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Rapporteur's Summary***Session One.****Uplift Downside**

The simple model of electricity supply and demand utilizes locational market-clearing prices for load and generation. The model is silent on the treatment of overhead costs and other administrative payments. Traditionally these relatively small costs were relegated to market design fine print under the British label of “uplift” charges. Thought to be a minor inconvenience, the growth in uplift charges has been a source of increasing concern and controversy. What are the sources of costs that are part of the uplift? Why has the uplift category expanded? How do uplift costs support reliable economic dispatch? How much of uplift is necessary, and how much is a reflection of defects in market design? How do uplift cost allocations affect load, generation, virtual transactions and all the many steps in the electricity system? If retail consumers desire fixed rate contracts, how can retail aggregators face increasing uncertainty in uplift costs, which threatens the business model of these providers? Do increasing uplift costs create a risk that can threaten ongoing development of retail competition due to increased hedging and risk management costs? How does uplift affect the incentives and opportunities for market manipulation? How might uplift rules interact with price determination? How can we live with the necessity for some uplift and avoid the downside of uplift charges growing out of control?

Moderator: The topic this morning is uplift, which we titled as the “uplift downside.” Uplift is a term which I first encountered in the UK these many years ago, where they coined or used this phrase, and it basically referred to “other costs that we don’t know what to do with.” They

were going to have to socialize and charge everybody--somehow allocate the costs across all the various customers. And initially the focus was on things like administrative costs and running the software and all the other kinds of stuff that go with it. We thought the admin uplift

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part was necessary, unavoidable, and just a minor annoyance.

Then the next category of things in uplift was a variety of things that go under the heading of “ancillary services,” services like black start capability that have to be provided, but they don’t really fit into the general pricing model that we have, and they don’t get handled that way, and so you have some costs, and they get put into the uplift.

And then we started seeing things like out of market actions (“OOM” is the phrase you’ll often see), and that category involves actions that system operators take for a variety of reasons. And the reasons can range from the fact that there are properties of the electricity system that we don’t capture in our dispatch models, but experienced operators know about, and it’s just the reality of nonlinear dynamic systems that you have situations like this and they have to take certain actions in order to protect the reliability of the system, all the way up to mistakes. So we have a whole category of things where we sort of screwed it up, and we made a mistake, and we didn’t model the system properly in the day-ahead, for example, relative to the real-time, and that creates additional costs. And we know how to solve those problems in principle, but we haven’t solved them in practice. And they go into this uplift category.

Closely related are capacity payments, when we have capacity markets, because that gets averaged across the customers and allocated in ways that are similar to uplift, and it’s related to deficiencies in the energy pricing, the missing money problem.

And then, finally, there’s another category where there’s a lot of work going on, particularly, for example, in the MISO, the Midwest Independent System Operator, dealing with startup and no load costs, the minimum run times, which all go under the heading of lumpy or non-convex kinds of problems that don’t fit

into the normal pricing model, and they go under the heading of “extended LMP,” which is actually trying to find energy prices and reserve prices that minimize the uplift.

So there are a lot of categories in all of this. And once we figure out what all of these are, and we try to get as many of them as possible out of uplift and priced into the energy and reserve markets, there’s always going to be something left over, and we’re going to have uplift payments. So this isn’t going to go away.

But then we’ll come down to questions about allocation of those costs, and that’s a complicated problem and often creates a kind of paradox in the way that we actually do this. For example, when you do the cost causation analysis through the energy prices, marginal pricing analysis, you have costs that are left over. And now the question is, “How do we do the cost causation analysis for the costs that are left over?” Well, almost by definition, the question doesn’t make any sense, because, by definition, these are the costs that we can’t do through cost allocation, otherwise we would, and that would be the answer.

So now the question is, “How do you deal with those costs and allocating them?” And here you get into beneficiary pays arguments, very similar to the transmission cost allocation problem, and making sure that we don’t screw up everything else through the cost allocation mechanism. So there’s trying to make it compatible with the rest of the market, and that raises a number of policy issues.

And these numbers, unfortunately, can sometimes be not just a minor inconvenience, as we will hear from our speakers today. They can be a material problem in the sense of impacts on the markets. And we have a terrific panel here available for discussing this.

Speaker 1.

Thank you, and good morning everyone. It's certainly a distinct pleasure to be with you again here at the Harvard Electricity Policy Group.

I think I would summarize the moderator's introductory comments by saying that uplift costs are a necessary evil when it comes to electricity markets. Certainly I think, as I'll try to get to as I go through my slides, we do everything we can to minimize the uplift costs that our market participants are exposed to, but at the same time there is a certain amount of these costs that we just simply cannot get rid of. So there will always be some level of uplift. The idea is to minimize it and to make sure that it does not perturb the result of the electricity market and cause problems for market participants, to the greatest extent possible.

So I thought what I would do to start off with, is just to sort of categorize, if you will, the various types of uplift costs that we see in the electricity markets. This is probably not a comprehensive list, but it includes the big ones that I thought were really important.

The first category I list is what most people think of right off the bat when they think of uplift costs. These are the energy market uplift costs. In the ISO/RTO electricity markets, I think it's pretty typical that we allow three part bidding on the part of generation resources. So, startup, no-load, and incremental energy costs are all part of the offers that are submitted for dispatch by the system operator. And we also allow generation resources to inform us of physical unit constraints that must be respected as the system operator is committing, scheduling and dispatching resources--things like, obviously, economic minimum and maximum levels, start up notification times, minimum run times, maximum run times--all those sorts of things are respected, because we have to realize that we are dealing with physical resources on the system that have physical limitations.

In PJM we do have separate day-ahead and real-time components of energy market uplