet with respect to either intermittent resources or what we're seeing on the distribution side with micro grids. What we're seeing right now is, like I said, primarily driven by that evolving supply mix, but I think if we can do something that addresses what we're seeing today, I think it would also address variability that would be caused by other things as well.

Question: So, with your Reg D product, the offers are not time limited? You can't have a battery say, "Well, I can be at this place for an hour." Is that correct?

Speaker 1: Yeah. It would have to be even less than that. So, what they would want to say to us, I think, is, "You can only keep me there for 10 minutes," or something like that, and, no, there's no ability to do that.

Speaker 2.

Thank you, it's a pleasure to be here. You can see by the title of my slides, "Developing Essential Grid Reliability Services for a Low Carbon Grid," that I kind of broadened what I want to cover from just ancillary service to really all essential grid reliability needs. And ancillary service is clearly a sub element of that, but as California transitions to a low carbon grid, it's really changing what we need in the way of essential grid reliability services. And it's also highlighting that, as conventional resources get increasingly displaced with renewables and new technologies, these new technologies and renewables need to start being able to provide these grid reliability services. So my presentation will really kind of touch on that theme.

When we deal with policy makers in California, there is obviously not a good understanding of what these essential grid reliability services are. They're somewhat blissfully ignorant of what it takes to run a power grid. And so our role is often to be the technical advisor (we call ourselves the "physics police") on what it takes to make a power system work and how these very aggressive environmental policies can be achieved from a grid perspective.

It wouldn't be a California presentation without our [LAUGHTER] infamous duck curve. And, obviously, the duck curve has done a great job of highlighting some of the operational challenges with integrating large amounts of renewables, especially solar. But it doesn't cover all of those, and I would note that this duck curve really reflects what the system would look like under a 30 percent RPS. We now have a 50 percent RPS mandate by 2030, and our legislature is busy at work on a 100% RPS bill that would essentially have a 100% RPS by 2045, advance the 50% RPS to 2026, and have a 60% RPS by 2030. So, obviously, a very aggressive renewable policy, and the duck curve…we didn't update it here, but I can tell you we've done modeling of what a duck curve would look like under a 50% RPS, and you'll just have to trust me, it's huge. (It's a joke. [LAUGHTER] I'll have to work on my Trump impersonation, OK.) The belly of the duck actually goes negative under a 50% RPS, just to give you an idea of the challenge.

But of the two big operational issues that our curve highlights, first is the oversupply in the middle of the day when you have all that solar. If you can't find a home for it you're going to have to curtail large amounts of it. And then, of course, when that solar drops and your load increases in the peak, you have the neck of the duck. And that's the ramping challenge. But there are other challenges with bringing large amounts renewables on the system. Things like voltage regulation, frequency response capability, making sure that you have enough capability to respond to a major disturbance on the system. I'll touch on that as well.

The two themes I want to cover in my presentation are, how are we evolving our new market products to respond to this new resource mix? And then, how do we need to think differently about the types of resources that can provide these essential grid services?

So, one of the things we implemented, largely in response to the penetration of renewables, is something called the flexible ramping product. And this is really a successor to a flexible ramping constraint. And it kind of gets at the need for a load following product. Like PJM, we had regulation, we have operating reserves, but what this really does is it ensures, within the operating hour, that not only are all our market optimizations doing multi-interval optimization, we're making sure we can meet the ramp in the next interval, but we're also recognizing that there's some uncertainty around what that ramp will actually be, and ensuring in the optimization that we have enough head room both up and downward to meet that ramp, if it turns out to be higher than what was forecasted in the previous interval. So, the basic idea is it gives you some bandwidth capability so that if, when you get to the next binding interval in your market, the ramp is actually higher or lower than what the previous interval saw it as, you have enough headroom to meet it nonetheless. If you didn't have that, you run the risk that you would not be able to meet the ramp, and you would have to lean on your regulation, or lean on your ACE, and that was really what we were trying to avoid. It also provides a pricing component in the LMP now for this flexible ramping. It's not bid based. They don't provide bids for flexible ramping. But to the extent we're holding back our resource in the current interval, because we need it in the next interval for ramp, if it incurs an opportunity cost, that opportunity cost will set a price for that ramping requirement and that will be reflected in the LMPs. That's the basic idea behind it. It involves procuring, again, not just for the forecasted ramp, but for this cone of uncertainty, and the way we determine how much we buy to address that uncertainty is through the use of a demand curve, where we're essentially looking at, if we didn't buy that additional ramping capability, what is the probability, based on historical performance, that we would have a forecast error that would cause essentially a price spike, and that informs how much we're willing to pay to buy that additional ramping capability to mitigate that.

We also have a very, I think, well designed cost allocation for allocating the cost of this ramping capability. There's different cost allocation for the ramping capability you're procuring for your forecasted ramp. And then a different allocation for the ramping capability of procuring for uncertainty, but an allocation that is very much aligned with cost causation. We just don't peanut butter this to all load. We actually charge it to all the resources that are contributing to the ramp itself. Where, if they are actually helping the ramp, they're actually receiving this payment for helping the ramp. It's very new.

We just implemented this product last fall. The average payments on it for November, December, in terms of dollars per megawatt of load, are relatively low. It's about seven cents per megawatt hour, compared to 52 cents per megawatt hour of load for ancillary services. So there'll be some fine tuning with this in terms of how we set the requirements and the like. But I think it's a step in the right direction. In terms of the demand curve itself, this chart's just highlighting what that demand curve looks like. This is an average for November and December of last year for the 15-minute market. And this is for both the up and down flexible ramping requirement. And a way to think of it is, if you just take one hour, say hour eight, you can see that our total demand for ramping capabilities at about 1500 megawatts. Of that, we're willing to pay about up to $100 for the first 1200 megawatts, and then another $50 for the additional roughly 300 megawatts, and then the remaining megawatts, we're not willing to pay anything for. And those are set, again, by historical calculation of the probability of incurring a power balance constraint that would set the LMP at $1,000. So, if there were 10% probability of incurring that power balance constraint, the expected cost of that would be $100, and that's why you have a demand component at $100 for that amount.

Like PJM, we implemented some refinement of the regulation market. We have a regulation energy management which really, like Speaker 1 described, allows us to integrate new resources into the regulation market, particularly battery resources. Our regulation product is 60-minute product, with regulation energy management. A battery that can only provide 10 minutes of energy can be effectively managed within the 60-minute process through our market. So it enables them to participate. We implemented pay for performance regulation in 2013. Like PJM, there's a two-part payment. There's capacity payment, and then we have a mileage payment which really is to try to get at getting faster response regulation into the market.

I can tell you this design has not worked as well as we would have hoped. The mileage payment that we're seeing is practically zero. What we're seeing instead is resources prevailing in the regulation market that have load capacity bids and large mileage capability. They're typically the large hydro resources. So, they'll put in a penny for their mileage bid. So the premium that we're getting for mileage and accuracy right now is not coming through. So beginning next year we're going to do a major review of the design of that market, and we'll look to make refinements to it to really better value fast response and accuracy, where the market right now is not valuing that.

On the regulation front itself, though, what we saw last year, in 2016, the total cost of ancillary services doubled from where they were in prior years. And that's because, with the increased amount of renewables, we're buying a lot more regulation, especially during the spring months when the integration is especially challenging. In the first two quarters of last year our regulation prices spiked up, and essentially more than doubled what they were the same period last year. So we're buying a lot more regulation, both up and down, and the prices are really increasing significantly. So in terms of valuing the regulation, we're seeing a big increase there.

In terms of new market products, as well, I mentioned the frequency response challenge. I like this graph because it kind of highlights the timeframe for addressing a frequency disturbance, where the black line is essentially your frequency level. So, you had a major disturbance, you had a drop in frequency, and the chart gives you the timeframe of the different controls you have to mitigate that. So, we talked about Speaker 4 and his presentation in the morning. We talked about the loss of system inertia. Less inertia means that the speed at which you have that frequency drop is going to be faster. So inertia essentially buys you some time in terms of the frequency drop, so that your primary control can kick in to arrest the frequency. When you have a lot of renewables on the system, you're losing that spinning mass, so you're losing that system inertia. You're also losing your primary frequency response, because conventional generators with governors were typically relied on to provide that primary frequency response in the one to 10 second timeframe. With more and more of those resources being offline, and renewables really not currently configured to provide that, we really have a concern here that we don't have that fast response, within the first 10 seconds, to address frequency. The secondary control you have through your regulation, and then your tertiary controls your spinning reserve that you can bring up, so we still have those. But we're losing that primary and inertia response that we really need to make sure we can manage.

As I mentioned, California has very ambitious renewable policies, clean energy policies, and we really are in the forefront of moving to a low carbon grid. And the next step in that, in my view, is we need to be looking at renewables as a holistic grid resource instead of just an energy resource. And so, when you look at the various services that we rely on conventional power plants for--load following regulation, operating reserve, frequency response, voltage regulation, as well as local services--if we're truly going to wean ourselves off gas-fired resources in California, then renewables storage demand response has to step into that space and provide those services.

We did an interesting pilot with a 300-megawatt solar PV plant last year, and the purpose of this was really to test the extent to which a large scale solar PV facility could provide the essential grid services. So, we did a series of tests where we put this plant through its paces on its ability to provide ramping energy, to provide voltage support, and to provide both low and high frequency response. And the results were quite outstanding. Just to give you quickly an example of that, in terms of active power control, one of the problems we have with renewables is their inverter base, especially the solar PV. It's like having a Tesla-esque ludicrous mode. If you ask it to move it will move so fast, the operators aren't ready for that. They're used to that old Chevy, whatever, Chevy Impala, that took a while to ramp up. So the system's a lot less forgiving when you're dispatching these renewable technologies. They move very quickly, and you can move massive amounts of megawatts in seconds. So one of the things we're looking at is, can we slow them down? Can we impose a ramp rate on a solar plant to make it move more in a sane speed when we need it? And what this test demonstrated is, yeah, you can do that. You can impose a ramp rate on a solar PV plant and get it to move at a much slower pace and really follow a dispatch signal.

Regulation. We had the solar PV plant provide regulation service. It did phenomenal. I would note that this was a blue-sky day, not a cloudy day. The results will vary. [LAUGHTER] But when we stacked up the performance of the solar relative to conventional resources and regulation accuracy, it far exceeded the performance of gas resources, particularly, as well as hydro.

Voltage control. Again, in the interest of time I won't go through all this, but you can set a voltage set point for this solar plant, and it will follow it with great accuracy and can really move the voltage point of interconnection quite effectively. And, importantly, this simulation was to approximate what the solar PV could do at night. So, you think of a solar PV plant as useless at night. Typically they are, because they disconnect from the grid, but if you kept them connected at the grid, you could leverage the inverter to provide voltage regulation even during the evening hours.

Frequency response. We put it through its paces on simulated high frequency responses, and we really got incredibly fast response. I have charts, not in this presentation, but almost inertial-like responses to frequency disturbances that were quite impressive.

So the bottom line with this is we're trying to educate the policy makers in California that this is the next stage of maturity for renewables, and getting them to provide these grid services is really going to require thinking differently about them. Right now, they're only valued for their renewable energy credits. We're going to need a regulatory framework and a commercial market framework that values these renewables for these other grid services. And we will continue to look at this in terms of our market and in terms of what we need to do to remove barriers for these resources to provide those services.

Question: You talked about solar up and down in your chart, but then your performance slides that followed seemed to focus on up. So, was solar able to manage your set points on the down as well, and were your performance metrics related to the down as well?

Speaker 2: You're talking about regulation?

Questoner: Yes.

Speaker 2: It can provide regulation up and down. It could respond to a low frequency disturbance, a high frequency, so, symmetrically, it can do it. Now, providing upward capability means you have to hold the resource back. So there has to be a recognition that there's an opportunity cost of holding it back. You’re not getting those renewable energy credits produced. But, technically, it can do it.

Questoner: And same with down?

Speaker 2: Yes.

Queston: Providing the sun is out.

Speaker 2: All providing the sun is out, though I would note this gets to these hybrid projects where you combine solar with storage. We’re seeing more of that in California, and a hybrid project like that even on a cloudy day could still provide that kind of performance.

Question: On the flexible ramping product, you said that the costs of it were allocated to the resources that are causing the ramp, and I wanted just a little more granularity about that. Are those charges tagged to generators, rather than to load? And to the degree that they are, how do you deal with the fact that so much of this is behind the meter solar that’s driving the ramp?

Speaker 2: I have to parse this a little bit. As I mentioned, we have two different cost allocations: one for the ramping product we’re procuring to meet the forecasted ramp, and then a separate cost allocation for the additional ramping capability we’re procuring for uncertainty. So with respect to the forecasted ramp, the prices that come out of the flexible ramping product get paid and charged to all resources in the market, whether it’s load, supply or the inter-ties. So, if in that particular interval you are moving in a direction that’s actually helping the ramp, then you’re getting a payment, based on whatever the price for that flexible ramping is. If you’re moving in a direction that’s exacerbating the ramp, then you’re getting charged for that, for the fact that you are contributing to the need for that flexible ramping product. So that’s how it works for forecasted.

For uncertainty, it’s a little more challenging, because the uncertainty procurement is kind of an insurance policy. It’s really twofold. One, against mitigating a power balance constraint violation and two, making sure that ultimately for the resources, the prices are reflecting the service that these ramping resources are providing. So that gets allocated through a two-tier process where you have three buckets. You have load, you have supply resources, and you have inter-ties, and it’s pro rata based on their historical contribution to the forecast error. So there’s a first-tier allocation to those three buckets based on their aggregated historical contribution to forecast error. And so once they get their allocation it gets distributed to all the resources within that bucket based on their specific contribution to the forecast error. So, it’s a little different and it’s more historical looking, based on historically what has been the relative contribution to forecast error and the costs get allocated that way. So, I hope that helps.

Question: I have a two-part question. First of all, you mentioned that the study was related to the 300-megawatt solar farm. What was the range of the size of the solar farm that would be applicable for that type of control? And, number two, with a number of the eastern U.S. states looking at the grass of renewable targets… I mean, that, for me, is a real selling point for large-scale renewables, over and above the need to produce a step change. Do you have any other comments, from a policy perspective, about large-scale renewables for satisfying the standards for the region?

Speaker 2: In terms of the capabilities, it’s more of a function of the control systems that the plant put in place, and it’s technology. So I don’t think there’s a size threshold, if the 20-megawatt solar plant had the state of the arts sophisticated control system and state of the art inverter, they should be able to supply all the services. The challenge more is that not all of them do, because there’s additional cost to having that state of the art capability, and in a market that’s just saying, “I just want your renewable energy credit,” there’s not a big commercial incentive for parties to pay to get that. So that's part of the education that we have to do.

In terms of the question of whether this increases the value proposition for large scale solar, maybe so, from the standpoint that these resources are things that the grid operator has access to. We don't have access to behind the meter solar in terms of that kind of capability. That's not to say they couldn't provide it. But, ultimately, we work with the transmission connected resources. So at least from that standpoint, maybe that would be a more compelling proposition.

Question: This is a quick cost allocation question on regulation. You mentioned that it seemed like your regulation quantity and prices have increased recently. How do you allocate the cost for regulation? Does it go to loads? Does it got to the resources? Or how do you do that?

Speaker 2: It goes to load.

Question: On the flexible ramping product, you indicated that at least part of the cost is allocated based on the contribution to the forecast error?

Speaker 2: Yes.

Questioner: And that would be to resources that are causing that? So, for example, wind, depending, I suppose, on where it is, if it's a large contributor, would pay in a larger share of the product--even if it was otherwise renewable or clean in California?

Speaker 2: Yep. So, renewables are subject to this cost allocation as well. So, they have an incentive to improve their forecast capability.

Questioner: Do they have to bid or meet a schedule in their bids in the market, or are they just price takers?

Speaker 2: It really varies, depending on the power purchase agreement they have. Most of the new power purchase agreements now have economic bidding requirements. So, for those resources, they are required. Some of the older contracts don't. But I would say that when we curtail renewables (and we do a lot), it's almost always based on economic bids. They're providing economic bids. So, very seldom we have to go to non-economic curtailment.

Question: Are you allowing solar resources to provide frequency rate services?

Speaker 2: Yeah. There's nothing in our market that would preclude a renewable resource from providing regulation, but we're not seeing it now.

Speaker 3.

Good afternoon everyone. Thank you again for the invitation to come. What I want to do is start to generate some discussion. Certainly, I think there is a link between value and prices for ancillary services, but I think this is the group that is probably going to really answer that question.

I spend a lot of time in New York thinking about REV and the panel earlier today, and the question I always have is, how do we get from here to there? So, everybody talks about this 2030, 2040, maybe beyond, future and it doesn't seem that far away. It seems like that's a pretty broad timeframe, but it doesn't seem like it's that far away, and I don't really know how we transition. That's not clear in my head. I don't know how that works. But one of the things that I am struck by is that 10 years ago I was working at a consulting firm, and we did the *Annual Energy Outlook* for the EIA, and we weren't talking about shale gas at all. There's no forecast that took into account what would happen in natural gas. So, sitting here, having some of these conversations, I'm actually a little bit relieved that we're at least talking about it and recognizing that this is something that's going to be pretty fundamental, potentially, and we're actually starting to think about it. So, that's good.

When I started to think about this topic, I really kind of went back to the tech conference in 2013 on capacity markets. And at that point we were starting to recognize that, "Hey, maybe we need certain kinds of resources. Maybe the capacity markets aren't working, or those are the places where we should be trying to incent these kinds of resources." And everybody said, "No, no, no, that's not the place." Even at the time that PJM and ISO New England were starting to do some of the capacity performance, performance incentives, pay for performance mechanisms, but overall everybody said, "Don't focus on the capacity markets, its energy and ancillary services." So then we got into this price formation effort, and we're still sort of in the middle of that, but I think that that's definitely been a fantastic focus, and something that hopefully will be really helpful.

Now we're starting to talk about state policies and how all of that can actually fit together, what the impact on capacity and energy markets is going to be, given what states are doing. And in the midst of all of that, we were talking about gas-electric coordination. And now here we are talking about ancillary services. And I think that they're all combined, and I don't think that we have a good framework yet for how all of that combines together, and what it is that we're looking to value and what we would be pricing. So, I hope what I'm going to do is try to bring some of that together, and, as I said, generate some discussion.

I think we've been sort of talking about this all day, and I think that's what we're here recognizing, is that the grid of the future is definitely going to look very different from what we're seeing, although maybe not so different for California-- they're already seeing all of this. But the expectation certainly is that these technologies that we're now recognizing are something we have to figure out how to better integrate, are things that are just going to be cost competitive and things that if we don't kind of figure out how to integrate now we'll definitely be forced to figure it out later. And that's typically the context when we're talking about a lot of these ancillary services. But I think the context is actually much broader.

And I'll talk a little bit about these significant changes that are facing the electricity markets, which I think everyone is pretty well aware of, but obviously we're in an environment where we have record low wholesale energy prices. We are in an environment where we're seeing little to no load growth--a lot of that due to the fact that we're seeing some of these behind the meter and energy efficiency efforts. And then we have this big effort to accommodate state policy. And when we're talking about accommodating state policy, I think we're really talking about two things.

So, one, it's the recognition that we're moving to the future, where we're going to have resources that have little or no marginal costs. So, what does that mean for an energy price? What does that mean, if we think about ancillary services in terms of their opportunity costs for not providing energy? How do we actually think about these resources that we're accommodating? And then, obviously, thinking about uneconomic retention and what that means when we're keeping certain units on, what that means for both the energy markets and the capacity markets, especially when the expectation, I think, is of this future where we have very low energy prices, where we have a lot of renewables. I think some of the traditional resources that we think about as being needed to make sure that the grid remains stable and a lot of these essential services that provide that stability are around… Maybe the capacity market is the place to rely on given that the energy prices are going to be low. Well, what do you do when the capacity markets are also distorted? I guess maybe we look at ancillary services. I don't know. Maybe that's part of what we're talking about today.

So, when we talk about resource adequacy…at that 2013 tech conference, this paper actually got quite a bit of discussion, and the idea was, the power system in the future is one in which the traditional approach to assessing resource adequacy and isolation from system security will no longer be a least-cost approach. And this paper was particularly looking at renewable integration and saying, how can we think about resource adequacy no longer in the context of just having enough capacity, but in the context of asking whether you have the kind of system that can enable the kind of integration that's needed and keep the grid stable? And I think this paper started to go there, but, to me, it's not quite the full picture yet. And I think that NERC is actually starting to get there. They've been looking at what the essential reliability services are. And I think that no longer talking about these as "ancillary," but talking about these as "essential" is really getting there. They started to think about these essential services, but they also were starting to think about what you do when you have a lot of natural gas on the electric system--when you have most of the resources being generated by natural gas? And how do you think about planning? How do you think about reliability? How do you think about these things in a context that's very different than the kinds of reliability that traditional resources have provided? So I think NERC is certainly starting to get there. NERC actually has provided (both in this context and in the gas context as well) some tools to the reliability coordinators to say, here's how you can start to think about measuring these things. Here's how you can start to think about what kind of ramping you might need. Here's how you can think about what kind of frequency support you might need. And, really, what they're suggesting in this context is to say, given the system that you have today, given what you expect for renewables, what is the gap and how can you plan for that? And they don't really go here, but the next question is, how can you start pricing some of that? And it sounds like some of what California's doing is actually what NERC has started to suggest here.

But I think that still isn't the full story. Perhaps we can look at what NERC is suggesting in saying, let's look at the net demand. Given all of these resources that we expect, whether it's renewables, or whether it's all this behind the meter things, or whether it's this integrative, interactive demand, let's think about what the end net demand will be and what kind of essential reliability services will you need. But they also say, what are the gas system contingencies that you're going to need to meet, to recognize, in order to make sure that the grid is stable and that the resources that you're relying on to provide a lot of this resource adequacy are actually capable of doing that?

And I always bring up this study wherever I am, because it was a really interesting study. When we were initially talking about a gas-electric coordination, the Eastern Interconnect Planning Collaborative did a pretty extensive study to look at what the expectation is for the amount of gas that's going to be coming on, the amount of gas that's going to be dispatched on a daily basis. What's the pipeline system look like? Where are the congestion points? One of the important pieces of this analysis was really looking at some of the gas system contingencies that could impact the electric system, and vice versa. And they looked at some of the major pipelines that go into each of these balancing authority regions and said, "What if we lost a major compression station? What if had a line break? What if we lost access to storage on the gas system? How quickly would it have an impact on the electric system?" And there are some contingencies that you just don't have any time to respond to at all. There are some that you have less than 15 minutes to respond. There are some that you have less than an hour. And there are some that you have many, many hours, so the system would have adequate time to re-dispatch. But, especially when we think about ancillary services, essential reliability services--ramping, flexibility, fast responding resources--a lot of times, until we get to the world where we have a lot of storage, talking about gas and recognizing, as the earlier panel said, that this is a much more integrated industry—it's gas, it's electric, it's water… It's all of these things, which I think we're thinking about in isolation, but which we really need to start thinking about more holistically.

So they had various scenarios, and the one I showed you was just the reference scenario. So, for example, they looked at a day in 2018, and asked, what would it look like if we had these contingencies? They were looking at winter and summer in 2018, and winter and summer in 2023 under a high gas scenario and a low gas scenario. And they looked at all of these contingencies and said, what would happen? How much would be undeliverable, given what we expect the system to dispatch on gas? And on the reference scenario there were some instances where there would be concerns on the electric system as a result of things that happened on the gas system, but there are certainly other scenarios that that was even more the case. And I'll add that the study assumed a number of pipelines in the Northeast that are not here. Because we've had pipelines not being able to be sited in some of these regions in the Northeast. So, I imagine some of this could actually be much more challenging.

And then what I wanted to do here is kind of put this in a little bit of context in New York. So, this slide is something that Potomac Economics, the Market Monitor for New York ISO, put together. This is January and February of 2014. So, this was the polar vortex period, and they were looking at Eastern New York in particular, and at what was being held as 10 minute reserves in Eastern New York. So you can kind of see the line that shows what the reserve requirement is, and you can see where the prices are, but you can also see how many of those reserves are being held on gas, and these are gas-only units. And the reason this matters in eastern New York in particular, is these are days that had hourly OFOs (Operational Flow Orders). And on the interstate pipeline system, it's pretty rare to see an hourly OFO. On the LDC (local distribution companies) system, which is what a lot of Eastern New York is on, it's not that uncommon. When it's really cold, they don't expect that gas generators are going to have access to the gas. They have an hourly OFO. It's very restrictive. And gas units really don't expect to be able to get gas. And even if they did, I don't know that, collectively, all of them that are being held as 10 minute reserves could very easily take the gas at one moment. So, the market monitor identified what would have been deliverable for those 10 minute reserves, which is shown on this slide. So, for the reserves that were gas only, the monitor looked at the unused transfer limit on Central-East, which is the major interface dividing West and East New York, and also looked at reserves that run on hydro and oil.

And he has concerns that in New York, units are being held in reserve that may not actually be deliverable, number one. And he recognizes that the operators are calling SREs (Supplemental Resource Evaluations) in these instances, because they don't believe it either. That's basically what he said in the report. And he's made some suggestions, saying that in order to accurately reflect where some of these limitations are, that maybe we should have some kind of different tradeoff between what the price is for the SRE and what the 10-minute reserve price is. And he's starting to make some suggestions and go there, but we haven't gotten there yet.

All of that to say, I think now we're looking at these essential services, and I say, "Are they the new missing money?" I know everybody in this room is going to tell me no, because I'm using that term inappropriately. But when I think about it in terms of resource adequacy, and I think about it in terms of system security, and just thinking about how we've used the capacity markets in the past, are we now looking at not pricing these essential services accurately either? And then, I'm thinking about resource adequacy in terms of system security and saying, just because we price inertia or just because we price ramp, it doesn't mean that we're actually considering some of these contingencies on the gas system. So, what does it really mean to be a flexible unit? What does it really mean to be a fast ramping unit, if you're drawing on a system for which you haven't actually either planned for contingencies and you certainly haven't priced contingencies in the electric market?

Moderator: OK. Clarifying questions? Just while people are putting their cards up, define OFO and SRE for us.

Speaker 3: Sorry. Operational Flow Order. So, with the pipeline system, most of the time you can take gas fairly easily. There's not a lot of restrictions, but on a peak day, where you have demand from residential, commercial and industrial customers who are basically using everything on that pipeline, they put in place some of these restrictions, and one of the restrictions can be that, instead of taking a certain amount of gas in the morning and taking a different amount later in the day, you have to take the same amount all day and every hour, and a peaker certainly can't do that.

And SRE is Supplemental Resource Evaluation. That's an out of market unit that the operator brings on.

Speaker 4.

Thank you, and before I get started I first wanted to thank the rest of the panel, because Speaker 1 started off by explaining the most complex market that we have, and I think it's the same in all the markets, and that's the regulation markets. So, thank you, Speaker 1. Speaker 2, you addressed the high-tech aspect of looking at the way the system can be operated, and I think California is on the bleeding edge on that one. You have some imminent needs. Speaker 3 covered the low tech needs, and I agree with her. People aren't focusing on those, and they probably should. My focus is more on the basic building blocks.

We started restructuring in New England in the late 1990's, and I would argue we're still implementing it. Some members of the prior panel said that we have to be willing to make mistakes. We did. We implemented things that didn't work too well. We tried energy markets that weren't locational. Then we implemented ones that were. Then we're implementing day-ahead markets that I'll get to later, and still have some additional work to be done. The bottom line is, I think this work will always continue, and I think that addressing these changes, some of which come unexpectedly—certainly, the low gas prices from the increase shale gas. But I think some of these other changes are going to happen more gradually than maybe some of us are fearing, because of just the commercial cost of doing these things. Certainly, we're being challenged in New England. We have a bunch of things that are happening at a state level, for things that aren't necessarily even tied to the cost of electricity--carbon reductions, for example. But I think even those will benefit from some improvements to the basic building blocks.

When we're talking about ancillary services, it really starts at the system planning level. That's years ahead to months ahead, depending on what you're looking at. It goes all the way to the day-ahead scheduling process, with the day-ahead market, real-time market and then regulation, or frequency control. Inertial primary frequency response, are ancillary services that currently are simply required resources that are capable of providing them as a condition of interconnection. So you can interconnect to the system, and if you can do that, you will do that. There's no particular payment or distinction in any of the other market payments for providing that. Voltage support and control is also a requirement of interconnection. It does have a payment. It's a very imprecise payment. The only thing that's precise in the payment is probably the payment of lost opportunity costs when the real power output is decreased to provide reactive power. But the capital cost element of that is simply a proxy for the cost of the unit that doesn't exist. And the initial rates were really established through FERC settlement efforts. So, they were disputed in their initial rate and we ended up with something that everybody could agree to. I thought that might provide a little bit of insight as to how things really turn out in the real world, as opposed to perhaps how some of them are planned when there is a lot of time spent developing a rate and trying to support it.

Moving on to a chart that shows a breakdown of the market revenues, in this case for 2015, that tells a couple of stories. First, the ancillary services that are explicitly ancillary services (excluding the energy market participation) are really only about three percent of the total market payments. Pretty small. In 2016, they went up a little bit, but not in a way that changed the overall ratio. Also, obviously, the energy market is the most substantial market. And I also wanted to emphasize what Speaker 3 was alluding to, which is that, with the surplus in gas, notwithstanding some periods where transportation may be limited, the energy margins are shrinking. So, a lot of the conventional resources that the system operator is relying on to help control the system and balance things like our ramp, when they're trying to deal with solar in the forecast error and determining what solar output to expect, what's going to happen behind the meter, aren't getting a lot of revenues from the energy market. The capacity market clears three years ahead. So, whatever the price was agreed to three years ago, you're going to live with that combination, the current energy market, and whatever ancillary services are available. The bottom line, I think, for a lot of conventional resources, is that's going to be a pretty tight time. And some of the things that may need to suffer on that may be maintenance.

Moving on to the day-ahead market, our day-ahead market does a great job on locational prices for the amount of cleared demand. Cleared demand doesn't always reflect the amount of demand that we'll see the next day, and, in fact, I provided on this slide the prices that were developed in the day-ahead solution for May 19th. That was our unexpected heatwave, where we got very warm weather in New England during a time when a lot of infrastructure was out on maintenance. This is typically our low load period. And on that day, there was substantial amount of under-clearing of load demand in the energy market. And so, the amount of supply cleared in the energy market was a lot lower than the actual demand. It panned out well for those resources on that day, because real-time prices were even higher. But one of the shortfalls in that market is that there's not co-optimization of energy and reserve. There's a sequence of scheduling steps that occur, starting with a unit commitment step that just attempts to meet cleared demand on an energy balanced perspective, basically. Then there's a security assessment of whether or not that commitment produces enough operating reserve to keep the system secure under that unit commitment. And then you finally get, after you develop the units that will be put online to provide the energy from a synchronized state, you get an economic dispatch.

There's no operating reserve compensation. So, our reserve portfolio is largely a pumped storage facility. We do have approximately 200 megawatts of other hydro, but we have about 1200 megawatts of pumped storage hydro, and that's a fast start resource, and we are actually concerned that, in the day-ahead market, because there isn't an explicit compensation of operating reserve, but there's a value to meeting the security aspect of that solution, that we may actually be facing some lost energy market opportunities. It would otherwise be picked up as lost energy market opportunities in the way the solution is developed, so there's some shortfalls there. Clearly, there's a need for improvement.

The good part is that improvement is currently planned. But I think this also will provide some insight on the road ahead. This is a complicated project. It's in the market project plan for a target of 2021. So, we have work to do in the day ahead market. We're really not valuing operating reserve there, and to the extent we're valuing ramp, it's on an hourly basis. We have a forward reserve market that was developed really to incentivize quick start resources when New England didn't have as many of those. It's at least some form of advanced operating reserve purchase. It has quite a few shortfalls. I'm not going through all of those, but there were a couple of things I did want to emphasize here. Under the category of "opportunities for improvement," there's one that I think would apply generally to all ancillary services. And, here, the requirement doesn't match up as well with the eligible supply. The requirement is only for the 10-minute non-spin and the 30-minute operating reserve requirements, not the 10-minute spin. Yet spinning reserve is eligible supply in this market. And so, there's a mismatch between the eligible supply and the actual demand in the market. There are other problems as well. For example, the same amount of compensation is paid to a resource (absent being penalized for non-performance) that just may sit there and never be activated if there is a contingency response as is paid to a resource like ours that is very frequently activated if there is a contingency response. And there are areas like that that would benefit, in any new look at ancillary service, in terms of trying to better incentivize performance, because the ones that are actually providing the value, they're providing the protection for the system.

That brings us to the real-time energy market. I've separated energy payments, which I called here "ramp activation," from operating reserve payments. I want to give credit to ISO New England. They have been pursuing a number of changes that were implemented, many of them, in March of this year. And among them are fast start pricing, hour ahead bidding and five-minute settlement.

Before fast start pricing, we'd turn on a unit because there would be a significant need on the system, and it would actually push LMPs down. So, this change in the model actually helps the price better reflect what's needed on the system and reflects the link between service and value.

Hour-ahead bidding allows updates. Previously, we were limited to day-ahead bidding, which doesn't work too well when you have a limited energy resource.

And five-minute settlement finally takes away the arbitrary distinction between hours. Before, there were integrated hourly LMPs. Now there are five-minute LMPs, which aligns much better with the iteration of the real-time dispatch model.

And if the unit dispatch system model changes its solution every five minutes and sends out new signals, what really matters is what you can do in five minutes or longer, if sustained ramp is needed. What you can do in a timeframe shorter than that really isn't valued. So, in terms of new technologies, that's something that they need to keep the mind. I think, often, the discussions revolve around questions like, "How can my faster response be valued?" I think part of the discussion needs to look at what the system can use. And in this case, the dispatch model can't use anything quicker than a five minute interval.

The final thing I wanted to point out here has to do with opportunities for improvement. One is full integration of price-responsive demand. DR is really not new at all to New England. We've had it for quite a few years now. The shortfall has been that it's only been activated as part of emergency actions, when they get to a shortage period. And starting in June 2018, it's going to be hard integrated into the dispatch. So, if they sell capacity just like a generator, you can have real-time offers and day-ahead offers, and they can schedule you as needed to meet system needs. That's a tremendous improvement. It's unclear what impact that will have on the demand response market. I guess we'll find out when that gets implemented.

When it comes to real-time capability (really a shorthand for real time operating reserve), right now, there are two things that the system operator needs in real time and not just in the five-minute interval, but in planning for the future intervals, and that's, "What am I going to have for operating reserve to meet a contingency?" and the other is, "What am I going to have to meet my future interval ramp needs?" And, unfortunately, right now, the market reflects what's needed to just get that operating reserve. The problem is, that results in a lot of hours of surplus, because you need ramp available for future hours, and the resources that need to provide that aren't necessarily that fast. So, that doesn't work too well for prices in those hours. And real-time operating reserve prices and real-time ramp are priced at zero many hours a year. It's really episodic. In 2016, 40 percent of the real-time operating reserve payments to resources came on one day, August 11th, when the prices in New England went very high because of scarcity. An opportunity for improvement here is to start incorporating some value for what's needed across multiple hours of ramp. And New England does have a project here as well. The discussion with the stakeholders will start later this year. And this is the reason why that other project has been moved out to 2021. And I'll get to the whys of that on the last chart, because I think it applies generally not to this specific product.

In terms of real-time ramp capability, the 10-minute operating reserve is the highest quality product. So, if a resource can ramp faster than 10 minutes, that's interesting, but not valued.

I'm not going to go through the regulation market. Speaker 1 did a great job, and I would do it an injustice to try to repeat that. Simply to say, it's a very sophisticated market for a very small purchase. In New England it's 150 megawatts. That's 10 times smaller than the operating reserve market and 100 times smaller than the energy market. So, it will provide opportunity for some, but, ironically, when it comes to the changes that were made after Order 755 to address (at least in New England) flywheels, as soon as those changes were implemented, or shortly before, the flywheels left and went to New York. So, sometimes we really need to think about the amount of effort we put into some of these things, and what's needed, versus what might sound interesting or be valuable to just a few.

Turning to practical realities, I should explain why some of these things have us looking out to 2021. Why does it take so long to do these things? There is a lot of staff at ISOs, but they have a lot of different jobs. There's only a limited number of folks inside of each of those organizations that has the expertise to work on these more complicated projects. When you start getting into multiple systems, particularly the dispatch and pricing software and the settlement systems, you rely on certain individuals and the staff or certain groups of individuals who can't all be doing multiple big projects at the same time.

But that's not the only limitation. We also have a stakeholder process that we have to go through, at least in New England. There is a four-month minimum to that, unless FERC directs us to do something shorter, in which case we have no choice. But sometimes it can be longer, and it likely will be for this multi-hour ramp product. It will take longer to get through what the need is, what's proposed to solve it, and whether or not there are alternative designs proposed.

Finally, we get to FERC. They have their own review and approval process, and then there's always the opportunity for rehearing, and all of the wonderful process to follow that. And there can also be directives that can change priorities. I mentioned Order 755, which had some good regulation market improvements, if that's your real focus, but it's a small market. That Order deferred a project that I have been waiting for since 2006 on our pump storage facility, because it wasn't until this past March that we had the ability to have our real-time dispatch of our pumping incorporated into the real-time dispatch on a price basis. So, there are side effects when we try to change priorities on things, too, and I think those need to be considered.

Finally, RTO implementation also requires outside vendors. The area there with the greatest bottleneck is probably the dispatch and pricing software company, Alstom. Everybody goes to them, and they had some of their own organizational issues this past year that effected some of the timelines that pushed out that March one, which was supposed to happen in late 2016. Bottom line, complex changes are going to take a lot of time, sometimes years, and we're not done with the work completing the current design. So I think that, with respect to all of the discussions that we had earlier, changes will need to be made to accommodate them. But I think we're going to have to look at them in a timeline that's probably more consistent with what's achievable. Thank you.

General Discussion.

Question 1: I wanted to link this morning's session to this afternoon's session. In the morning, we talked about electronic converters as being kind of modern technology. Well they're not. They're 40 years old. But linking that to this afternoon, a number of the technologies ,form the UPFC (unified power flow controller) tied to HPDC (high performance parallel and distributed computing) and others, they not only provide a real power capability, they also provide a reactive power capability. And with the new modern IGBT (insulated gate bipolar transitor) based converters, you can do it independently with four quadrant control. Those types of investments struggle when there's a reliability or another project for capacity, because there's no benefit given to their ancillary benefits. So, for Cal ISO and PJM, how do you think about related transmission technologies and their end benefits to the market?

Respondent 1: Probably I'm on a dangerous ground here. From our planning standpoint, we do get transmission technologies to provide reactive support. We install a lot of SVCs (static VAR compensators), synchronous condensers in our grid, in lieu of relying on generators to provide that capability. So, I think we have a good model and planning framework for enabling that. I'm not sure, beyond that, what more we could do. I think we have a good framework for it.

Respondent 2: We're very similar. In fact, as a result of our planning process a bunch of years ago, we installed what was at the time one of the largest SVCs in the world, down in the Northern Virginia area, through the planning process.

But I thought you were talking more about sort of from a market standpoint idea of incentivizing that kind of thing, and I don't know that I have a good answer for you, because, for example, from a purely reactive standpoint, it's still a cost-based service, at least in PJM. I think that's probably the case elsewhere as well. A provider of reactive service can file a cost-based rate with FERC and then recover that. I've always had a hard time, basically, thinking through how you would do a market-based approach, because volt vars don't travel very well, and so it's so localized you basically get down to a cost-based kind of service anyway. So, that's a tough nut. So, what we have now, to respondent 1's point, is we have the planning process that takes that into consideration, and I think it does that pretty well, but getting to a market-based solution is pretty hard.

Respondent 1: Just as a final point, when we think about these central grid services, you always get into this question of, well, how much of it just comes as a requirement for interconnecting versus as a market product? And I think reactive power's a good example where, again, VARs don't travel well, they're very localized, very specific, and I just think that's a fair comment when we think about these essential services. How much of it is just standard? It's kind of like when you buy a car. It comes with power windows. You shouldn't have to pay extra for that. It comes with tires. That's versus options that have a separate price. If we were to expand that to think about the ability of power electronics to control power flow and actually expand transmission capabilities, would your answer be different about how that should be valued?

Respondent 2: Possibly. I think the ability, whether it's using phase shifters and the like, to move power, I kind of view that as a grid asset that could be rate-based. We've done that. We provided phase shifters that we've rate based. So, when I think of the technologies like that, I think of them as an infrastructure asset that you can then ultimately optimize, ideally, into your market, but not as something that you would necessarily price separately in your market as a separate market product.

Respondent 1: I think FERC actually just had a conference on storage as a transmission asset, if I'm not mistaken.

They accepted comments on it, and that sort of thing, so one of our comments there was that there doesn't seem to be any reason why they couldn't treat storage as a transmission asset if it can be utilized to solve a transmission problem. But one of the things I think we'd have to look at is the interaction in the case where a resource is recovering all of its costs through a regulated transmission rate, and then it wants to participate as a market-based asset to provide some other ancillary service. What does that look like? So, there's some interaction there I think we need to look at, but there's certainly no reason, I don't think, why we couldn't get through those steps.

*Respondent 3***:** Just to follow up, I was on one of the panels dealing with that, and certainly from our perspective we're fine with competition, as long as everybody's competing on the same basis. So, we don't want to compete in the market against someone who has a rate-based structure supporting their investment.

On the subject of the new technologies and how they can get compensated, there's other stuff that improves interface capabilities. There are resources on the system that are designated as IROL (interconnection reliability operating limits) critical, and essentially that designation means that they are critical to providing a certain level of interface flow. If they weren't there, that wouldn't be provided. And there's actually a penalty for providing that under the new cyber security requirements, in that it moves you from a low security facility to a medium. And for a facility, that cost could be as much as a million dollars a year.

Question 2: I'm curious. Two of the panelists mentioned the possibility of price responsive demand to provide ancillary services, and what I have in mind is that, rather than thinking about frequency response, whether it's primary or secondary frequency response, coming from generation, why not have it come from the demand side? So, for example, if we have signals being sent to large building manager associations, like a pilot that PJM ran in Chicago at one time, where you can control air handlers, refrigeration, things of that nature almost immediately... The power electronics are a cool tool. But we already have thermal storage and inertial storage on the system that can move around, and we can avoid a lot of the problems that PJM is seeing with storage with the Reg D signal this way.

So, I'm curious why is it that we seem to be ignoring that, at least in the presentations here, for our purposes? And I know PJM hasn't necessarily done that, because there's a lot of demand response in the ancillary service markets, but in general, with a lot of these RTO markets, why are we not exploring that point further?

Respondent 1: Can I take a stab at that? Because in New England I think we are exploring that. First of all, we have over 1600 megawatts of pumped storage. That means 1600 megawatts of load that can be brought on if there's an imbalance that needs to be addressed, which is unlikely under current resource mix. That would all happen at the same time. But, believe me, we've already changed some of our pumping profile because of this economic dispatch based on price that's allowed now since March. When we have some of the solar coming in on a low load day, we may pump in the middle of the day. And that's just New England, with its slow penetration of behind the meter, relative to some of these other areas. I also mentioned in my chart that with respect to price responsive demand, which can include the very things you're talking about, that that will be fully integrated into the energy market in June 2018. So, it may not be at the pace that people would like, but it is happening.

Respondent 2: To the questioner, you're right. When I talked about markets driving innovation I neglected to emphasize how I think the very existence of the regulation and sync reserve markets at PJM has drawn demand response into both of those markets, and I think we're up to the point where 25%, 30% of our Tier 2 sync reserve requirements are met by demand response resources at this point. A somewhat lower percentage for regulation, but, behind capacity, the next two highest revenue streams for demand response of PJM were those two ancillary services, and energy is way at the bottom. So, I'm not sure I follow how it would help with our Reg D issue, maybe we can talk about that later, but certainly I agree with you that the existence of the markets allows this competition to occur, which allows demand response to compete right alongside. Frankly, it seems to me, since we're talking about changing behavior at the direction of the operator, frankly, I see this more as a supply side application of demand response, because you're paying it for providing a service. And I think it works well that way.

Respondent 3: I think it's a great question. I highlight this solar project just because we did the pilot on it, but I would love to do a pilot on how demand response could provide primary frequency response, because I agree with you. I think there's a huge untapped potential there that California should be looking at.

Questioner: Yeah, if I could just follow up on Respondent 2's question about the relevance of this to the Reg D signal, I think that the issue with the Reg D signal that you pointed out in your presentation is that with storage you get to a certain point, then you actually have to actually have it take actions that are actually hurting ACE. With demand response, you don't. Demand response can go in both directions very easily. You don't have to have that issue at the top.

Respondent 2: I agree that the real way to fix the Reg D problem is to take away the limitation. I agree 100%. Demand response wouldn't seem, at least in all cases, maybe some, to have those same limitations. Yeah.

Respondent 4: So, following up on this, it strikes me that you particularly have an issue where naturally occurring response to prices could have an impact in helping your ramp problems in California. I know that there is a study that was done, I think the person who did it is now a professor at the University of Michigan, but there was a study for LBNL showing that the majority of the residential demand in California could be shifted to other intervals just by controlling a degree or two of temperature in thermostatically controlled loads and doing that as if it were a battery. But that requires that you actually have some sort of wholesale settlements and pricing that gives an incentive for those kinds of actions to occur, and I'm wondering where you are in terms of thinking of how you might incent that kind of naturally occurring response as a way of dealing with your ramping issues.

Respondent 3: I think that's a great question. I actually think the duck curve isn't something that happens once in a blue moon. It happens every day, in the spring months, especially. So, you can get a lot out of DR just through time of use rates, the right structured time of use rates that could shift consumption from the head of the duck to the belly of the duck, I think, could get you the majority of the way there, and then to the extent you can layer on some dynamic pricing to help with some of the real-time volatility, all the better. But, to its credit, the California Public Utilities Commission is on a path towards developing time of use rates that align with what we call the flock of ducks, with the seasonal patterns of the duck curve to try to incentivize that kind of more systemic load shift that would come from time of use rates.

Question 3: I have a question, but before asking my question I would like just to comment on your question. There is a company, you probably know them, VCharge in Rhode Island. They've got a thousand water heaters, and they provide frequency response. What's interesting about that is that it's fairly low cost to implement compared to batteries.

But coming back to my question about batteries, and going back first to Speaker 1. You said at the beginning of your presentation that batteries or electrical storage should be valued less because of the duration they can be made available. You made a comment along those lines. I may have misunderstood, but from my days at Viridity, we would basically aggregate a fleet of batteries and respond to a single signal. So, for example, if I've got 10 batteries of one megawatt, I could put 10 megawatt capacity for one hour on the system. But I could also put one megawatt for 10 hours on the system. So, doesn't that imply that there could be some value associated with the duration? Because, again, from my days at Viridity, all that we had to do is to demonstrate we could respond in 15 minutes to the charge or the discharge signal, and then we would qualify.

Respondent 1: First of all, I am aware of VCharge and the hot water heater program. And we actually have one of those water heaters in our lobby at our tech center that actually follows the regulation signals. So, yeah, it's been very beneficial for us.

With respect to the Reg D, what I was saying is that since a battery can't sustain the charge or discharge for basically an infinite length of time, hypothetically, there is some downside, in other words, there's some maximum penetration of those types of resources before they're no longer beneficial to the system, because I get more of those, and I have to either add more Reg A, or I just don't get the response that I need for the duration that I sometimes need.

And the answer to your question is, yes, you can aggregate your resources together, but in your example, just to make it more simple for myself, if they could do one megawatt each for 15 minutes, or the full 10 megawatts for an hour, I think they'd want to get paid for all 10 megawatts for regulation, even though they can't sustain it for more than 15 minutes. So, yes, they can aggregate it together and offer less regulation, maybe four megawatts, or something like that. Because then they can sustain it longer. But, like I said, prior to January, they were getting paid for more regulation than they otherwise would. So that, I think, is the issue from their perspective.

And then, probably the one thing that is new since maybe you were at Viridity is that we've enhanced is the performance scoring and the performance requirements. So, resources that provide regulation no longer need to just demonstrate that they can follow the signal within 15 minutes. They need to follow it continuously. And we do a continuous performance scoring of resources. So, if we have a signal that is in one direction or the other for longer than a resource can sustain it, and it starts to not follow the signal anymore, that's going to show up in its performance score and affect its compensation.

Respondent 2: So, I'm just going to jump in here. I think one of the challenges, in particular with storage and thinking about how we integrate it, is that we've typically thought about this in terms of sort of buckets of products that we want. You can participate in this program.

You can participate in that program. But if we're thinking about fully optimizing a battery, I think that means not thinking about it as participating in one program. It means thinking about the battery as actually a market product that's participating in the market, and fully optimizing what it's capable of. New York ISO is starting conversations about how you would actually optimize all aspects of what a storage resource could do, but actually putting that in place is several years away. But I think thinking about it in terms of programs is part of the challenge.

Respondent 1: So, does this suggest that FERC's effort of trying to establish profiles for storage resources is something that might address this?

Respondent 2: Yes, I think that that's where they're starting to go. When they answer the question, "How can storage resources participate?" everybody says, "Well, they can participate in every program. You can be an energy provider. You could be a capacity provider. You can participate in the ancillary services market." But typically you have to pick one or two of those. You can't really do all three, and you can't do them all at the same time. And a storage unit could do all of that--and thinking about how you actually design the market around what they're capable of, I think that's what FERC was starting to get at.

Questioner: Yes, that's an area that is very interesting, because that's the multiuse of a single asset, and from a market participant perspective, that's what makes sense. Otherwise, if you're taking a single asset and a single market product, companies realize very quickly that the revenue is not sufficient to make it viable. So, a battery can provide demand response. It can provide VOC frequency regulation. It can provide reactive support. It can provide synthetic inertia, because you can simulate the response time to the signal and that was discussed this morning. It can provide restoration services during a black start.

And what we have been learning at Viridity and at AMS is that the market rules are such that you cannot stack those products very easily. For example, AMS is providing resource adequacy service to Southern California Edison. But can it also provide the same asset? Can it also provide services on the CAISO market? So, these are some of the obstacles that we have been asked to address, and they did something that deserves to be further studied. And that would be a big enabler to move things forward.

Question 4: What is the practical headroom for valuing and pricing essential reliability services sufficient to retain certain of the conventional resources that will be needed to provide the reliability? I understand there's a lot of discussion, both on this panel and the previous panel, of new technologies, or different types of resources that provide that. But, in addition, it's sort of a new missing money problem, which has been referenced already--providing revenue for these services in light of extremely low energy and capacity resource prices. So, I'm just wondering several have already, are already in progress. Will we be able to sufficiently value them, to keep some of the resources online?

And then my next question is, understanding the time it takes to identify, develop and then get approval for different types of services and pricing them, what's the risk we run that once some of this is in place, the system needs have already begun to change?

Respondent 1: Well, I'll start, because that second question is exactly what we're facing on the regulation side in PJM. Because we had a set of market rules that were put in place in 2012, not necessarily system requirements, but at least the market rules. And then when we saw the level of penetration that we got, we said, "Well, we've got to change the market rules, because they're not incentivizing things correctly." So, I think it can happen, not just with physical system requirements, but also with the way market rules are designed and it's something we need to keep watching for and trying to avoid at all costs.

On your first question, at least in PJM, energy and capacity revenues for resources far, far outstrip anything received from ancillary service markets. So, one vision of the future would say that your traditional sort of central station power resources will really be able to provide capacity and then provide energy and won't be required to provide ancillary services anymore, because of the penetration of these advanced technologies that can, in all likelihood, do it much more efficiently than a central station power resource would. So, I think if we're going to look at valuing resources like that to make sure that we keep what we need on the system, I think we better look to the primary energy product first and then capacity. That's just my thought.

Respondent 2: I have a little bit different answer to that. I think the market will determine what the headroom is, but I think the issue in going into the changing resource mix is, what are the conventional resources going to be needed for? Now, at some point technologies may replace them, but while they may have low variable costs, they have pretty substantial capital costs. So, it's not quite clear where the economic balance strikes out between existing and new. And so, one of the areas that I expect they'll be needed, in the short run, even before the new technology increases its penetration in the market, is for ramping. If you're going to have some uncertainty in the amount and timing of solar and wind on the system (and we're seeing it in New England), you're going to need to have some ramping around ready to address a change in circumstance. It could be a change in weather, which happens pretty frequently in New England, as we've seen.

Respondent 3: I'll just quickly respond to your first question. This is a real issue in California. We're long in generation. We have gas plants retiring. We're going to have a lot more retire. I wish I could tell you it's happening in a very orderly way, and that we're confident we're going to retain the optimal fleet that we would want, but that's not what's happening, to be candid. And so, it's a source of frustration for us and for the generator owners.

One of the ways we're trying to address it is through our resource adequacy program, where we have a specific requirement around flexible resource adequacy, where a certain amount of capacity has to have a flexible attribute. That definition today is pretty general. Almost any gas plant can meet it. We're trying to come up with a more rigorous definition that would help ensure the right resources are getting picked up. But there isn't a real clean answer to it. So, we have an active stakeholder process to sort that out. But the bottom line is, even if we implement a lot of these other market products in the spot market, at the end of the day, I know it's sometimes heresy to say around here, but I really think you need a procurement framework to ensure you retain that capability, and we've got a lot of work to do in sorting that out.

Respondent 4: So, I'll add just a few things, because I think there're a couple pieces that we've hit on here this afternoon that are pieces of that, and one is inertial control, which we rely on large spinning machines for today. Potentially, we can go to some form of synthetic inertia, but we're still in the early stages of being able to demonstrate that. Ramping is, of course, another capability that we have to figure out. Can we do it? Can we do it all the time, even when the sun is not shining, and what does that look like? And then I guess the other thing I would say, taking a little bit longer look at this, if we're going to very deep decarbonization and very high reliance on variable renewables, that becomes a much more expensive solution than if you have some dispatchable capacity that remains in your system. If you're looking at an almost entirely renewable solution, you might be thinking about something that had to have some very expensive transmission or storage investments, and potentially capacity as much as three or more times your peak demand. It gets very expensive, if you're looking at really deep decarbonization, relying entirely on renewables.

Now, the right price signal probably involves some pricing in that carbon market as opposed to simply trying to do procurements to deal with this. But we're obviously not there yet, and I suspect we'll have more discussion about that tomorrow morning.

Question 5: This is very helpful, and part of the discussion raises a question which I get into debates about all the time, so I wanted to try it out on you here. And it follows the earlier conversation about the multi-use of technologies in order to provide multiple benefits.

So, I'll pick on the *State of Charge Report* for the State of Massachusetts, about storage, in which they did a very careful analysis of the economics of storage and arbitrage--buy low, sell high, and do all that kind of thing, and they concluded it wasn't economic. But then they had all these other benefits that, when you added it up, were really terrific. And, therefore, we should mandate that people have to buy it, because it's so valuable.

And I have a somewhat different view of this problem, and this is part of the "get the prices right" story in thinking about this in equilibrium. You have to decide, at any moment in time, what you're doing. So, if the storage is providing regulation service at that moment, it's not also providing arbitrage services, or whatever, so there's a series of things that it can do, and you want to choose the one that's most valuable. And that's certainly true. But if you think about this as going forward in the future, equilibrium will be such that we'll see exactly what you described happened, which is that if we start getting too much of this stuff, we're going to change the prices until we don't get so much of that stuff. And so, the markets will adjust, so that the people who are providing these services will be indifferent to providing the regulation service versus providing the arbitrage. They can use it for one or the other, and their prices will adjust. So, you can focus on just the arbitrage part of the story to decide whether or not it's economic. You don't have to go through all these other kinds of components. Now, the exception to that would be something which was a true "and" service. And I'm trying to think about this. So, inertia might be an example of something where you can provide energy with the spinning, rotating axle, and then you've got inertia coming along with that at the same time. And so, that's an additional service, and you don't have to not provide the energy in order to provide the inertia, as I see it. But for most of these things, it seems to me like that's not true.

So that implies that the multiuse argument is really just the equivalent of saying, "We have a dumb pricing model for regulation, and I can go make a lot of money on regulation with this equipment," but that isn't going to last very long, and then it's just going to equilibrate, and then it's going to turn out that basically, when you do the economics of arbitrage for storage, about buying low and selling high, that's the story. And if it's uneconomic under those circumstances, you're not going to save yourself by finding multiple other kinds of applications, if they're just "or" applications: "you can do this or you can do that." You'd have to find something which is a true "and," so you can do both at the same time. And I don't see very many things that are both at the same time. So, this gets me into a lot of trouble with my storage friends around here. Obviously, if the Governor heard me say this about his delightful mandate to buy storage in Massachusetts, I'd be in trouble. But am I wrong?

Respondent 1: I think it depends on what you're looking at, and it depends upon the resource you're talking about. Some of the batteries like to use their full range from charge to discharge, and most of the installations are able to be providing energy and operating reserves in a synchronized state. We can also have a range set aside for regulation. So, the size of your resource and the amount of range that's available for dispatch can have a great bearing on whether you can provide multiple services. I think you're right. You can't provide the same service from the same megawatt hour, unless you're on regulation, and the range that's not currently activated is by definition operating reserve.

Respondent 2: Well, does it matter where you're located? If you're on the distribution system --

Questioner: Not for my argument, no. I'm making a long-run equilibrium argument, which is that the system will adjust, so that as long as you can't use the same megawatts at the same time for two different applications, then the two prices will equilibrate. And so, if you can't make the money over here, you're not going to make it up in volume over there. [LAUGHTER]

Respondent 3: I think there's merit to what you're saying from a simultaneous standpoint, for the most part. There are exceptions, as you noted. You could certainly provide inertia and energy. You could provide frequency response down capability and energy simultaneously, so if there were a market for that service, you could do it. But, more importantly, about multiuse, which is I think where most of the storage communities are coming at it from, is, are there times where behind the meter storage could provide services to the customer? Are there times when it could provide services to the distribution system? Are there times when it could provide services to the transmission customer? And how do you develop a model that would figure out what it is doing when? And then how do you stack that compensation? In theory, it's possible. In practice, it's very complicated. We're trying to work that out in a stakeholder process that we have ongoing. So, I think there's a way to stack values, recognizing that many of them can't be provided contemporaneously, but it's complicated. And I think that's what the storage community is looking for us to solve, and we're trying to work through it.

Respondent 4: So, to the questioner, I think you're basically right, with those couple of exceptions in terms of the things that you could do. You have three basic kinds of electrical products. You have real power, you have reactive power, and you have various kinds of reserves. And you can only use one unit of capacity, generally, to provide one of those at any single given point in time. You can't provide multiples, with a couple of exceptions that Respondent 3 noted.

I guess I would add two other complications. One is that whether you reach equilibrium or not depends upon whether your pricing is co-optimized. If you're not co-optimizing your regulation market with your energy market, you're going to have a problem. The other qualification, which I have some concern about whether FERC actually understands or not, is about whether you can do something that is simultaneous in the distribution system and in the wholesale market and have, for example, a wholesale market aggregator begin to decide which storage facility it's going to operate at which point in the distribution system, without in some way impairing the operation of the distribution system if you do very much of that. And I think that's an issue where we need to think about the control architecture in order to make those things work together, rather than create potential conflicts. So, those are my two additional qualifications.

Respondent 1: I'd just add to that, if you're trying to pay for a service, maybe to the end use customer on the distribution level, maybe for distribution system support, the question needs to be asked, how much of that resource is left for the ISO to access for the purposes of managing their system? And I think a bunch of those issues haven't been answered. The Commission had put out their Notice of Proposed Rulemaking, and I think that aspect of the proposed rulemaking was the area that still needs the most work.

Comment: Coming back to the multiuse here, the demand response is on the one hour time segment. The fast regulation is on a two to four seconds time segment. So, there are a lot of things you can do within that one hour, so that you can do both concurrently. Sometimes you provide more frequency regulation, sometimes you provide more demand response within the hour. So, there is a way to get there without introducing conflicts. But somehow there needs to be some flexibility in the rules. But that's potentially very interesting, because if you use a battery just for frequency regulation, like Viridity is doing in some cases, it's fine when the prices are in the $25 to $35 a megawatt hour range. But when prices are going down to $15 per megawatt hour, you're stuck with a 10-year investment, basically. So, I think it's an important problem to solve, to find rules that enable a fair multiuse of the same asset otherwise it's not going to be very successful.

Respondent 3: I would agree on the comparability. In fact that's what actually prompted the changes that will be implemented in June 2018 in New England, is that the demand response resources, which had been only scheduled in emergency periods, will now be price responsive based on bids, and on a five-minute dispatch. So, those services will be provided through there.

I think the question I had raised earlier is if there's other things happening with that same device behind the meter or for the purposes of distribution system support, what does that mean with respect to the access that the system operator has to operate it in the direction needed for its purposes?

Respondent 5: I just wanted to chime in. I think this question and the premise on the equilibrium prices is really spot on. I'm not sure that I agree with Respondent 3 about the possibility of doing regulation down and providing energy simultaneously. You're either moving down or you're moving up and, I'm not sure that that works.

But there was something else that the questioner said that I think is really important here that we haven't talked too much about, and that was inertia and spinning mass. And I think part of the problem that we've seen in some of the RTO markets is the incentive to follow dispatch. When there is something happening on the system, and inertia would say, "ramp up," we have generation owners holding their units down so that they follow dispatch and avoid imbalance penalties, which actually makes the ACE problem and the frequency problem worse, which means that we then need to get other resources to respond even more, whether it's fast response resources such as storage or general thermal resources. So, we've created an energy market design that actually disincentivizes that primary frequency response with the inertia, as it stands now. And so I think that's part of the problem—otherwise, generation owners face the problem of being penalized for not following the dispatch.

And what we hear from some of the people who are installing storage or micro grids is that they are saying, "I'm doing this for my own individual reliability." But if they're using storage for reliability in case they have an outage on the distribution system, for example, but yet they're injecting power for the wholesale market, you can't have it both ways there, either, and I think that's a good observation to make. and it's one that we haven't come to grips with yet. So, I just kind of wanted to just throw that on there, but I think with respect to the inertia thing, there's other things going on in the energy market that are creating more of a problem than is necessary.

Respondent 3: I just wanted to comment quickly on these last comments. First off, on my comment about providing simultaneous service. That comment was made with respect to providing an energy schedule such that, along with it, you're providing a frequency down capability--not that you're being dispatched down, but you have the capability. So, you're being paid for the fact that you have that capability to respond if there's a need for you to respond, from a frequency standpoint.

On your point about potential conflicts with a real-time dispatch and what the physics are saying, I completely agree. That can be a real issue, especially when you incorporate the latency of a real-time market dispatch, where the grid can change dramatically in seven and a half minutes, which typically is what it takes for a five-minute dispatch. We talked about this issue and even contemplated that, should there be an override, a generator should not respond to the dispatch signal if it goes against the frequency, it's experienced. That's something we'll have to look at because as I said, the system is moving, it's a lot more volatile in this new world, and seven and a half minutes is an eternity in terms of how the dynamics and the system can change. So, it's a very good point.

Respondent 4: I think we're also going to see more and more devices that are going to see local frequency, local voltage, whether it's at the distribution level or maybe even at the transmission level, and begin to respond, and those are aspects of the system we don't have today, and it won't just be large generators seeing that, but we're going to have to figure out how that integrates into our market designs.

Question 6: Thanks for the interesting discussion, especially on the multiple uses of storage. I was wondering about the comment that was made about storage having multiple uses that they should be compensated for, but why does that break down when you look at the uses of storage as providing a transmission service, or some service that is receiving cost-based recovery, in addition to a service that may be receiving market-base recovery? And I understand that folks in the markets may not want to compete with resources that are receiving these out-of-market payments, but doesn't this resource look like a particularly efficient resource? For example, if I'm providing a lot of benefits at some cost, I can provide some of those benefits and get compensated for some of my costs elsewhere, and then I have other additional benefits to provide to whatever market it is that storage would be bidding into.

And so, how would you distinguish that from, say, just a very efficient gas plant or other form of generation? And then, some generation apparently also gets cost-based recovery while also being participants in the market. So, how would you distinguish that case from what you're objecting to with storage receiving cost-based as well as market-based recovery?

Respondent 1: The problem is that it's not competition at all. If someone's going to come in and what they make in the market has no bearing on their investment or their future viability, that isn't competition, and it's going to hurt the signals that our facility relies on to provide service. And we have ongoing needs to maintain it. So if it's useful to the system, we want to make sure the signals aren't being interfered with.

To go to your last point, there is no difference with the cost-based resources that are being brought in for other purposes--procurements for the states to meet some other needs. That's, in fact, the issue that's before the Commission right now. How do we solve the intersection of those policy needs in the competitive markets without crashing the competitive markets? So, there is no distinction there. They're both problems that need to be addressed.

I also want to highlight that where you stand depends on where you sit. Everyone thinks that they have something unique to bring to the market. I think I have a pretty unique product in a pumped storage facility. One thing that needs to be understood, though, is that every resource on the system supports the transmission system. The question is how it comes into the market to support that. For example, I mentioned that a resource has been designated as IROL (Interconnection Reliability Operating Limit) critical. That's not something they sought, that just kind of happened. If you don't plan out the system, you have no idea whether or not it would have that contribution. Those resources aren't provided at a cost of service based rate, either. The way the markets currently operate is, if you want to come in and participate in the market, you do it through the market. They still have the state contract issue that needs to be addressed. How do you merge those concepts? So, it's really not unique. I think the unique aspect of the storage may have more to do with the reaction time of going from not producing output or absorbing real power to doing so. That certainly is quicker. It's something that they're good at. That's why they go in the regulation market. But I think that if you're on line for a purpose that requires that type of response time, you're probably there for some type of contingency protection. And I think it gets to the same point as the behind the meter customer looking for backup power. I don't know how you do both. I don't know how you provide contingency protection for a distribution system or transmission system while also participating in the energy market as an economic resource. There are uses like voltage support, where they're not mutually exclusive, and now we're back to the question of, why is this much different than a generator that also provides reactive support?

Respondent 2: Respondent 1, is your concern at all mitigated by the responses that former Chairman Bay and Commissioner Honorable gave in the majority opinion in the policy statement, where they talked about two services separated in time, and the allocation of cost so that only a portion of costs would be recovered through rate base?

Respondent 1: To me, that sounds like it's simply a cost-based rate with market revenues netted out so they could care less what the price in the market is, and that's where the problem comes from. If you disturb the market, you're going to reach an equilibrium differently, and maybe inefficiently, because the resources that weren't receiving the subsidy are going to have different economics and may need to exit the market or not maintain their facilities as well as they could if they had a market that didn't have the disturbance. For these resources, whether it be maintaining equipment or even licenses, what they're willing to pay to maintain flexibility has a lot to do with how the market is going to value it. And the amount you want to fight those things and pay for them really has a bearing on the cost in the market. So, companies like ours get very worried when we hear about someone trying to mix those two.

Respondent 3: Yes, and I'll add that we're in the process of a project with Con Edison in New York City. The project is a mobile battery storage solution. And a big part of what that project is testing is third party ownership of that kind of an asset that can participate both on the distribution system and in the wholesale market. So, I don't think it necessarily has to be something that's rate-based forever.

Question 7: Thanks. Great panel. To the earlier comments on value stacking, my biggest bugaboo about the value stacking idea is the idea of stacking, at the wholesale level, energy arbitrage and capacity value. And I think all of us realize that that's just not a compatible combination of value--that the same resource cannot be cycling to arbitrage energy and then be given full value for its maximum usable capacity, when it's going to be empty or half full more than half the time. So, that, to me, just doesn't make any sense, and it has its corollary at the retail level, where you have entities like Tesla's Powerwall. You can go to their website, and they are marketing the idea that you can use the battery to cycle your solar energy, but it also backs up your house. So, after you charge the battery during the day, you discharge it during the night, and then if the outage comes at seven a.m., your battery is empty. So I think there's going to be some very unhappy campers, to the extent a lot of Powerwalls get sold on that basis. So that's one side.

But I wanted also to say that I was interested in what Speaker 2 had to say about how the

California Commission is going to look at the time of use rates. Right now, in Southern California, the high prices are in until six p.m., and then the low prices are after six p.m., which is exacerbating the duck curve. I mean, it is telling people to do exactly the wrong thing. And I realize the California Commission says, "Oh, yeah, we're going to have a look at this and think about this." They're targeting a decision for, like, January 1 of 2019, and they're going to grandfather net metering customers for the next five years after that. So, it's not like there's a sense of urgency, and I just really don't get that. And what that, it seems to me, is forcing people to do, is at the California Commission level, they're telling the utilities to get hundreds of megawatts of hugely expensive battery storage, and they're essentially forcing people to come up with new products, whether it's flexible resource adequacy or a load ramping product, and to do all these kinds of things which presumably wouldn't be necessary if the retail rates were rationalized maybe a little bit sooner, like yesterday or something. I'm just interested in comments on that.

Respondent 1: You're preaching to the choir. [LAUGHTER]

Respondent 2: I didn't want to respond to the California part of it, but I did want to respond to the point about the end use, because there is an issue that we haven't talked about yet, and that's jurisdiction. If you have a resource that's participating in the ISO's markets solely for charging and discharge, it is pretty clearly going to be a FERC jurisdictional rate, and so it can buy and sell at the LMP. If you're going to charge using the LMP and then use it for end use purposes, I think you have a problem there, because now it's a use for end use, not a use for resale.

Respondent 1: I'll just tag on a little bit to your first comment on the stacking. I think I see what you're saying with respect to storage energy arbitrage and capacity value. But I don't think I totally agree. Because we have had pumped storage in PJM that's gotten capacity credit for ages and ages and continues to, under capacity performance. It may not be able to do so for its entire name plate capability, but I certainly think there is some room for the assumption that you'll be able to generate during an emergency when you're necessary.

Respondent 2: That does have something to do, though, with the duration that the pumped storage can actually be expected to…whereas a battery is typically four hours.

Respondent 1: Correct. I just didn't want to be applying that idea to all storage. I saw what you're saying as far as maybe the typical battery, if you will.

Respondent 3: So, just a couple of quick things. One is just to note, in terms of the charging of batteries, at least in some RTOs, I know in PJM, the distribution company can charge a distribution rate for the charging cycle of the battery that becomes part of a FERC-blessed rate, even when it's playing in the wholesale market. I guess the second thing is that one could imagine a market where one sequentially dispatches, for regulation, batteries that have, let's say, one hour duration, and you're simply going up a stack, as opposed to requiring a service to go 10 hours.

Respondent 1: Right, but then, like I said, that combination would have a single regulation capability, as opposed to an additive regulation capability of all of theirs. But absolutely, positively, yes.

Question 8: Talking of new technologies, there was a technology called the synchronous condenser that's come back into fashion. It's basically a motor equivalent generator that's applicable in Southern California. They're applicable in Texas. And there's other parts of Europe that are looking because of the lack of inertia. So, from a cost comparison they're equivalent to modern FACTS(flexible alternating current transmission systems) technologies today with the high availabilities. It doesn't have the fast acting, millisecond response time, but it has the seconds response time. So, they're very much in the market today and I was just responding to some comments about technology that was or was not available, but technology 40 years ago has come back, and it still has its role to play with things like dropping coal based units coming off the grid, and losing that inertia. And I need to research more on synthetic inertia as well. That's sounds like an interesting topic.

*Respondent 1*BRESLER: In the last several years, we actually converted some generators to synchronous condensers in areas where we saw a voltage problem as a result of retirement. So, yeah, absolutely. It's part of the portfolio for sure.

Question 9: I was sort of hoping to come away with some of the answers. [LAUGHTER] And I don't know that I have them. Does anyone have any thoughts on whether or not we can value these resources, or is it just that for some of our essential resources, we just have to say, "In order to interconnect you have to be able to do this?"

Respondent 1: I definitely think there is opportunity to value more in the markets. I think for the regulation market, as I noted in my presentation, there's plenty of room for improvement in how we design that market. For frequency response, primary fast response, we're taking a hard look at whether we need to do a market product there. I think there's some potential for it. I won't say we'll definitely go down that path. But I think there are some things, like reactive power support for voltage regulation, where I just think that's kind of an inherent thing that a grid connected resource should be able to provide, and having a market to extract a value out of that, I don't think is very practical. So, that's my answer.

Questioner: I just wonder if the expectation is that the value we're placing on these services is actually going to be sufficient, recognizing these fundamental changes that are happening--that the energy prices are low, and they're probably going to stay low. And capacity markets are likely to continue to be distorted. So, what do we do to make sure that resources that are here today stay here through this transition, and what do we do to make sure that those prices for these essential services are high enough to attract the kind of resources that can be flexible in the future? I don't know the answer.

Respondent 2: From PJM's standpoint, certainly, we're looking at a suite of ancillary service-type issues. We've been looking at black start. We've already started our frequency response conversation. As I said earlier I think we need to take a serious look at load following, but if we're talking about maintaining existing resources and valuing existing resources, I'm not sure ancillary services are the entire answer. And we think we need to take a serious look at price formation in the energy market, because the capacity market is an issue, with respect to some of the things that are going on. We certainly agree with that, but the bulk of this is in the energy market, and that's where it should be. And maybe we won't decide to make any changes. I don't know. But we need to take a serious look at the way prices are formed in the energy market. That wasn't the subject of this panel, so I didn't talk about that today. It's out there.

Questioner: I guess I just keep coming back to the idea that if the expectation is we have a lot of renewable resources that have very little cost, where are the energy price signals going to come from? Will there be an energy price signal, or is this all just going to be in ancillary service or essential service price?

Respondent 2: Maybe in California, when they get to a 100% RPS, you've got to answer the question as to where the energy price will come from. Until then, something else is providing energy, if you don't have 100 percent renewables, and we ought to make sure it's setting price. So, that's where we're coming at it from.

Respondent 1: I have my own concerns that the energy market isn't going to do it in the short run. It's not just renewable entry, its low gas prices, and where before it was Marcellus, now it's the Permian Basin. What's next? Gas prices are probably going to stay low for a long time.

You could say that, "Well, if these resources leave, the energy prices are going to increase during some periods when the renewables aren't delivering." I don't think the system operators are going to wait around and take the chance they're not going to have the ramp available to keep the system secure. So, they're going take actions anyway. The actions they're going to take are really focused on some ancillary service that's behind what they will do to protect the system. In New England they're focused on the ramp, the multi-tier ramp, and that's their next priority.

Respondent 3: So, differing a little bit with the last comment, on the voltage side, I think there are particular things that can be done on distribution that actually have voltage support implications for transmission. And if you price it right, you're more likely to get the most cost-effective mix there. So, that's something that perhaps you ought to take a look at. I will say, briefly, that if we get the energy prices right and we actually have shortage pricing, that will begin to get more response, and I will add to that something that I've talked about here before, and that is, we have to get it right in terms of wholesale markets, particularly where there are competitive wholesale markets. We have to get the load side settlements of that right, and not simply be stuck with zonal hourly pricing, if we expect load to play a major role in balancing these resources.

The final point I'll make, because I don't think anybody ever came back to your point about gas market interactions. which I think is an important point, is that we're doing a panel next week at the DOE Electricity Advisory Committee on gas-electric interaction. There's actually some very interesting work about how to combine gas and electric markets and co-optimize those. It has been funded by DOE, and I think that, combined with some of the discussions of resilience we've had over the day is maybe a future panel at HEPG, to think about how to look at that issue in greater depth.

Commenter 1: Well, this is just a brief answer to the challenge here. [LAUGHTER] I think the comment that low natural gas prices are a problem, and we have to do something in order to deal with the problem of low natural gas prices, reveals how crazy the market design is in many of these situations. I mean, low natural gas prices are a gift from God. And we should be delighted that we have low natural gas prices, because it's happened because we have efficient technologies, and we have huge resources. And we always get confused talking about renewables, because it's subsidized, and it comes in with low variable cost. But if you go to the market design story, and you ask yourself whether our low natural gas prices and the flattening supply curve are a problem or a solution, the answer is, in the theoretical case where you have adequate scarcity pricing and demand participation, that it's a solution. It's not a problem. So, when we say it's a problem, what we're revealing is we don't have adequate scarcity pricing. That's the fundamental problem. And if you don't fix that, then you're doing all these other patches. So, go to Texas. [LAUGHTER]

Respondent 1: I agree about the gas price comment. I only identified it because if the belief is that there is a need to maintain some of the conventional resources, they're simply not going to get what they need from that market, for the very reason you cited, and that's not a bad thing for consumers. I think the question on reaching the scarcity prices, though, has a lot to do with when the ISO makes sure the system is secure, which is generally on a day-ahead basis. So, some of the actions that they would take to maintain system security could very well dampen some of the signals that might otherwise be provided as scarcity to give the signals for flexibility. And I think that's a dilemma.

Respondent 2: The one question I have is, if you have a hypothetically flat or nearly flat supply curve, how do you get resources to follow dispatch in real time and follow load? I would love to talk about that. I understand the price formation part. I understand the scarcity pricing part. Without an explicit load-following product, I don't know how you do that.

Respondent 4: Doesn't New York penalize people who don't follow dispatch?

Respondent 2: Would we rather rely on penalties or incentives?

Respondent 4: I don't know. Does it work in New York?

Commenter 1: Wait a minute. But if you have the truly flat supply curve, you don't care, because somebody can come up and make up for it. They don't cost any more. So, those things can't happen at the same time. My point is, if it's truly flat, that means you have lots and lots of resources around there that are available that have the same cost.

Respondent 4: That's my question.

Commenter 1: Yeah. But that's to me is a second order problem that we can talk about. But I think there's nothing, in principle, that says a flat supply curve is any more of a problem than anything else, and I think it all has to do with the scarcity story.

Respondent 3: So, do you think it's a problem?

Commenter 2: I go back to New York. What we focus on is a couple of things. One is revenue adequacy of needed resources. And the key idea is "needed." And the other one is we need the performance from these needed resources, too. So, in New York we are trying to get to 50 percent by 2030. And in our calculations, in a planning analysis, it means that we have to add 15,000 megawatts of new intermittent resources to get there. Out of that there is about 9,000 megawatts of solar and about five or six of wind. Now, what that means is that some of the conventional resources may not be necessary. If you have 15,000 megawatts of intermittents, they're coincidence at the peak would, say, 30 percent average. That means 5,000 to 7,000 megawatts of conventional resources may not be needed for classic resource adequacy. But, for us, that means about 30,000 megawatts of conventional resources have to have sufficient revenue adequacy. And everyone is right to note that infra marginal revenues are declining. There's going to be very little infra marginal energy. For capacity markets, we have to see whether the capacity market responds or adjusts, but ancillary services… or essential services…are very important. We have to look at revenue adequacy of needed conventional resources, which could be gas turbines and combined cycle units. Given the current products we have, and the cost of new entry, if it's a a new gas turbine, or a conventional combined cycle, how does it recover enough from the current products? If not, when we have a lot of intermittent resources in the market, we need new performance measures. Like, if there was 9,000 megawatts of solar, and there's a cloud cover that comes through quickly, you will need startup and ramping. So, we saw a list of a lot of products, from frequency response to voltage to fast start to load following—for all these products, we have to see what we need and what time domain and how we price them. And, in total, they have to get revenue adequacy. So, those are the kind of things we are discussing in our stakeholder process, and, again, the two important things are revenue adequacy and performance.

Question 10: I'd like to follow up on what was said about how there's tremendous potential for co-optimization between gas, and electricity. And that is very true in the process industries, where you are using natural gas, for example, to produce steam and electricity to feed the various areas of a process, and we have looked, in Belgium, in a phosphate plant, at a potential project where we can actually provide primary frequency response capability by playing between the production of steam and production of electricity.

But, back to the panel, something we haven't talked much about is congestion relief. There are a couple of interesting initiatives back in Europe. One is being studied by the Association of the European TSOs (ENTSO-E, the European Network of Transmission Service Operators for Electricity, and the French RTE, which is the French grid operator) which is studying the concept of avoiding new transmission by installing a battery at both ends of a congested line. And, basically, by symmetric charging and discharging of the battery at both ends, they can provide a net zero balance, basically, on the system, whereas they eliminate the congestion. Just looking at that…and there is so much more potential in the markets and the PJM or CAISO and markets of adding other products to that. Once you have the battery installed, that battery can provide voltage support, for example, and a number of other services. So, this is one input. Basically the other one is, we talked a lot about dynamic line rating this morning, and what's preventing it from happening here in the United States, and I was wondering if you had some remarks about what does it take to get dynamic rating taking off in the US?

Respondent 1: It takes convincing a transmission owner that it's cost effective to install it in their system. That's been a challenge, I think.

Question 11: I just wanted first of all thank the person who asked Question 9 for stirring the pot, because I was feeling the same way, that we were walking away from something that had a lot of questions left on it. And I'm going to ask a really bulleted question. I just wonder, as a macroeconomist, if we're maybe micro-ing the hell out of this, and trying to chase the evolving problem and find the price signal in the really small markets on the really evolving changes, and whether maybe, efficiency losses notwithstanding, we put the price signal in the bigger markets, which is the capacity market or the energy market, and then require the obligations to be there. So, I'm kind of channeling my system operator who every day says, "Well, why the hell don't you go out and buy the right products, instead of sitting here relying on your little merry price signals to solve it?" [LAUGHTER] So, that's a quote from someone else, but I just wonder, why don't we go back and put the price signals in the big markets then?

Respondent 1: I think the answer is, yes, it would make sense to focus on those, because we still have some gaps in the primary market. I do think, though, that where a system operator like New England has identified that, "Hey, we're worried that that still won't provide us with enough of what we think we need to control the system," then we need to be listening to what they're saying, because they know and see a lot more than we do and more than they can actually show us…but I agree. We are trying to micromanage things a bit here.

Respondent 2: I don't know if I would call it micromanaging, but I think, going back to that paper that I referenced about what lies beyond capacity markets, and tying it to what NERC is looking at and how they suggest you actually think about and plan what you need, they say you should recognize where you see responsive demand, recognize where you see behind the meter resources, where you see all these different renewables coming in, and forecast your net demand. And that tells you what your ramp needs are, and you just price that, and that's what you go try to procure. And this is why I keep coming back to the gas system, because for so long we focused on just coordination--making sure that everybody's talking to each other and everybody at least sort of speaks the same language and understands what happens on each other's systems--but I was pretty struck by what I learned when I was working on a lot of that, which is that even if you have a firm transportation product on a pipeline, and let's say it's even no-notice, so, if suddenly the sun goes away, you can just say, "I have this ramp need that I procured and that I planned for," and let's say it's a gas resource, and it's just going to come on. Even if you have no-notice firm transportation, you have to be connected to a pipeline that has access to storage. And Arizona had a lot of problems with thinking about how to coordinate gas with a lot of the solar that they were seeing, and they're all on firm transportation. But they don't have a lot of storage. So, they were seeing issues. New England, we all know, doesn't have any storage capability on the pipeline system, so I don't know what the answer is to whether or not it's too micro and we can actually do this on the macro level, if we don't think about contingencies on the gas system, where we're expecting all of that to be provided.

Respondent 3: There is a facility in Everett, Mass. that provides storage and can be a great balancing resource for the system.

Respondent 4: I will say one thing briefly. So, we can do a lot in energy markets if we get the prices right and get shortagewww.www pricing, but that's still at basically like a seven-and-a-half-minute delay to get there. That's the latency, and so, you still need to do something to manage the volatility within that, and that's where regulation and power electronics come into play.

Comment: The short answer to the questioner is, that's why we have locational marginal prices. Batteries are not economic based on actual prices. That's why we don't have them. That's a good answer. Why do they have them in Europe? Let's see. Do they have locational marginal pricing? Thank you. [LAUGHTER]

Question 12: I just have to defend the gas industry, because its demise is sorely overstated. We had LNG in New England. New England chased the LNG out. It can come in. My former company has trucked gas in during the polar vortex, so I think the demise of pipelines is overstated, and the benefits of gas generation are understated.

Moderator: OK. Well with that I think we are at the demise of this panel.

Session Three.
Re-regulation Redux? Or, Can We Sustain Competition?

While competitive electricity markets have emerged over the last two decades, recent trends in policy, law, and technology have raised questions about their sustainability. The open, competitive market is under attack. The basic question we may be facing is whether we are evolving away from markets and back to regulation. Utilities have sought to transfer assets back under rate base or contractual equivalents thereof. ZECs and DECs are on the table in many jurisdictions. We have substantial growth, often with policy support, of more subsidized zero-marginal-cost generation. For non-renewable IPPs, with no rate base options or public support to fall back on, there may well be a significant "missing money" problem. Some have even contended that there may be regulatory "takings" occurring. Is there a trend toward re-regulation, and, if so, is it good policy? Is it reversible? What measures, if any, should be put in place to restore/assure the sustainability of a competitive marketplace in electricity?

Moderator: Good morning. We're going to talk about re-regulation redux, and I thought I'd start with a couple of really bad metaphors. Let's start with one that we love at HGPG, the orchestra. So, can the orchestra ever play in tune? Or how about this one? Has Humpty Dumpty fallen off the wall and can we put him back together again? Can we unscramble the egg? Or, to quote a famous fowl, is the sky falling? And all of our panelists will address this issue.

Speaker 1.

I want to start off with just a couple of basic facts about PJM before we talk about what it all means. There's been a lot of talk about fuel diversity. Well, we developed a couple of simple indices, and you can see that, really, fuel diversity, if anything, is increasing. We calculated that both on an energy and a capacity basis.

Everyone knows that gas is cheap. Gas has been very cheap, and the result of that is to make combined cycles cheaper than coal. Combined cycles are the new baseload.

This chart just compares the cost of combined cycles and combustion turbines (CTs) to coal plants. And you can see that generally even a CT has been cheaper than coal, but you can also see that gas is very volatile, and when gas gets expensive it gets very expensive very quickly.

There has been a lot of talk about whether it's profitable to invest within PJM. This chart simply shows, since 2009, whether it was profitable for a new combined cycle to invest in PJM. Seven to nine Eastern zones have been profitable consistently for the last three or four years, even with dramatically low gas prices, because they're basically, actually, in this case, they are making it up on volume, because of the differential between the gas costs and the LMP. But, by contrast, coal plants have never been profitable in PJM, at least since 2009, and are not going to be any time soon. It would not make sense to invest in a coal plant, as everyone can see there. Same thing's also true for nuclear. The economics of nuclear and coal are very similar, given the net revenues from nuclear. The net revenue from 2009-2016 is way, way below the actual investment costs for a new nuclear power plant, meaning that, of course, it would be uneconomic to build one in a market, in PJM.

So, there's been a lot of talk about why we need subsidies and units that are non-profitable. This is a somewhat complicated table, but it looks at avoidable costs recovery, ACR's, think of it as annual out of pocket costs. So, from an economic market perspective, you get a retirement signal if you can't cover your annual out of pocket costs. You're better off if you retire. You're actually making more money.

Conversely, you're better off not to retire if you're more than covering it.

So, one of the things this demonstrates is the critical role of capacity markets in PJM, because most technologies are not covering their costs, even their avoidable costs, without capacity markets. But even given that, focus first on the coal fired row, which is the fourth row down, all the way over to the right. So, the percentage numbers are the break points between the quartiles. So, you can see that even the median is about 85 percent of avoidable costs, but the dividing line between the third and fourth quartiles is 131%. So, simply put, not all coal units are losing money, although many of them are.

If you go down another couple of lines to nuclear, again you see the breakpoints between the quartiles. So, we see that, in fact, nuclear units are doing better than coal units, but the basic message there is that not all coal units, not even close to all coal units in PJM, are losing money, and, in fact, both coal and nuclear units, but nuclear units even more than coal units, are very sensitive to the actual level of LMP. In the first quarter of 2017, LMP was up 13%. When you redo these numbers for 2017, none of the nukes are below it, in terms of avoidable costs. So, it's very sensitive to the actual level of LMP, and we're nowhere near the sometimes allegedly disastrous economic results for nuclear that have been alleged.

This chart here is the famous flat supply curve that actually doesn't really demonstrate that it's flat in actual operations, and is not, actually, as was pointed out the other day, a problem for LMP.

So, what's the problem? Everyone has been talking about a problem. What's the problem? The problem, in a word, is competition. Right? That's the problem. Competition has actually happened in wholesale power markets. It's driven prices down. And, lo and behold, for some units and some unit types, in fact, particular units are uneconomic. Because they've become uneconomic, they're now looking for various nonmarket solutions.

So, to address the question of the panel, what's the solution? Well, clearly, the solution, in the short term, is subsidies. That's the only solution I can think of. So, we've seen them in Ohio for coal and nuclear power plants, at least proposed. We've seen them in New York, Illinois, Ohio, New Jersey, Pennsylvania, all for a specific uneconomic units, and all of which demonstrate the maxim that, in fact, subsidies really are contagious. If you get a nuclear subsidy, you hear, "Well, it's not really fair that I don't get one as well." And there's a certain logic to that. If you can get a nuclear subsidy in Illinois, why not in Pennsylvania? Why not in New Jersey?

The longer-term solution, going down that same path, is to re-regulate, and we have to remember that states really do have the authority to re-regulate. And I think, once you start down the path of subsidies, we're going to get to re-regulation almost inevitably. The irony of all this, and I think is probably not lost on any of you, is that the reason that we have competitive markets, and we had PURPA, was because nuclear power plants cost too much. They were putting billions of dollars into rate base, huge overruns. People wanted competition to try to constrain all that, constrain regulation. So, we introduced competition. Competition's been very effective. The combined cycle technology really exists only because of competition. But it would be truly ironic to end competitive markets to protect the nuclear power plants from which competitive markets were intended to protect us in the first place.

So, that's a long way of saying that in my view the market paradigm which we have in PJM and the quasi-market paradigm cannot co-exist. If we're going to start subsidizing and start re-regulating, then it really is, I think, virtually inevitable that that's where we end up. And, of course, I don't really think either of those are the preferred solutions. The preferred solution is to let competitive markets work. Competitive markets have been working very well in PJM. It's not to say they're perfect. We've heard lots of suggestions about how to make things better yesterday, in the first and second panels, the first panel in particular, but there really is no defined market design problem to which subsidies are an answer. I've yet to hear one.

So, the various arguments for subsidizing nuclear, for example, are that it's low carbon, but the fact that its low carbon is interesting, but does not make it the preferred solution. So, everyone, I think, agrees that a carbon price would be preferred, and there are lots of ways to get to that. I actually believe that PJM states could agree on a carbon price if we all did the work to demonstrate what the actual outcomes would be. But even if you can't get all the way there, having an auction, if you really believe that carbon is an issue and you want to address it, having an auction for low carbon resources would be preferable. And having rational renewable portfolio standards by states which incorporate a consistent view of the value of carbon would also be useful.

Fuel diversity has also been put out there as a reason. I think one kind of counterfactual just to think about when you think about whether fuel diversity is really a reason, is, if we were going to start up the system today, would we really build, given the graphs I just showed you, would we really build coal and nuclear power plants in order to maintain fuel diversity? I think the answer is pretty obvious. We would not.

We would have to address the question of how to build reliability into a system which relied heavily on gas, but also renewables, and clearly that can be done. Some of the ideas yesterday I agree with about how to deal with the gas infrastructure. Clearly, the gas industry is living in the last century, if not the one before that, in terms of business models, in terms of planning, in terms of interoperability. And if the grid were really going to rely much more heavily on gas, then all those issues have to adjust, but they can be addressed. And it's pretty clearly a lower cost option. So, let me stop there.

Question: Should I interpret this graph to mean that natural gas fired power plants in PJM are very profitable?

Speaker 1: Yes. But it is important to remember what we mean by profitability. So, this is a very specific definition. This is the retirement signal. So, "profitable," in this case, simply means you're covering your avoidable costs. It doesn't mean you're earning a return on capital. I have some other figures about that, but, interestingly, a brand new combined cycle, built with the technology then current in 2007, would in most zones actually not have covered all of its costs. In one Eastern zone, it's very, very close. But if you then advance out to 2012, and ask the same question about new combined cycles built with then current technology in 2012, the two Eastern zones actually are profitable in the full sense of recovering the expect return, even in some cases more than you'd expect to return, on and of capital.

Question: When you said they would not have covered their costs, you mean their avoidable costs, or entire return on --

Speaker1: What I was just saying about the units built in 2012, they clearly covered their avoidable costs, and it clearly made sense to invest in them and if you calculate what the implied rate of return is. It's not the target number, which I think we put in at a really remarkably high 15%. It was just something less than that. So, they in fact are profitable, just not as profitable as intended.

Whereas the numbers here are simply covering… think of these as being cash flow positive. There's no retirement signal, but they are not necessarily profitable in the sense of return on equity.

Questioner: Could I follow up on the question? When you say "avoidable costs," you mean the going forward costs that could be avoided by retirements? So these are not any sunk costs? This is truly fixed incremental costs of things?

Speaker 1: Yes. So, it's avoidable costs. When you say retirement, you just have to be careful with nuclear power plants, because of the whole issue about de-commission. But holding that complexity side.

Questioner: how do you know everyone's going forward costs to break it down by quartiles?

Speaker 1: First of all, we know them because we've been reviewing them in detail for people for the last 10 years, but in addition, in the case of nuclear, this is the first time we actually did nuclear, and rather than rely on individual unit confidential data for nuclear, we actually used Nuclear Energy Institute data, and they break it down by two types of plants. One is single unit plants, and one is two unit plants, and the avoidable costs for two unit plants are somewhat lower than single unit plants. So we relied on public data. In fact, anyone could reproduce that analysis of the nuclear power plant simply by knowing the location and the LMP, and by using those Nuclear Energy Institute data numbers.

Question: Was there anything unusual about the spot prices in that period relative to --

Speaker 1: Yeah, those were the lowest prices in the history of PJM.

Question: So, relative to the forward prices, you might have made more?

Speaker 1: I actually didn't compare the forward prices, because you're right. Clearly, the owners of most power plants sell their power forward, but we used yearly spot price actual net revenues. You're right. It could have been a little bit different if you looked at forward prices.

Speaker 2.

I think I was invited because, if it's a session about re-regulation, we have to have a Californian on the panel. Although, after reflection, there a different set of re-regulation issues in California, and if I have time I'll get to that.

What I was going to do is basically try to kind of frame of the issues. So the issues, as we all know, are, we've got these low energy prices, and they're posing serious financial challenges for many classes of incumbent generation. From an economic perspective, if it's just markets, it's just markets, but then the question is, are there some attributes to certain types of generation that are somehow providing value that's not currently being reflected in their revenues or reflected in market prices? Carbon is one answer to that question, one potential answer. There's also a lot of talking, in California, about flexibility in the face of a lot of intermittency. So, there may be some things that markets are missing.

Just sort of trying to pose as devil's advocate here about where some intervention maybe could be justified, it's worth noting that some of the generation that's struggling may actually be earning more revenue than they deserve, if we think about carbon as a price externality. And many states are either talking about or currently deploying a bunch of policies to try to indirectly or directly aid these resources, and that's sort of where the issues are, because these policies are almost certainly reflecting on regional market prices and impacting generation and neighboring states. So, that's what's going on.

The main issue, or one of the issues that everybody talks about, is, what are the drivers here? Obviously, natural gas and renewable energy are kind of the two things people point to. There's a lot of talk about zero marginal cost generation. Really, the fact that it's zero marginal cost is less relevant than the fact that it's before the other stuff in the merit order, but there is a fair amount of this new generation coming on.

Looking at some ongoing academic research, it appears that it does confirm my prior impression that natural gas is still the big driver in lower energy prices in the East. Renewables are starting to play a role, but not to the extent we've seen in California.

Here's a picture about California. We've been trying to disaggregate the differential impacts of things like gas prices, renewable penetration, and other aspects. What this is trying to capture is the effect of different layers of penetration of, in this case, solar energy in the California ISO market, over the period of about 2012 to 2015. Basically, what this is showing is the impact when you have a lot of solar, versus a relatively small amount of solar. In periods where there's a lot of solar penetration, prices are down about 10 dollars a megawatt hour during the biggest impacted periods and, of course, it's very differential over the times of day. So, in midday, there is a price reduction, and there's actually an increase in the early evening periods after the sun sets. That magnitude is about $10 a megawatt hour, which is about what was experienced from a dollar per MCF change in the natural gas price, but, of course, that's a much more uniform effect across the times of day.

So, yes, when you throw a lot of renewables in a system, it definitely does affect prices, but it affects them, not surprisingly, in a very non-uniform way. So, different types of generation are going to be faced with different challenges when they see a price profile like the one produced by high penetration of renewables.

So what's motivating these state subsidy policies? That then informs the question of whether we should do something about them. And you hear three main kinds of classes of intervention. Nobody says this is the motivation when they do them, but it sort of lurks in the background—the question of whether there's some aspect of buyer market power going on. Large net buyers (we've known this for a long time) can economically benefit from overpaying for marginal new generation if, as a consequence, it lowers the overall capacity price or energy price.

I'm going to offer a bunch of sort of academic economist solutions which will probably not be very helpful, and then at the end I'll offer some lawyerly advice, which is also not going to be very helpful, but…

We used to say capacity markets are a way of trying to deal with this sort of price discrimination and impacts on capacity, but we've seen that if you're a large buyer you can sort of figure out ways to take advantage of the fact that you're a large buyer pretty much in any market environment. And so, the ideal would be to not have individual load serving entities be able to dominate a market to the extent that they can influence prices. So that means less concentration, either via robust retail competition or basic generation service auctions, load slice auctions, whatever you want to call them, some way of subdividing of the dominant position of the load serving entity.

The challenge that we're seeing now is that when states allegedly act as if they are acting in the interests of all the load in their state, then it goes beyond just an individual market participant having a lot of load. The state is sort of acting as a proxy for all its load, and that sort of challenges the structural solution.

Environmental policies are certainly a big driver in a lot of places, like where I come from. And I think policy makers hadn't appreciated…when RPSes were first envisioned, I think they were sold as something like an auto standard. When you replace your car, we'll buy more efficient ones. When you buy a new generation, we'll buy cleaner generation for new investment. But as we ramped up the aggressiveness of portfolio standards and the timeline, we transitioned from, "The new stuff will be clean," to, "We're building new stuff even though we don't really need new stuff right now."

We're certainly seeing that in California, as we're moving more and more too displacing incumbent generation that is perfectly functional. And that does have a much quicker impact on carbon, but I think the policy community misunderstands the cost implications of throwing on extra capacity in a market that doesn't actually need new investment.

So, the best solution (Speaker 1 mentioned it) is, again, this sort of unhelpful academic economist solution. Let's price the externality. Let's throw a price on carbon, and then we'll know whether there is a real value that's being unearthed with the low carbon generation.

I do want to say that there are lots of different ways to do this, and they're not all the same. I've been working on the Clean Power Plan for two years, and to get something out of it I had to throw a slide into this talk, at least. [LAUGHTER] So, this is still kind of relevant to this discussion. We were looking at different ways of pricing carbon, since the Clean Power Plan articulated different options. We looked at thermal generation in the Western Interconnect without any environmental attributes priced in. We looked at what would happen if we took those same plants and adjusted them and sorted them in a merit order of all-in carbon costs, and we analyzed what the low-cost generation at the bottom end of the merit order would look like under a cap and trade system that would achieve the aggregate Western States Clean Power Plan goals. So, the gas gets moved in front of a bunch of coal plants in the merit order when you price the carbon in. Prices overall are higher, because that externality cost is reflected.

Then we also looked at what would happen under what was called the rate based standard on the Clean Power Plan, or you could think of it as what a market would look like if it was a sliding scale that gave benefits to any type of generation that was cleaner than the standard. What that effectively does is subsidize any generation that's cleaner than the marginal emissions rate that's the standard. So, for a bunch of gas plants, cost goes down. And that's because, under CPP, in many states, they would be able to generate profitable credits, because they're cleaner than the standard. The coal plants' costs go up. Overall, you still get this merit order switching, and the merit order, actually, in terms of the order of plants, is very similar under a cap and trade or under some kind of subsidy scheme. But the overall level of wholesale market prices is much lower. Because you don't have to tax the coal nearly as much to get the merit order to switch, if you're subsidizing the clean power at the same time.

Now, this was really important at one time. Because nuclear plants and incumbent nuclear plants weren't eligible for those types of subsidies. Only new incremental capacity would have been. And so, if you're a zero-carbon incumbent nuclear plant, a cap and trade system would be a very different economic situation than one in which only new incremental capacity was subsidized.

Which is all a long way of saying that we can come up with market-based environmental pricing mechanisms that still have some issues in terms of what they are transmitting through to wholesale markets, and certainly to retail prices. When states do it state by state, you get all sorts of scrambled egg types of merit orders. I don't have time to talk about that a lot.

So the last thing that's often sort of lurking behind the scenes, or maybe not so behind the scenes, is the fact that these subsidies are motivated by very important local impacts. Very large contributors to local taxes. For a nuclear plant, something like two thirds of the property taxes in a county could be coming from that nuclear plant, and these facts are very salient to the policy making community. It's almost certainly true that subsidizing out of market to keep plants around just because they create a lot of jobs locally is going to have a negative overall economic effect, but that negative effect is very diffused, relative to the very salient local impacts.

I don't have a great best solution to that. I was talking to some public finance people. This state support thing is nothing new. We've been through tax competition, luring large factory firms and headquarters and those sorts of things through tax credits for a long, long time, and the public finance community hasn't really figured out a great way to try to deal with it. There is some economic justification for this type of thing, at least from a state perspective, if you can argue that it's creating some kind of a conglomeration, what economists call a hub of innovation, or a bunch of ancillary activity around these investments, such that you do a pinpointed subsidy and it creates this sort of spillover effect. I think it's pretty hard to spin that kind of story for an incumbent power plant. In fact, I was looking for what the impacts of power plants look like, and there's a recent paper that's arguing that counties that had coal plants over the last 40 years have developed more slowly economically than comparable counties. The paper argues this is sort of the negative impact of the environmental and other sort of amenity benefits of counties that have large coal plants, versus those that didn't get them. Whether that translates to a current subsidy or not is sort of another issue.

So, to quickly talk about possible responses is to the policies, what the options are, the first thing that we've already seen is that, when it comes to direct intervention to either reject the subsidies through some type of regulatory or maybe legislative intervention, I think there are limits to this sort of tactic, although, when a subsidy takes the form of maybe an affiliate transaction or a very targeted subsidy, you can reject it under some kind of existing regulatory or market rule. However, there are probably more creative ways to create the same type of subsidy that the limits of this type of strategy will bump up against.

So, there's mitigation through ISO's, through things like minimum offer rules and other types of mitigation tools, and hopefully we'll have this discussion. The concern with all these sorts of things is the risk of exacerbating an original inefficiency. The fear is that if there's no way to stop this subsidy, and you're going to have this baseload generation in there no matter what, to run a capacity market in a way that would then spur additional investment in capacity, as if the capacity being subsidized wasn't there, is not the efficient answer. So, there is this key deterrence kind of question. If we have mitigation measures that prevent people from undertaking these types of subsidies, then there's a real dynamic efficiency argument for them. But if we think these things are going to happen no matter what, then the question is, do we just need to accommodate them and try to make the market as efficient as we can in the face of this? And that's sort of accepting that states are going to do what states are going to do, and we just have to sort of try to deal with it around the edges, and rate payers in neighboring states can enjoy the low energy that's being subsidized. The generation community doesn't like that.

I don't think this is a California story. California is encouraging the retirement of its baseload plants. We're certainly subsidizing a lot of renewable energy, but it is kind of market based. Certainly, we're not giving credit to zero emission nuclear. So, the big difference in California is that procurement is very highly regulated through the three dominant IOUs. This may change very soon ,though. So, we have a whole bunch of re-regulation in California, but I think it's a very different flavor than what Speaker 1 was sort of articulating as the end game here. So, I'll stop there.

Question: You said that California's encouraging retirement of its baseload fleet, and I don't disagree with that, but at the same time there appear to be new RFPs for new baseload resources.

Speaker 2: Yeah. We have a very almost integrated resource planning-style approach that's manageable because of the fact that we have kind of a moribund retail market. And I don't know if you could call that baseload. Most of the procurement is happening through the renewable channel, and then there's a lot of questions about how to manage the intermittency around that. But I think the big question we face is, if we do have a disaggregation of that load, and there's talk about retail competition coming back because of all the community choice aggregation activity that's going on, will we lose that aspect of the central procurement, and I'm not sure where that leaves us. So, that's the interesting question for us.

Question: I just want to follow up on a comment about how most of the renewable policies are relatively market based. Could you expand on that? Because the obvious example of one that's not is net metering, so I'm just wondering how they're market based.

Speaker 2: I was thinking about wholesale policies. So, yes, with net metering, there is a distortion that happens because of the rate making that is promoting the distributed solar (though it's not so much the net metering in California as the fact that the rates are just extremely high because of the increasing block structure). But the distributed solar is happening. I think there is even a larger impact of solar channeling through the wholesale market. But yeah, fair point. I guess I was referring to the wholesale market.

Questioner: I think it also depends how you define competitive too, right? One way of defining competitive is that utilities hold RFPs and they chose the lowest cost bidder. Another definition of competitive is you have a fully competitive wholesale market where folks are investing in renewables based on merchant economics and sort of bilateral contracting within the market, and I don't think the second one's going on. I think the first one is going on.

Question: I was puzzled on your slide where it shows the impact of different numbers of megawatts of solar on real-time prices. I was puzzled by, in the evening hours, why there would be a price difference resulting from different quantities of solar, when presumably there is zero solar being generated at those times.

Speaker 2: Excellent question and I wish I had a great answer for it. We're still trying to understand that ourselves, but the working sense is that it's a duck curve effect is that you have to run the rest of the generation in a different way in response to all of that heavy penetration of solar during the midday, and that is causing a sort of spillover effect into the hours even after the solar has gone off the system.

Speaker 3.

The main point of my presentation is going to be to take issue a little bit with something you said, Speaker 2, which is that the East is not California or not becoming California. And I would say the East could become California if steps aren't taken to mitigate the impact of out of market actions that are currently going on. And so, I'm actually going to spend two thirds of my time talking about what we've seen in California and the implication for our company and for other companies that build competitive generation, and what that means if it's moving east.

So, I'm going to start off my presentation with a quote which kind of underlies our thinking about this. It's something Acting FERC Chairman Cheryl LaFleur said, "When companies don't have confidence in their ability to recover cost through the market, they won't invest--potentially impacting the reliability and increasing cost customers." And the way we think about it is, we're only going to put our money to work in places where we think we can get a fair shake. And there are competitive markets in the US where that's still the case. That's where we are right now in New England, PJM, Texas, but there are other places, because of the fact they never opened up, or they've gone backwards, where we just won't invest any dollars without a long-term contract.

That brings us to California. I want to spend a few slides talking about California. I'm sure you'll recognize some of the faces on this slide. Upper left there is Governor Gray Davis sitting in front of the Sutter Energy Center, which is a Calpine plant. [LAUGHTER] And then Loretta Lynch, who I'm sure many of you know, remember as well.

So, a few key dates. Between 1998 and 2000, the market opened. Utilities divested. Significant investment in merchant generation begins. We had the 2000-2001 energy crisis. I had the picture of Sutter Energy Center, the first merchant plant come online in California during the crisis. At the bottom of the slide there, I note that we closed that plant last year due to economics. A 14-year-old, highly efficient, combined cycle plant. We closed it. And the reason why is everything that happened in between.

From about 2003 to 2006 was, this is my term, "the Golden Age of Peevey." He was a critical, controversial figure, but he was a very, very effective guy at getting things done. He explicitly adopted what he called the "hybrid" market, which is, "Well, we're still going to have competition, but we're also going to kind of pick and choose winners and losers, and we're going to tell the utilities they've got to procure, and they've got a rate base," and really central planning was re-established with discriminatory procurement, which meant that the utilities were going out for long-term contracts. Existing generators were left out in the cold, but new construction was getting $15 to $20 a kilowatt month under 20 year deals.

The era of Peevey ended in 2014, and then, like I said, sort of was bookended in California when the Sutter Energy Center closed.

So, their central resource planning process has guaranteed excess capacity. For conventional generation under 20 year contracts, there's been about 10,000 megawatts that's come online. There's ever-increasing renewable portfolio standards. There's a proposed new standard, passed by the Senate for 100% RPS by 2045. California has been highly successful in bringing on a lot of renewables, including (you talked about net entry metering) at least 5,000 megawatts of behind-the-meter solar due to generous rules there.

So, what has the result been? Significant excess reserve capacity. We're currently at about 140% of peak demand, and that's going to continue over the next several years. It drops down in 2020 to 121%, because of about 9500 megawatts or so of once-through cooled units that are going to have to shut down. But even after that roughly 10,000 MW of shutdowns, we're going to stay, for the foreseeable future, at a really comfortable reserve margin of 21%.

So, what has that done to all those megawatts that were built in response to the deregulation initiative in California? It's just completely annihilated the values. As I said, we shut down Sutter. Another plant La Paloma has declared bankruptcy, and you're surely likely to see more on the way.

One reason for that is that what you have in California is wildly divergent capacity payments. On the left-hand side of that chart is what existing generation gets under the resource adequacy construct which is California's capacity market. It's a bilateral capacity market. Prices range from about a dollar a kilowatt month if you're a system resource to maybe $2, or a little bit above, a kilowatt month if you're a local resource. And then you compare that to what the new resources are getting for providing the same capacity, it's like $13 to $24 dollars a kilowatt month or so. So there's a wide range of capacity prices that are being paid for in California.

So, no surprise, but the policies have left merchant generation financially challenged. And for three of our plants in the San Francisco Bay area, we calculated a cost of service-type number. These are all San Francisco Bay area combined cycle plants, probably about 2,000 megawatts worth of combined cycles. The going forward cost, or avoidable cost, that we calculated includes variable operating expenses and fixed operating expenses, including five years of major maintenance kind of spread out over the time. The sunk cost that we calculated is return on capital and return of capital. And we compared these costs with our expectations, going forward, but also looking back on the margin we are getting in the CAISO markets right now on energy, ancillary services and resource adequacy. So, if you look at the Delta plant, for example, our margin is not covering even going-forward costs. Same with Metcalf. Now, again, this includes major maintenance expenses which are like $25, $30 million every three to four years, depending on how much it runs. So, if you looked at it on an annual basis, there might be years where it's about breakeven, but then you've got like one year where you've got to spend $25 and $30 million. So, the question is, do you even spend that money, given the situation? You see Delta and Metcalf aren't quite covering going forward costs. Los Medanos is covering those costs, and that's really because it's a QF an it has a steam house, and we recover a couple million dollars a year in steam revenues from the steam house. That's the only reason that one's into the orange.

So, you say, "OK, there's been all this procurement and excess capacity. It's no surprise that these plants are in this position. Maybe they should just shut down." The problem is that each of these plants is becoming increasingly important for reliability. I mean, there are plants in California, certainly, that aren't going to be critical for reliability. Our Sutter was an example of that, and we just shut it down. We weren't looking for a handout. It wasn't needed. We just shut it down. But the CAISO reliability requirements indicate that it can barely meet its San Francisco Bay area requirement without those plants, and the gap grows larger over time. California's capacity mechanism doesn't really work in solving this problem. They do have the capacity market, their RA (resource adequacy) market. It's a fixed capacity requirement that each load serving entity has to meet, so it's like a vertical demand curve. It's like a one, zero. So, under oversupply conditions, prices crashed. If you get a contract, it's 80 cents to $2 per KW month, depending on whether you're in a good location or not.

But then in shortage conditions, which may arise in the San Francisco Bay area, RA prices aren't compensatory either. There's a softer RA price cap of $3.33 a kilowatt month and there's a bunch of back stop mechanisms. The ISO is not necessarily clear how those are going to be implemented.

So, however it ends up, whichever twists and turns we take, our view is that ultimately the only way to handle these units that are needed for reliability, given that they are not covering their costs and have major upcoming expenditures, is through RMR (reliability must run)-type cost of service agreements. So, sort of the net result is that you now have a market in California with tens of thousands of megawatts under long-term contracts or rate base. You have the merchant assets that aren't needed for reliability that are shutting down, and the merchant assets that are needed for reliability are at some point going to end up under RMR contracts. So, there's really nothing left in the market, sort of as a result intervention.

Our conclusion is that hybrid markets don't work. I mean, you can't, at the same time, expect a competitive market to work and be having the state picking winners and losers.

So, moving east. As opposed to California, market signals are still incentivizing merchant investment. In PJM new investment is coming online--14 gigawatts since 2010. There's new merchant generation still underway. I think 3,000 megawatts or something just cleared in the last auction. Retail competition is still active.

In ISO New England, new merchant gen is coming online this summer, I think the Footprint Plant is coming on soon. And then another two gigawatts is cleared and is in the queue as well to come online. And we still have retail competition.

But the storm clouds are brewing. This is sort of the topic du jour. New York and Illinois ZEC's, the Connecticut Millstone bailout… There's nascent Pennsylvania and New Jersey ZEC initiatives that are going on. In Ohio, there are the FE (First Energy) and AEP (American Electric Power) re-regulation initiatives. And then there's the Massachusetts Canadian Hydro and Offshore Wind Bill. These are all efforts or initiatives for state intervention into the competitive wholesale market that kind of threaten the success that we've had, or are continuing to have, in PJM and in New England with merchant entry and exit.

So our view is that it's time for policy makers to decide what world to live in. You can choose to live in a purely competitive world, which we've done for the last 15 years or 20 years, or you can choose to live in purely utility-centric planning world. We all know that one. We've done that for 100 years. But you can't do both.

To live in both worlds (and maybe it ultimately doesn't work, but I think we got to try) we need a mechanism to "wall off" the impact of state intervention in our wholesale markets. And that's really what's being discussed, and that's what the FERC technical conference was about. Alternatives include the expanded Minimum Offer Price Rule, which may be the best protection. There are two-tiered capacity markets, which PJM is talking about. There's ISO NE's "cash for clunkers" capacity market construct, which is kind of what they're talking about. There's also, maybe, pricing carbon as a solution, and maybe that's another solution.

But you need to put one of these in place, or else what ends up happening is you get to a point, and I don't know what that tipping point is, when you stop the flow of investment into the market, and states have no alternative but to force the utility or somebody to go and procure or to go and build something. And once you get down that path of telling someone how to procure or build something, then that starts to threaten retail competition, because the utilities have got to pass that cost onto someone through non-bypassable charges. You end up kind of threatening retail competition as well. So, this is a really critical issue that we got to solve right now.

Question: When you were comparing the prices for the new versus the future assets, was that apples to apples, or is that because there was like a reliability requirement that changed the price?

Speaker 3: That's a good question. It theoretically isn't apples to apples because the RA price is just a capacity payment, and then the generator keeps all of the energy market revenues, whereas the long-term contracts are generally tolling agreements, so all of the value of the energy goes to the utility who's tolling the contract. But it turns out that the energy value associated with those tolling agreements is so close to zero that even though in theory they're not apples to apples, in reality they become apples to apples, because there's no offset to the full $13 per kilowatt month capacity price.

Speaker 4.

I'm happy to be here. The way I think about this question is it's kind of like a puzzle that I remember from college. Now, there's a Buddhist Monastery and there are 150 monks, of which 50 of them actually have a disease. And one night the doctor comes and puts a mark on everybody's forehead when they're sleeping, and the monks are not allowed to talk to each other. And if a monk finds out he or she has a mark on their forehead, they will leave the monastery so that the disease doesn't spread.

The question is, how many days will it take for all the monks to figure out that they actually have a mark on their forehead.

And that's, sadly, like some of the issues that are going on in the markets. Because there are generators that are not covering their cash flows, or that are not able to provide an adequate return. And that I kind of equate to monks who actually have a mark on their forehead. And there are the ones that are profitable, who don't have a mark on their forehead, but they don't know how long the monks who have the disease will last. And if you go through the puzzle, by deduction, everybody figures out, on the nth day that they have a mark on their forehead, and they leave the monastery. But it takes n days to figure that out. And, sadly, in the PJM space, and the generation space, that's exactly what's going on. Nobody wants to admit that they actually have a dot on their forehead, and they're waiting for somebody else to leave the market. And that, in my opinion, is the crux of the problem. And on top of that, we have the state intervention issues, which I don't know that you can avoid. And that summarizes the problem with competitive markets, where someone might decide competitive markets are not the place to be.

So, from our point of view, historically, at least, the baseload units, coal and nuclear units, even though they had capacity clearing prices, they covered their margin, and that's no longer the case. There's a lack of financial support for coal or nuclear. In some cases they're able to recover their avoidable costs, but they're certainly not making any rate of return that the investors want.

Here's what is called the ISO/RTO future generation mix. I think one thing that is illustrating is that none of the future generation mix, at least what has been planned, has any significant nuclear retirements on the horizon. At least I haven't seen any transmission planning scenarios where they actually assume nuclear plants to be retired either in SPP, MISO, and certainly in PJM. So, that obviously raises an issue in terms of, what are the downstream implications of either significant coal or nuclear retirements on other costs that are being imposed on the system, primarily transmission operations, and that is lost in the conversation if we purely talk about the competitive market perspective.

This slide pretty much says that in these market conditions, the only plant that is going to enter is a combined cycle plant, or a gas plant, given that the coal and nuclear plants are completely out of the money in terms of new investment, base on the levelized cost and where the markets are going forward.

On this slide, we kind of went back and looked at what was the credit rating profile of the PJM generators, looking 10 years back. And we looked at the top ten power generation owners in PJM. If you look at that, back in 2006 you had close to 89% of the generation which was investment grade, and the remaining 11% was by non-investment grade owners. And certainly that has significantly deteriorated. If you look at the percent now (and obviously in PJM this actually includes AEP and Dominion, which actually is decently regulated, so if you take that number out it even skews even more) the non-investment grade generation 44%, and 56% is the investment grade entities in PJM. And, as I said, if you take out the AP and Dominion generation mix, which is close to 35 gigawatts, that number gets even more skewed. So, the question obviously is, can you rely on a generation mix that is financially unstable?

We have seen a trend, at least for traditional investors who are primarily affiliates of utilities that own competitive generation, which is that they are unable to weather the storm. So what we have seen is a significant entry of private equity into this space, which can take a much longer view, as opposed to the financial investors of the IOUs or the publicly traded companies, which want immediate results. And that has been a trend that you see in PJM, where most of the assets that have been procured are either by private equity owners or by entities that have a longer-term view on these markets and can weather the storm much better than the investment grade utilities or IOUs.

On the topic of state intervention, we think the state intervention is actually happening because they actually have a different view on what the generation mix should look like, or what capacity markets should look like, a view that is a little different from what PJM sees. It could be for policy reasons in terms of saving jobs, or it could be that they want a much smoother transition, in terms of getting away from coal or nuclear to other forms of resources, it could be multiple reasons. And we've seen some of that in Ohio, and now you see that in multiple places, in Illinois, and potentially in Pennsylvania and New Jersey.

Right now, the PJM capacity market is the lowest cost short term capacity market. It doesn't really tell you what the total cost of ownership of these assets are through the lifecycle, and that is an issue. And I know we talk about resource diversity and resiliency, and that that is in the eye of the beholder, and the state regulators do have a view on what that should look like, and that is certainly not being reflected in the PJM space.

What measures should we do? I might be taking a little different approach than what Speaker 3 was suggesting. We think PJM at some point is going to go towards more of a bilateral market space. States will start demanding that entities enter into long term bilateral contracts, because that's how they will satisfy their resource diversity obligations, or whatever preference the states do have. Either through a subsidy or by specifically mandating the load serving entities to enter into bilateral contracts, we think at some point that is inevitable. And there are multiple reasons. One is because they can tailor the bilateral contract in a much more unique manner on a state by state basis, as opposed to relying on a pure PJM market construct. And, second, it is still competitive. It can still meet the FERC issues in terms of meeting those obligations.

If you look at PPAs, they are pretty prevalent in most of the ISOs and RTOs. Even in PJM, fossil PPAs are close to 11.9 gigawatts. So, most of the gas plants that are being built, I'm assuming, are falling into the PPA. So, that is a reason why gas is being built in PJM--not just because it's profitable in the short term, but because they also able to enter into the long-term contracts. And, similarly, that is what we have seen as a trend in other regions, including ERCOT and MISO and other places where PPAs are much more prevalent and common than in PJM.

The last comment I will make is that, if you go under the assumption that states at some point will start imposing mandates on the load serving entities in terms of entering into these contracts, how does that affect capacity markets? We think at some point the PJM RTO will primarily be in the resource adequacy role, not deciding on what kind of resources will be participating in competitive markets, and effectively, at some point, become more of a bilateral scheme, similar to what California is. And we think that is inevitable if the states do want to take a role on this issue.

Moderator: Does anybody on this panel want to comment, before we start the discussion?

Comment 1: I think the idea that bilateral markets can be as competitive or transparent as a central clearing market is clearly wrong, demonstrated to be wrong, but it's also the case that bilateral transactions of course occur within markets all the time. In PJM, there are lots of bilateral contracts, as was just pointed out. Probably most gas-fired combined cycles that are built have some form of off take agreement. It's a private bilateral contract. It helps finance it. That's entirely consistent with markets. Markets are the benchmark for what the competitive price is. If you do bilateral contracting, we've seen where states can get, with bilateral contracting, to the same kind of place they get with long term planning. They always make the right decisions, as we know. [LAUGHTER] So, I mean, there's a reason that Enron wanted a bilateral market in California, and it wasn't for transparency, and it wasn't for competitive outcomes. So, it seems to me that the notion that states will be running bilateral markets, it certainly could occur. The states have the authority to do that, but the idea that it is even close to being as effective, efficient, or competitive as an actual market is, I think wrong.

Comment 2: Look, Calpine has probably a half dozen or more people whose sole job is originating bilateral contracts with counterparties. And it's true that a lot of the new development in PJM or New England is based off of bilateral contracts, but I'd call those hedges between two competitive counterparties. A lot of stuff is being financed with five developers, is financing for a plant with a five year, a ten-year hedge with a bank or something like that to basically mitigate its price risk for some period of time. Now, the bank is not bearing that risk, and it goes out and it tries to manage that. And that's fine. We talk to anybody, anytime, about doing that kind of bilateral transaction, and that's what makes the market work. What we are concerned about is when you have a state mandated RFP process where they say, "Utility, we don't like what PJM [let's just take an example] is doing. You need to go get this type of plant, and instead of paying the market price which is $150 megawatt day, you got to buy a new plant for a 20-year contract at $750 megawatt day," or whatever the number is. Which is essentially how California works, from that chart that I showed, where the existing folks are getting capacity prices based on a dollar to $2 in the bilateral market, but new stuff is coming online at $14 to $25 through the state mandate. And that's the problem.

Speaker 4: I'm not questioning the differences between new and existing bilateral markets in California. But I think if new and existing resources can both participate in an equal manner, then the bilateral markets will work, and then you'll have a better longer term price signal that the generators can take advantage of to the extent they're successful. If not, you certainly have the backup in the PJM space to plan a shorter-term market. And that is what we see at some point as a solution to this issue. Otherwise, you're going to be debating about whether states can play a role, or where the role ends and where it begins. So, I think that is our solution. I'm in no way proposing a market where new versus existing resources get treated differently. It's all resources can get to play in the space and provide the necessary long term price signal that companies want.

Commenter 1: But you're assuming that this bilateral construct can coexist with a market, and it simply cannot. And that's what the Maryland and New Jersey cases stood for, but the economics show that you can't just have these state bilateral things and then have the market working perfectly as a backup. It can't work that way.

General discussion.

Question 1: Speaker 1 gave the statistic that a combined cycle that was built in 2007 may not recover its costs the way combined cycle built in 2012 recovers its costs. And my question is, we are seeing technology advances, particularly on the gas side, but in solar, when you think about what solar panels cost five, 10 years ago. We're blaming subsidies, which have always been around in one form or another, for cost recovery problems. But is really the problem that the technology is cannibalizing itself, and that for these investments that used to be made for 20, 30, 40 years, the technology is now becoming obsolete in five to 10 years, and uneconomic, and is that really what is going to undermine these markets, as much as a subsidy?

Respondent 1: I prefer the term "competition," rather than "cannibalization." Otherwise, I agree.

Respondent 2: I think there are a couple of things going on. One is, if the gas price dynamic is durable, then there is a bit of making technology obsolete going on, and maybe that couldn't have been foreseen at the time these things were built. But another factor is the strong push from federal and state policies on renewables. If we prioritize carbon emissions reductions, then you could say some technologies are becoming obsolete because of some attribute. Now, how nuclear fits into that is more of a complicated issue, because they're being made obsolete, even though they are zero carbon. But you can't ignore the fact that we have this other environmental overarching goal that's a big driver.

Respondent 1: Can I just feel sad, from our perspective? I mean, call us stupid, I don't know, but that's the business that we chose to be in, right? If we invest in a plant and something comes along down the road that is, instead of a 7,000 heat rate, a 6200 heat rate, or a 5800 heat rate, or is a different technology, or whatever, that is the market, and that is what we signed up for. What we didn't sign up for is when it comes down the road and its being given a huge check from whatever the state regulator is, when it's basically competing with us. And so, to us, that's kind of the distinction.

Question 2: This is really a clarifying question for Speaker 4. I was a little unclear. You indicated you thought that, at least in the PJM space, there'd be a migration to bilateral contracting. My question is, who are the counterparties? Is it the default provider, or is it load serving entities generally? If it's the latter, how do you square the fact that they, or at least competitor suppliers generally, have one year contracts with their customer? Often shorter. How does that provide the state with the warm and fuzzy resource adequacy assurance, putting aside the fact that I think that's an illusory worry, in a sense. I didn't quite understand how you thought that was going to occur.

Respondent 1: I was more under the impression that it will be done with the default service provider, not by the LLCs. The state would effectively mandate the wires entity, similarly to California in some ways --

Questioner: So, the wires, they're buying power for customers they don't have, and then they pass it along to all the --

Respondent 1: At some point, there'll be some legislative change, but if the state wants to take control of, not resource adequacy, but resource diversity issues, at this point, they will have to effectively ask the wires company to do the long term procurement, or actually, they can have the port authority or any other entity to do that in order to make that happen. Is that possible? I don't know. It depends on what state's priorities are in terms of making that happen.

Respondent 2: Just to clarify, in California, it is not the wires company. We haven't gotten there yet, except for some reliability-related interventions, but it only works because of the cordoning off retail competition, and the procurement is done, basically for the default, and the default customers can't migrate. But now, in the face of community choice aggregation, we're going to challenge the viability of that, because there may be an overhang of stranded assets from that model.

Respondent 3: But your question does raise an important issue about the interaction between retail and wholesale competition, and your point is exactly right. There really aren't counterparties, because at most you have a three-year contract to serve load. No one's in it, except for public power, and nobody's in it for the long term, therefore there really isn't a counterparty for a long-term bilateral generation contract.

Question 3: I was tempted to follow up on this by noting that Jeff Skilling is going to be looking for a job pretty soon. [LAUGHTER]

And he has a lot of experience with designing bilateral markets. [LAUGHTER]

But what I want to do is ask the panel to comment on what we heard yesterday morning in the discussion about cutting edge technologies, all those things that are going to happen on distributed energy resources, the complete change in the mix, all the things that customers are going to be doing out there on their own, and we're not going to be able to stop them. It seems to me completely inconsistent with the story we just heard about how we can't have competitive markets, and we have to have long term purchase power agreements that are regulated by an entity which could offer…this is *deja vu* California in 1990 all over again. Things like the six-cent law in New York, and so forth, where we had long-term purchased power agreements to pay a lot of money for stuff that nobody's going to want to buy, when we actually get down into it, because they're going to leave by providing their own service.

Respondent 1: I think markets facilitate all the kinds of creative notions we heard about on the first panel. Just as one example, if you had more effective retail competition, the wholesale power market could easily address and flexibly address customers' ability to avoid paying for capacity. As an example, if we're paying for energy during high priced periods, one of our long-term points about the PJM market is that the demand side should actually not be constrained by the capacity market. Rules should be such that all the kinds of flexibility and creative actions by customers that were talked about on that first panel could actually happen. So, in my view, markets make that kind of flexibility possible, and bilateral contracts are doing the opposite. They're locking customers into unavoidable long-term costs and there's no return for creative solutions, and no incentive to be creative.

Respondent 2: It seems like distributed technology gives one more way in which a customer can migrate away from some kind of long-term commitment, or just leave. I think there are still questions about exactly where the economics fall on that. As was just suggested, the next phase may be that some of these costs will be shifted to non-bypassable distribution-level fees, and that's where the distributed technologies come in, to the extent that we're putting on a lot of distributed resources just to avoid fees that we've layered onto distributed charges, then we're getting into a dynamic that's pretty worrisome. But I had to go in a seminar so I missed the panel yesterday. So, how close we are to that actually being a major reality, I think, is still in play.

Respondent 3: If you believe states will interfere and actually successfully intervene in the wholesale market, then where does this take us? Is that projection contrary to the session panel yesterday? Yes. There is no doubt about it, because, effectively, you can't have market-based resources come into place and have the market signals being destroyed by some state intervention. They do kind of go against each other, so the only thing that we are trying to address in this session is, if states are successful in interfering in the markets, where do we see the next options in the decision-making role?

Question 4: Good morning everyone. I kind of wanted to make a comment, and it is based on some of the things that were discussed yesterday and today. We in Arizona are in a vertically-integrated market, so we don't have many of these issues to deal with, although we have been discussing the possibility of forming a regional ISO with California ISO for about the last year.

From a regulator's standpoint, I tend to look at this from the point of view of there are some very wrong answers, but there aren't any real clear right answers. When you look at it like a mathematics problem, there's a right answer. But in looking at these factors that we're talking about, in terms of markets and subsidies and what we're looking at happening with nuclear and coal in the United States, there are a lot of wrong answers. And, as a regulator, I try to look at things through the lens of, is the network, is the grid, going to be secure? Is electricity going to be affordable? Is it going to be reliable? Is the grid going to be resilient? So, when I look at what things are happening, I look at it from the lens of, how do we make sure that we meet that core objective of reliability, resilience, security, affordability, so that we don't have problems?

And the other thing I would observe is that a lot of the regulators out there are grappling with something that is at a much lower level. Some of the folks in our part of the world are trying to figure out three-part rates. And when you start looking at all these other factors that the market introduces, we have a very difficult problem, in that we want to do some things that will encourage innovation. We want to do things that are going to encourage investment in the grid, so we can provide some of these new services that customers want, and support some of these new technologies, and support great levels of security.

But the question that I would ask of the panelists is, what should we be doing as regulators to try to move in some of these directions, understanding the mission that we have, which is that mission of ensuring the security and the reliability and resilience and affordability of things?

Respondent 1: Far be it from me to tell a state regulator what to do. I actually worked at state regulatory commissions so I know something about that side of it, but what I would say is, I think the right answer is that you have to make a choice between whether you're trying to direct and choose all those things, or whether you're trying to set up a market, or a system, and I would call it a market, which provides incentives for and returns for innovative behavior. I think the lesson is pretty clear that a market that gives incentives to a large variety of diverse players to do creative things is more likely to get anywhere you want to be than telling people, "This is a good technology," or, "That's a good technology."

Now, markets are far from perfect. We need to continue to improve them. We heard from the panel yesterday about some of the flaws, some of the areas that need to be improved, to provide those incentives, to let participants be more creative. But, again, I think it's pretty clear, at least from my perspective, that a market with decentralized incentives is the way to go, rather than directing this technology or that technology.

Respondent 2: Maybe to latch onto Respondent 1's issue, I think the state regulator has to make a decision whether, in the case of PJM states, whether you want to give up the resource adequacy and everything else to the PJM, or do you want to retain some of that under the state umbrella? I think, now, if you talk to anybody in Ohio, even an industrial customer in Ohio, they would say, "Once we move to PJM, and once the state is deregulated, all the aspects of reliability and grid resilience and all of that is a PJM issue, it's not a state regulator issue." And whether the states can come to that realization, or whether they want to make changes to that is the final question.

Respondent 3: I think we're all sort of saying similar things. There is this tradeoff of states recognizing the value of regional cooperation and regional markets against what is at least the perception of being able to drive policy locally. And it seems that a lot of the issues we've been discussing come down to different states having different policy priorities, to some extent, and if we can reconcile those into a more regionally consistent approach to a bunch of these different sets of issues, then I think there isn't nearly as stark of a tradeoff. One of the problems that we're seeing is that trying to have these state priorities transmitted through these very tightly integrated regional markets is creating this disruption. Cutting off the regional market is not the right answer. The better approach is to try and smooth or reconcile those state-level priorities, to some extent.

Respondent 4: I think there is a qualitative difference in how you define a regional market in the West--California and Arizona and other states that may be joining with CAISO. For example, take PJM. In New England, where there's a regional organization where most of the states in the East have retail access and they rely on market signals, for the most part, to get generator entry and exit, all of these rules about mitigation, et cetera, are very important, if you want to keep the price signals in place to get merchant investment, et cetera. But if you move to the West, where all the states are fundamentally integrated, and you're talking about creating an RTO, or about the expansion of CAISO, that in my mind is really just sort of expanding an efficient dispatch mechanism. I mean it's not being looked on to send the price signals to get new generation built or new technologies put in place. State regulators are still going to do that in the West, and so, I don't think these sets of issues that we're talking about are quite as important in that scenario.

Question 5: We've heard the theory, which I agree with, that you can't have a competitive market coexist with massive subsidization and administrative entry. But what's the ultimate breaking point that forces the people in a position of authority at FERC, or at the states, or at the courts, to actually make a clear decision on any of this? Because right now, all I perceive is a lot of ad hoc disputes, and no one who's actually in a position to decide whether to go full Hogan or full Speaker 1 or full Speaker 4 seems to be poised to do so. Everyone seems to be still dithering around, and I guess what I see in terms of energy policy from the putative leaders, like those in California, is just a hodgepodge. I mean, not only are we going to have a cap and trade system, which really should be all you need in order to deal with your climate problem, but we're also going to have a 100% renewable standard. And then we're going to have an IRP that tries to put its fingers on all these hard to get externalities, but not before we have the storage mandate and also the energy efficiency mandate. And, eventually, I think you will get to the point that Speaker 2 and one of the earlier questioners talked about, where you have customers trying to bypass those things that are being imposed through public policy. I mean, we saw in the past iteration of restructuring in the West, that industrial customers, for instance, can only tolerate this for so long before they use their own political power to try to cut themselves a deal and get out from under those charges. And we're seeing that now, with the casinos in Nevada, and Microsoft in the Northwest, and customers and community choice aggregators, maybe, in California. And usually it's dressed up in the valance of, "Well, we can do green better than you can." But at some point someone's left holding the bag.

So I come back to the original question, where do the panelists see openings for people to actually make a clear policy decision that can maybe stop the hodgepodge?

Respondent 1: The courts. [LAUGHTER]

Respondent 2: When Cheryl LaFleur talked about what the options were, she said she didn't want to go down the litigation path, but it seems to me that the litigation path is entirely unavoidable, and if FERC doesn't want to draw the line the courts will. The line is a little bit fuzzy, but I think you can state it as, when the states take actions that impact or significantly impact wholesale prices, that's over the line. New Jersey, Maryland, Ohio, some of the Ohio decisions that FERC made or that FERC is facing this year are judicial decisions, I think former Commissioner Clark and Commissioner LaFleur have said something like that. I agree, they haven't totally drawn the line, and have talked a little bit about trying to accommodate, rather than actually having a line.

But, while the line is not absolutely clear, and this gets a little bit fuzzy with some of the subsidies, I think that is a way to describe it. I hate to go back to the "You know it when you see it" pornography standard, but in a way that is what it is.

Respondent 3: I can now give my unhelpful legal advice. I'm not a lawyer, so you don't need to pay attention. I think one way to articulate the line is that actions that are taken to affect prices clearly are crossing that line. But the elephant in the room is always going to be environmentally-focused policies which are also going to be affecting wholesale market prices, and people don't want to cross that line, at least in the regulatory legal arena. There is maybe some rationale to that, and it sort of goes back to this question of whether the interventions are actually being made with the intent to affect market prices. In that case, then not allowing them to affect market prices should deter it. If they're being made for other sorts of state value reasons, then it's not clear that actions at an ISO level that make it less financially rewarding or take away some of the financial rewards would actually prevent those types of arrangements, anyway. And then you're in the arena of thinking about the best way to deal with the fact that some state policies are going to probably be driven one way or the other.

Respondent 4: I don't know. It feels as if we kind of started the whole thing with the state RPSes. That had direct impact on the wholesale market, but some of you are comfortable with that. And now, when there is interference because of coal or nuclear, that seems to be a clear no-no. So, how did the federal level of oversight become comfortable with state RPSes? And now, we're not comfortable with states taking additional actions, through ZECs, etc.

Respondent 3: I think that litigation is probably going to have some impact. And LaFleur started with the technical conference last month. And I don't know that there's going to be a national solution. It may be regional, and it may be different for each of the regions. The good news, from our perspective, is that both ISO New England and PJM are really showing some leadership, they have been developing proposals, whether you liked the proposals or not, on how to address this issue. And I think both are serious about filing something at FERC to address this issue. They're both in the process now, and I'd probably say later this year into early next year, you're going to see filings from both those entities, and then it will be up to the two new commissioners, and to the new FERC.

Question 6: States see carbon goals as important, and as the missing part of public policy, and they say these carbon-emitting assets wouldn't retire for a carbon price of a certain amount, so they're going to intervene. That seems to me to be a legitimate goal of states. I guess I would ask Speaker 2 what, if those policies are impacting prices, and the company that is getting the subsidy is also benefitting, with the rest of their portfolio, from the withdrawal of those units from the market, where does the public policy balance lie there, in terms of whether the prices should be supported at the higher level, when it might look exactly like what they wanted to do if they were trying to exercise market power?

Respondent 1: This becomes a lot cleaner if we just put a carbon price on, rather than trying to do things from the subsidy direction. So, referring to what you're describing, my question is, what if the subsidies are also benefitting a, say, net buyer-type entity that also happens to benefit from the low energy prices?

So you are asking about a large generator, say, which gets a high capacity price because the subsidy's taken the other unit out. That's an example of a problematic outcome. I think that's something that we should really be concerned about if it is leading to too much or the wrong types of capacity. Sometimes entities are going to benefit, but it doesn't actually change the outcome. And that's less of a focus then if it's actually changing the market outcome.

What if California had 100 percent RPS, but it allowed RECs from the entire country? Then California would be actually affecting prices in

PJM, and wherever. And there are limits on what these regulatory tools can do. What if Europe started buying offsets in the U.S.? So, I think there are limits on what even state policy tool interventions are going to do. there is some aspect in which values are going to affect market prices.

Respondent 2: For every state that values carbon and says, "If not for the lack of a carbon price, these nuclear plants would have stayed alive, or would be positive cash flow," there are other states that will say, "If not for RPS resources, the coal plants would have been alive, and they would be sustainable." I think that's where the issue is. So, I think it's very easy to see one side saying, "I'm going to focus on the states that value carbon," but there are equal numbers of states that don't value carbon, and they actually see the subsidies as the reason why the coal plants are not surviving.

Respondent 3: Sometimes subsidies are really the result of intensive lobbying by particular companies about particular units. So, they become state policy, but that's not really their genesis, so it's important to keep that in mind when you're thinking about state policies.

Second, I would not agree with your assertion that it's OK to intervene in the market as long as you have a good plan—say, for example, to reduce carbon output. If the states in PJM can agree, which I think logically they could, on a carbon price, then I think a carbon price could exist across a footprint. But you can't do carbon intervention one state at a time and one unit at a time. It simply doesn't work with the market.

Question 7: I want to pose a hypothetical to you, which I think is particularly relevant for areas that are thinking about more aggressive carbon goals. I want you to imagine an RPS, except we're going to add nukes and kind of set that issue off to the side. And I'm interested in what the panelists think about two approaches to that. One, an RPS with nukes that just relies on a price signal, recognizing that there are a number of different things that a an RPS will not do efficiently as compared to a carbon price. And compare that to the way I think it's being rolled out in California, and how it's being rolled out, largely, or it seems to be headed that way, in New England, where instead of relying upon the price signal, we do procurements and do multiyear contracts.

But let's imagine that at the end of the day, at the end of the two paths, you end up with more less the same mix. You have to meet the RPS standard at the end. It's just that how you get there is a little different. I'm just interested in the panelists' views about this, because, to me, it kind of puts the focus on this difference between a market price signal versus this procurement approach and what might be some of the benefits or pitfalls of the two.

Respondent 1: I don't necessarily agree that your first scenario, to the extent I fully understand it, is a market price signal. I think there's a difference between identifying a specific subset of technologies or units and saying, "We want to procure X amount of that," and saying, "The objective is carbon reduction and we want to put on price on carbon and get the most cost-effective carbon reductions," whether that's an expended RGGI or a California AB 32 or whatever, or a generation-wide carbon price. And that seems to me the most cost efficient way, and a true market priced way, of getting that objective achieved.

Respondent 2: I couldn't agree more, but recognizing that the world where we actually get a carbon price is pretty remote at this point, whereas the RPS world, I think, is at least within the realm of plausibility.

Respondent 1: I guess I would just disagree that that is a real market-based approach.

Respondent 2: I guess the way I think of it is, you could start with just a cap on carbon and put all the options on the table for trying to get to that goal. It could be that having nuclear and renewable electricity is the least-cost way of getting to that goal, in which case doing it through an RPS is more or less costless, because you're doing the same stuff anyway.

The problems arise when the percentages are off, or there are other options out there. Maybe its gas, coal to gas, or maybe it's something outside of even electricity, and basically, when we start slicing different parts of the economy and running even little mini environmental markets within them, we're losing the ability to arbitrage options from one sector to another, or from one set of solutions to the other. And so, how bad that problem is kind of depends upon where we end up. But I guess we need to recognize that we don't know what the right answer is, and so that's the whole point of having as flexible a market-based approach as we can—so we don't get stuck with the wrong answer.

Respondent 3: Of course RPS standards are a form of subsidy. Of course FERC needs to reconsider their choice of a few years ago. It's not the case that it's not jurisdictional because it doesn't have any effect on markets. Clearly, it does. Subsidies are subsidies. And that's a short way of answering the question as well, but whether you include nuclear in your RPS or not, it is going to significantly affect prices.

Question 8: My question is about fuel diversity. Let's just take it as a given that that's a worthy objective of markets. What can market operators do to get to that objective and avoid out-of-market subsidies?

Respondent 1: I'm sorry not to take your direction very well, but I have a hard time accepting that as a given, just because, I mean, the question is, what's the goal? I mean shouldn't the goal be fuel security? I have lots of different kinds of fuels. Would we build uneconomic nuclear power plants now just to have fuel diversity, or is the goal to have fuel security? If it's the latter, and let's just say we hypothetically only had gas, then we'd have to figure out a way to deal with it. I think we can deal with it. There are lots of things to do to make the fuel supply reliable, and, to go back to the question from Arizona, of course that's one of the goals of the RTOs and the ISOs--to make sure that power is reliable and is as cheap as possible, given the constraints. So, I don't think it's a legitimate goal of the RTO to have a particular mix. And I think the RTOs need to resist the temptation to put weird constraints in a capacity market to produce a particular mix. The idea us to have the least-cost set of power plants, but they have to be reliable, and those issues about reliability have to be addressed, particularly with regard to the gas supply. So, I, again, apologize for not accepting your assumption.

Respondent 2: I can't speak for the other RTOs, because I'm not sure exactly what they would have done, but both PJM and ISO New England have tried to address this issue, post-polar vortex. In PJM, with the CP, the capacity performance requirements, and then in New England it's PFP, pay for performance. And really the driver of those initiatives was to basically really punish generators that are not there when they're called on. And I think some would argue that those programs are not as effective as they could be, and I think that's because they need to change some of the inputs. They can make penalties higher and change some of the other input assumptions, so that there really is a real penalty for nonperformance. For example, for our fleet in the mid-Atlantic, we have backup oil on all our plants as a result of CP. We had one plant that didn't have it, but we've since installed it, because of fear of penalties, and if CP is not creating the response that PJM wants, I'd say they need to get a little bit more tougher with the penalties.

Respondent 3: Is your objective function to minimize the total cost, or are you objectively trying to minimize volatility of prices? That could give two different answers, depending on what your objective for fuel diversity is. Another thing to keep in mind is that once you retire nuclear plant, it's not coming back anytime soon. It takes 10 years to build it, whereas a gas plant is much more flexible to build and operate. And so there are some nuances to it. I don't know if the market captures those nuances effectively or not today, It's debatable.

Question 9: I wanted to pick up on Question 5 and try to drill down on one aspect of it, because I agree with Speaker 3 that we can't be half pregnant on these markets. Litigation appears to be the clearest way to provide clarity there, but that litigation path takes years and it is not a given that we will get clarity out of it, as we saw from the Hughes decision.

So, Question 5 highlighted the fact that one of the main influential groups in all this, and actually the group that probably had the biggest hand in pushing restructuring in the first place, was some of the C&I customers screaming about some of the cost increases that they were seeing under the previous model. Are we going to have to wait for some of these subsidized resources to hit that market, drive up some of those prices, and try and muddle our way through with some of the interim plans like the CASPR (Competitive Auctions with Subsidized Policy Resources) proposal in ISO New England and others, to buy some time to get there, or not?

Respondent 1: We can't afford to wait. If we allow these programs to go forward, the markets are going to be damaged in significant ways. If we have to, we have to. That's the way reality works out. That's the way it works out, but I'm hoping that the combination of the Commission and the ISOs and RTOs will resist actually having to force the issue, so we don't have to have a bad outcome and have to reverse it. So, my hopeful answer is no.

Respondent 2: I'm curious as to how much certainty a rejection of the current set of proposals would actually provide, or whether it just sort of forces activity into more subtle forms of subsidies. And it seems like a creative policy maker could come up with ways to try and meet whatever sort of standards are set, but sort of achieve the same goals.

So, I do think that at some point if these types of proposals become costly enough for an individual state, which is in effect subsidizing consumers in neighboring states, so that there's pressure there that eventually, I think, leads to push back. I don't know where that point is, and it's certainly different for each state, which still leaves us with sort of an asymmetric outcome, as far as a regional market goes.

Respondent 3: Most of the proposals have tried to isolate that effect on that state only, at least up at the PJM, the proposals that have been floated. But it's kind of difficult to isolate the entire effect on that state only. Because let's talk about now what are the new congestion profiles looks like, what transmission gets built after, as a result of these differences between states with carbon policies and states without carbon policies, or states with ZECs and without ZECs. Now who pays for that transmission line, because it's relieving congestion that is being created as a result of artificial price signals?

It kind of goes off on multiple layers, and the entities that are complaining because of the impacts may not be the C&I customers in the states with carbon policies who are seeing higher price spikes. It could be in the other states that have no carbon policies, where there are additional costs, or there's a perception of additional costs because of other effects that are being put as a result of these artificial price signals that are being incorporated into the market.

So, impacts could take multiple forms, and there are certainly more, price sensitive customers in the Midwest, because our profile is a lot more industrial and commercial, because of the historical presence they have. And their price sensitivity is so much, because a penny or two makes a huge difference in terms of their sustainability, especially when you're talking aluminum smelters or cement and all those industries. And that is huge impact, versus in the East Coast the industrial mix is a lot different and the price sensitivities are different. So I think you've got to be conscious about the more price sensitive industrial customers, which are predominately in the western part of PJM.

Respondent 1: And, you know, in court we're fighting the nuke subsidies, and we've gotten very good response from the industrial customer coalitions. Look, PJM and ISO New England wholesale prices are at historic lows. And it is kind of difficult to get a lot of attention when prices are that low right now. If all this comes to fruition and comes to pass, that might change, but right now, with prices where they've never been so low before, it's hard to get the attention.

Question 10: It's good to have a new perspective, since a lot of us have debated a lot of these issues. I'm wondering, mostly from a renewables perspective, if sometimes the cures aren't worse than the disease, or at least if there are ways to avoid unintended consequences. The PJM and other proposals on this state policy and organized markets topic are relatively new, so I don't know that they've really been critically examined yet. And they already arguably exclude renewable energy and storage, or at least no longer take into account that capacity value, so they don't allow us to participate. On the repricing proposal amounts to, effectively, intentionally raises the capacity price, and isn't that going to have the predictable effect of attracting inefficient entry, and then is that really efficient, long term, and is it really stable as a long-term construct? And then, if you have to set market rules according to what is subsidized and unsubsidized, isn't FERC going to have to litigate all the various incentives—all the various regulatory and financial incentives that are given to all the various resources, and isn't that a tangled mess we can't get out of?

Respondent 1: I think it's a multi-part question. I'll try to take some of it. Part of what you're describing illustrates the challenge that resource adequacy paradigms are facing, which is, there's such a diversity of different types of resources, and they're providing attributes in different ways and different places, such that it's harder and harder to try to capture that within a single long term construct. Now, what pay for performance and the other types of markets are trying to do is define what they want out of a capacity market, which is sort of to be able to provide energy on demand under a specific set of circumstances. And we can debate whether that's the right standard. Some resources are providing energy, on average,e at other times, and so maybe they should get some value. But that sort of comes down to the question of, how do we define reliability through a resource adequacy market? And so, I read your characterization that you're not allowed to participate as meaning that you don't agree with that definition. And that's the appeal of energy prices. It sort of tells us how valuable your energy is when it's operating. I think the favorable characterization of pay for performance and other types of incentive mechanisms in the East is that they're trying to get aspects of that in, maybe very imperfectly. So, I'll stop at that.

Respondent 2: First of all, on capacity performance, that was actually intended, not to discriminate against renewables, quite the reverse--bonus payments for wind resources or solar resources that are there in the performance assessment hour. Now, we haven't had any performance assessment hours in a while. That goes to some other discussions about the one in 10 reliability standard that happened yesterday. And scarcity pricing, in addition, another topic that came up yesterday, is something that needs to be addressed more effectively. We need to do a better job with scarcity pricing. Both of those, I think are consistent with and supportive of renewable resources, but I don't agree with you that capacity performance is somehow hopelessly biased against renewables. Quite the reverse.

And then, secondly, of course there is a complicated mess of subsidies that go down to the most minute local zoning ordinances, but the fact that it's complicated doesn't mean we can't draw a line somewhere, and we do have to figure out where to draw the line. It's going to be an approximation, but I don't think it's impossible to draw it, and again, it's not about intention, it's about impact. And if you have a significant impact on wholesale power prices, then it becomes relevant, and that proves jurisdiction.

Question 11: One line of thought that has come out through the presentations is that we're in a situation where we have oversupply. We're seeing low prices. We have some forms of generation that are not economic, and yet they're not retiring, and instead they're seeking subsidies from their states to stay online. And what do we do in that case, and how do we sustain competition in that case?

But I think another line of questioning, or another set of issues that seems distinct to me, but that may be bunched up with this first question, is that the capacity markets, or the markets, only value megawatts. And states, on the other hand, or customers, on the other hand, have preferences, and they want to be able to procure certain types of resources, or at least certain types of attributes in their resources, from the markets. They're not able to do it directly through the markets, and so that's why you see out-of-market activities, because they can't go through the markets.

So, are there really two different types of solutions? Like, for example, to address the latter issue, we've talked about the carbon adder proposal to try to internalize the externalities from carbon, but we know that doesn't include other attributes of renewables, like wind and solar. And we're not about to add on, like, nuclear waste adders or like other types of criteria, pollutant adders, and we could go down that route.

Is there a way to allow states to competitively procure various types of resources?

Respondent 1: I'm going to take the liberty of saying that you're actually factually incorrect. As a retailer, there are many of us out there offering different varieties of green and clean. I don't think anybody's offering just coal, [LAUGHTER] but pretty much everything else is being offered. So, there is a fallacy in your underlying statement about those products not being available to customers. They are in fact available.

Questioner: Can I clarify that just a little bit? So, I'm talking about the capacity market, where we say, "A megawatt's a megawatt, and we have to buy whatever clears." So, if it's gas it's gas. We can't specifically procure renewables through the capacity market. That's what I mean.

Respondent 2: So, markets work when you have a single homogenous commodity. But part of what we need to do with DERs is to give customers much more flexibility about choice. They need to be able to avoid the capacity market costs entirely, if they want to. They need to be able to avoid high-cost energy hours, if they want to. The interface between wholesale and retail needs a lot of work in order to make that possible, but you can't build particular technologies into the capacity market. I mean, you could, mathematically, but it would be a mistake, and you'd end up having inferior resources and price differences that don't really make sense and aren't consistent with a competitive outcomes. So, the short answer is that individual customers have choices. And we need to get more flexibility to end use customers to avoid what they want to avoid.

Question 12: Speaker 1, you've made a pretty compelling case that we want to sustain markets, because competitive forces give you efficient, least-cost kind of results. That is something you repeated a couple of times. And when you were looking at the case of the nuclear plants in PJM, with their going-forward costs… (New nuke isn't economic. I don't think anybody thinks it is.) But looking at the existing nukes, you've got some of them that you think clearly are economic, and at the other end you have some covering only 61 percent of that going forward costs, and you think those probably aren't. The ones I'm concerned about are in the middle. And so, my question to you is, do you see the potential for an inefficient result if the wind that's been mandated and subsidized in PJM, that wouldn't have been in the market, but for those interventions, is disproportionately suppressing the price off peak, and creating those overgeneration negative price kind of things that would lead to one of those nuclear units in the middle there closing down rather than running? It would run in a market that wasn't distorted by the renewables and that priced carbon, but instead it is closing down. Can you see that a possible sort of inefficient result?

Respondent 1: It's an interesting, complicated question. We can't ignore where the nuclear industry came from in the first place. So, when we talk about subsidies, we should look at the lifecycle of these industries, and nuclear wouldn't exist but for subsidies that were created by the government for various reasons. And there are lots of existing subsidies for nuclear power plants, as well. So, it makes sense to try and compare subsidies across all power sources, but to address the question directly, of course RPS can and does distort the market, I think much less so in PJM, just because there was less than five percent renewables in PJM, for example, in 2016. But, yes, the point is to remove all subsidies from the markets to the extent we can.

I think there's a more rational way to approach the RPS standards, but, at the very least, FERC should take jurisdiction back over them, because they clearly are affecting the markets. I don't think, in PJM right now, that there's a case to be made that the renewable standards are affecting, in any significant way, the economics of the nuclear power plants. And it's, the sensitivity of the cost recovery results to relatively small changes in LMPs is interesting as I pointed out before. Prices went up about 13 percent, I believe, in the first quarter of 2017 in PJM, and that made adifference, if you just extend that for the rest of the year, between the bottom quartile covering avoidable costs or not covering avoidable costs.

So, yes, of course RPS standards can affect prices. Do we need to deal with that? Of course. But I don't see that being the key trigger, at least right now, for the viability of the nuclear plants. Did that answer your question?

Questioner: It does. With regard to subsidies, a lot of the nuclear subsidies are like sunk costs. They don't really affect bid price on nuclear power, if you're talking about the R&D as a byproduct of the Manhattan Project or something. But as you think about the California experience, where renewables, instead of being at five percent, are at 12% or 15%, and now you've got some significant price suppression, and we're seeing a number of nuclear plants that look like they were economic to keep going, but these distortions are closing them down around the country. So, do you worry that you get five or 10 years down the road here, and you're at 15 percent renewables, and now you've got significant price suppression that's leading to this kind of distorted retirement story?

Respondent 2: The goal is to avoid all of the distortions. So, the goal is to avoid that distortion as well, and to the extent that it is significant and affecting markets, that needs to be addressed as well. I'm not focusing entirely on subsidies to coal and nuclear. Subsidies to renewables also have to be addressed directly.

Questioner: So, just one last follow up question. If those renewables subsidies and mandates are a given, is there then a case to do something as a kind of second best to offset the distortion?

Respondent 1: Well, it would not be picking particularly uneconomic units. Some of the nuclear power plants are stressed right now for good reason. They're uneconomic because they're a single unit. They're uneconomic because they're in a bad location. They're uneconomic for various reasons. If you keep those around, they make the problem worse. If you sustain, through subsidies, units that are not otherwise economic, they tend to create the need for more subsidies. And you're not solving the problem. So, of course, RPS-type standards can affect prices longer term, and we need to avoid doing that, but I don't think the solution is not to pick on individual units. If we're going to do something else, which I don't recommend, it would be to have an auction for low carbon resources of all kinds--renewables, demand side, energy efficiency--and see what the cheapest way is.

Respondent 2: I guess this sort of goes back to the question about how do you redirect this? I mean the short answer is, there's a case to be made, sure. I do worry that, perversely, we're driving out one set of zero carbon resources in pursuit of a carbon reduction policy and when we're retiring a nuclear plant in California, and we have aggressive carbon goals, I do worry about that. But one subsidy after another is a really troublesome route to go.

But it does illustrate the issue of trying to pursue green policy through subsidizing green, rather than charging for the externality. Because nuclear is the first casualty, or potential casualty.

Question 13: The one thing that I'm surprised that we haven't heard about is the fact that demand growth, or total energy growth, is nonexistent. In fact, we still haven't gotten back to 2007 levels in PJM, let alone nationwide. And markets are supposed to reflect the underlying fundamentals. Guess what? They do. And so the question that leads me to is, why is the regulatory system providing such incredibly high returns, compared to just generic market returns? And I say, "generic market," meaning, if you put your money into a diversified portfolio of equity assets. That's the first question.

My second question is, why is it, in this industry in particular, that there's an expectation or almost a God-given right to have above-market returns? And isn't that causing the problems that we're seeing today, with subsidized resources and the rent-seeking behavior that's going on, whether it's with nuclear units, coal units….? So, why is it that we see this over and over again? And I think that's part of the fundamental problem.

Respondent 1: Can you clarify what "above-market returns" means?

Questioner: I'm talking about "above-market returns," meaning, on a risk-adjusted basis, earning greater returns than you could on a broad portfolio of equity assets. Right now utilities are earning way more than putting your money into the S&P 500. And there's much lower risk, if you look at equity betas. Why is that the case? And it's been historically the case. Why is that? And why does there seem to be this attitude almost of, "I have a God-given right to these returns. And if I don't get them I'm going to take my ball and go home?"

Respondent 1: I don't know what the S&P returns have been over the last 10 years, but I thought they were north of 11% or 12%. And I ought to compare that against utility returns?

Questioner: Risk adjusted.

Respondent 1: I understand. And I don't know what the S&P and the beta of an S&P index was, and I'm sure it's a lot lower than what I understand…

Moderator: You've left the panel speechless. Let's go to the next question.

Question 14: I get very concerned about language, particularly because I think the principal problem here is around the environmental issue. And when someone says that resources are "economic" or "uneconomic," or that prices are distorted, when you're talking about a resource that might well be cost effective to operate at a price that included a carbon price, but is not cost effective today, I find the language about calling that uneconomic somewhat disturbing, because it implies a prejudgment of what the policy should be.

So, having said that to start, I think that there's this fundamental problem that most of what we're talking about is we're talking about states trying to pursue second, or in some cases third or fourth, best policies in the absence of a carbon price. And so, if you're saying that we have to go with just whatever the current wholesale capacity prices are, if you're saying it's OK to have a zero carbon price, and it's OK to have no state policies that have a significant impact on the wholesale prices that are designed to mitigate carbon, then I don't think that's an acceptable answer. It's certainly not an acceptable answer from a state perspective.

The question is, is there a way, within the organized market, to build, much like has been proposed with the EIM in California, a carbon adder that allows states that want to price carbon to have that carbon price in the market for those resources that will serve their customers, and not have it for resources that will serve other customers? So, for example, Illinois could have it and West Virginia not have it, within PJM. And could we still have a workable market, and how can we go about doing this in a collaborative way? Because I'm afraid that if we end up in the litigation route, we will, in effect, destroy the markets we have, because states will find ways to reregulate, and we'll just loose what we've got.

Respondent 1: I'm sorry that I gave disturbing and unacceptable answers. Those remain my answers. [LAUGHTER] But, I agree with you that it makes sense to have a carbon price. I would say that it is not possible to have a carbon price in one state and not other states. I think it is possible to have a carbon price in PJM. I think it is very doable, and I think you're right about collaboration, and I think the states and the RTOs and FERC should be getting together right now and talking about what a sensible way to deal with carbon is, if that's what they want to do. I mean, there really haven't been very constructive discussions about this. There hasn't been adequate modeling. There hasn't been enough understanding of it. There's a lot of pontificating by me and others, but there is real work to be done, and I would love to see a collaborative effort (and I've said this repeatedly), beginning right now, to try to address it, because it could be addressed in a carbon price across the PJM footprint. Even though it wouldn't be perfect, it would be a lot better than the current situation. But the one-off stuff can't work, and will end up destroying the markets.

Comment: We're not entirely convinced it's impossible yet, so we're working very hard to see if we can do that. PJM has not yet eliminated the possibility yet. We're working hard to see if we can do that.

Questioner: And I would be happy to support that kind of collaboration. I think that's what has to happen. But I worry that we won't get there. Can we talk about California's experiences?

Respondent 2: It's not impossible. It can be a mess, but certainly we have an example of one state having a carbon price, and trading in an integrated way with neighboring states that don't, and now Washington has kind of a carbon price, and so there's consideration about how to deal with this already underway. We have ways of adjusting. I think the key element that you're alluding to is that California actually regulates the power imported from other places, and places a carbon price on that. And, again, it's possible to do. There are a bunch of issues that have no perfect answers, having to do with shuffling resources and that sort of stuff. But there are ways to do this within integrated markets.

It can be a real mess when you have a whole bunch of states with different carbon prices all trading with each other, because you can flip merit orders in really kind of counterproductive ways. But it may be a way to sort of start down that road of convincing, maybe, the recalcitrant states that maybe a system wide carbon price wouldn't be so bad in the face of that scrambled egg of state-level prices.

Respondent 3: We've been strong supporters of carbon prices and carbon dispatch adders. We sat in rooms with the big nuclear owner that's sort of leading this effort to get the ZECs and all that. We sat in rooms with the EPA pushing carbon pricing and solutions, et cetera. But these state initiatives are not about carbon pricing. Take New York. ZECs for one nuke plant, but they let the others shut down. Illinois was about jobs and local tax base…

Questioner: But that's not the way the Illinois ZECs are allocated. They're allocated on an environmental basis, if you read the statute.

Respondent 3: So, if it were really about carbon, there's really cheap ways of paying coal plants in Texas to shut down that are much cheaper than the cost of ZECs, because that's not really what it's about. It's about resource owners basically wanting to goose their returns, and jobs, and tax base, and all that. And I think carbon is convenient.

Questioner: As a former public official, I don't agree with that premise. I'm not saying that those things don't come into play, but they come into play as secondary factors, in my experience.

Respondent 4: You can't look at New York and say that. You just can't say that. Sorry.

Respondent 5: I just talked to New York about the New York experience. We are actually investigating what would be the result of putting the carbon adder in our offers, and compare that with the REC and ZEC program. The study is still preliminary. It hasn't been completed. But, essentially, the preliminary results shows that it is very promising. That putting the carbon price in the generation offers and returning the penalties to the load service entity, the customers, actually results in a more efficient solution than the current REC and ZEC programs. So, stay tuned. We can report on that study.

Question 15: If people in this room are looking to Federal courts to save competitive markets, I think you're going to be disappointed. The sort of test of whether a state policy significantly effects a wholesale market rate, I think, is something that FERC will apply to market rules to figure out how to mitigate the effects of these policies, but I'm skeptical that it's a test that Federal courts will apply to strike down state laws.

So, that said, I think the sustainable path forward is for FERC and the market operators and the market participants to come together and try to come up with a long-term solution. Speaker 1, you mentioned carbon price. It's not impossible for it to happen in PJM, and I understand that's probably everybody's preferred solution. You also sort of hinted at some sort of other auction possibility. The question is, is there anybody on the panel that's optimistic that this would actually happen? [LAUGHTER]

Respondent 1: Yes.

Respondent 2: Yes, you can incorporate carbon, but are you going to repeal RPS? Are you going to repeal all the other demand side management, energy efficiency, etc. subsidies? Because, effectively, you're saying that "Carbon will solve everything. I don't need to incorporate any other subsidies going forward." And that makes me a little skeptical.

Respondent 1: That's not what my yes meant. [LAUGHTER] I've been very clear about all the subsidies.

Respondent 2: To the extent that subsidies are meant to save jobs in coal plants, the carbon pricing solution is not going to address that, but to the extent that most of the action is around nuclear, maybe there is a grand bargain to be struck to even try to limit or reconcile state-level policies in exchange for some kind of regional carbon price.

Question 16: I'm going to switch gears a little bit, because so far all of the subsidies which we've talked about are sort of external public policies subsidies for the states or even the Federal government. But I would submit that there are some implicit subsidies within the RTO roles themselves, and just let me give you one example. Several of the RTOs have capacity markets, and those capacity markets call for firm capacity and pay for firm capacity. But there is no requirement that that capacity has firm fuel supplies. And, to me, that's always been a fault of the market, and to me that's a clear subsidy to capacity that doesn't have the firmness that we consider to be firm capacity in the integrated markets, which are the vertically integrated markets, which is a firm fuel supply contract. And I think that undercuts the price of gas in the markets. I think it's a clear subsidy, because, essentially, customers are taking all the risks of fuel supply. The capacity that is bidding into the capacity market takes no risks. I'd just like the panel's reaction to that.

Respondent 1: I'll naively say, isn't that what pay for performance is meant to address? And if properly implemented, that seller should be internalizing that risk then.

Respondent 2:You're right. PJM made an explicit decision not to actually require particular kinds of fuel supply, although PJM has the authority to review that. But the capacity performance has very significant penalties if you're not there during a performance assessment hour, so you have very strong incentives to be reliable. We've seen people take actions to be more reliable.

To give a broader answer, as I indicated earlier, I think it does make sense, to the extent we've relied more and more on gas, to make sure that the gas infrastructure is there, that PJM is really doing N minus one studies that incorporate risk associated with gas. All that's true, and if we're going to rely more on gas, you have to make sure it's reliable and internalize these associated costs. I think Capacity Performance is a good step in that direction. It's not the absolute final answer, and more progress needs to be made, for sure.

Comment: And it may be that the issue is more pronounced in New England than it is in PJM.

Question 17: Speaker 1, is there anything wrong with the fixed resource requirement (FRR) model? You talk about destroying markets. Is it more accurate to say that the fixed resource requirement simply limits the market? And if you want to force collaboration, is a way to do it to ruthlessly enforce MOPRs (minimum offer price rules) and enforce people to pick FRRs if they don't want to have double payment for capacity? Because in litigation the fight always ends up turning into, we don't want to double pay for capacity on one side, and yet, we have to maintain a market wide clearing price on the other.

Respondent 1: Your question is, I think, perfectly posed, and I agree with your conclusion. That is, that a ruthlessly imposed MOPR, together with the option to be FRR (for those of you who don't know all the acronyms, FRR just means you can opt out of the capacity market. AEP did that when they first joined PJM. They have to meet all the reliability requirements, but they're not buying or selling in the capacity market) remains an option. And that would be a way to limit, if not entirely eliminate, but limit in a very significant and appropriate way, the impact of those entities on the market. So, yeah. I think you're exactly right.

Respondent 2: It would undermine retail competition, of course. That's part of the fixed resource requirement. When you think about a state having to supply out five years with an

LSE, that would be a very tough thing. So, I see that as a problem with the questioner's solution.

Respondent 1: Clearly, if every state went for FRRs, we would not have a market anymore. So, just to be clear, it's not a market solution, but if a small number of states really want to not be in the market, that's an option.

Comment: But we don't regulate stupid, right?

Respondent 1: That's what I heard.

Question 18: We're at the start of an appellate court process in what we're seeing in all of these Eastern regions, and it's generally not a road map for speed and for resolution in that context. And I'm wondering, how do the policy makers and how does the industry really make progress in the interim on deciding "what world we want to live in," with these issues, while we're waiting to see if the Supreme Court takes up these cases?

Respondent 1: Somebody a minute ago accused me of trying to force collaboration, and I don't think I was trying to do that, but I think that talking and actually seeing if there's a solution and seeing if the states are continuing to be committed to markets, or whether they want to end markets… But I'm assuming the states continue to be committed to markets. They've seen the benefits that markets bring.

So, again, just to repeat what I said before, we move forward by starting a process which could actually lead to a solution, at the very least educating everyone so everyone's on the same page and can make rational decisions. I think at the moment a lot of irrational decisions are being made. I mean, the implicit carbon price in a $200 SREC is, I don't know, $400 a ton, which is not consistent with any rational value of carbon that anyone has put forward. So, sitting down and having a process that leads to a rational discussion and at the very least narrowing the options, so people can make sensible decisions--it seems like an obvious way to go. And I agree that, even though litigation is inevitable, and it's occurring, it's going to take a while to answer the question.

Question 19: An earlier and I think very insightful comment made a point that included the importance of affordability of electricity to the end use consumer, which is something that really didn't come up much today. Essentially, that's a foremost concern of any state regulator. In response, one of the panelists characterized states as having to really make a choice between taking a path of picking which resources get built (I would characterize that as the visible hand, anti-Adam Smith approach) versus taking a more market-based approach and letting the market select the resource mix.

What do the data say, particularly from the California experience? So, as California's gone down this path, for the last 10 years, of a more IRP-based procurement, what actually happened to retail rates in California, and are they becoming more affordable, or not? And then, what does that, the data and the experience in California, tell us about what we should expect about the affordability concerns of state regulators in other states, if they are to go down that same path?

Respondent 1: There's an important distinction about joining an ISO if you are vertically integrated. You can still participate in regional markets, and take advantage of the efficiencies in the short term without necessarily transitioning fully to the invisible hand. And so, there are still advantages there.

Now, on California, it's sort of a leading question, I guess. There's just such a mess here that I don't know if you could attribute clearly to any one factor the fact that rates have been stable, which is really a way of saying that California rate payers have not enjoyed the decline in gas price, that many rate payers in many other parts of the country have enjoyed. My own take is that this is sort of the balance--the cost of the renewable mandates have more or less offset the windfall that lower gas prices would have otherwise provided, leaving rates more less stable. I think we're going to enter a period where rates are going to start to climb, as the RPS gets more aggressive. What's interesting is you're seeing a growing wedge between the wholesale market prices and the retail prices. And we always think, whenever that wedge gets big, that things get interesting in the regulatory policy arena, and that's where all this discussion and distributed bypass and other sorts of things are going to come up. So, I think the more important aspect has been the renewable mandates, which have been sort of implemented through an IRP mechanism, but didn't have to be. And I don't know if you can cleanly claim how much of whatever's happened with rates is due to the fact that it's sort of a centralized regulatory procurement, versus all the other policy goals that have been layered onto the process in California.

Respondent 2: Ultimately, price is what matters. The intent of markets is to make power available at the lowest possible cost, no lower, but the lowest possible cost. I think markets do that. It does not appear to me that the California model would be lower cost than a market system, probably, if anything, quite substantially higher. And if you look at capacity clearing prices, for example, in PJM, and the net revenues to participants, they're clearly below what would have occurred if it had been a fully cost of service-based model. And that's assuming we would have had the same units. We might well have had different units.

Again, to go back to the purpose story, why do we end up with competition? Because there were bad decisions being made about what kind of resources to build, control, and costs, and all those things. So, I think that the evidence is pretty clear that markets result in a lower cost outcome.

Respondent 3: I'm not sure it's just completely cost. I think there's a risk allocation aspect to this. In the California model, rate payers are on the hook for the next 20 to 30 years for all the technology risks and market risks, et cetera, associated with what they're signing up for. Whereas, if you are in a competitive market, that's on us. We build a plant, and someone builds a better plant in five years, seven years whatever. That's our risk. That is not passed along to rate payers. So, I know it doesn't directly answer your question, but I think that that is sort of a component of the analysis.

Question 20: I think two major things have happened in the last month, and the first is, at the FERC Tech Conference, we heard almost every state say (and this was just focused on the Northeast), "Despite the fact that we're taking all these actions, we don't want resource adequacy back." And yesterday, Trump announced that we exited the Paris Accord, which means states are really just going to double down on their efforts, and a lot of them are in the Northeast. So, while we're talking about, ":et's just MOPR for everything," or, "Let's just make sure that these terrible proposals that the ISOs are coming with, we just dismiss them," I don't think that's helpful, and I don't think that's where things are going.

What would be really helpful is if a lot of the people in this room actively engage in helping to make those proposals the best they can be. Because we are in a situation where states are going to do what they're doing, and we have to accommodate that. And even while the ISO is looking at carbon pricing, whether that's a pie in the sky idea, and whether it can ever happen--we'll see, probably someday. Maybe not sooner rather than later. It's still not sufficient to do what New York wants to do. It could help price carbon, and perhaps keep the nukes on, but New York, in particular, has pretty significant transmission constraints. The West is very different from the East, and even if you price carbon, you're not going to displace really high-emitting carbon resources in the Eastern part of the state where most of them are. So, carbon pricing isn't even a full solution to what New York State wants to do. So, we have to engage with these other proposals that are coming forward about looking at two-tiered capacity. Whatever they are, we have to actively engage in these, and think about whether or not we can help these markets transition during this period when we're looking at all of this really significant change, and it's unhelpful, I think, to just dismiss them out hand. We have to engage with those.

Respondent 1: We have to accommodate localized politics, is that what you're suggesting, as well?

Questioner: Whatever the state policies are. I understand that they're not necessarily what they're framed as. I get that, but they're doing things, and they're going to do things, and they don't want resource adequacy back.

Question 21: I spent around 30 years in the software industry, and I spent probably 15 years of that in sales and sales management. And one of the things I tried to do for many of those years was to help my sales people understand the difference between selling a commodity and selling value. And the big difference between commodity and value is differentiating certain characteristics of your product that add value to the customer's needs. And I think that's a conversation that we're starting to have now in the utility industry, because, as I see things, certainly electricity is treated as a commodity in the markets. There's no difference between an electron generated by coal versus an electron generated by solar. But then, there are companies that prefer to get their power from solar generation, and they're willing to pay more than they would pay for just that electron, because of the differentiation that solar brings. It adds more value to them from the perspective that they want to be climate friendly, they want to be green, things like that. I think we need to expand the conversation from just looking at differentiating between green and maybe less green or not green at all energy, and starting to talk more about some of the things that we talked about yesterday. What are the values associated with the different generation types? What are the advantages and attributes that add value to those generation types? And maybe we should start to rethink things, not so much from a commodity basis, but from a value basis, and start differentiating those different resources by the characteristics and advantages they bring, and that just kind of a final comment on what I've been hearing the last couple days.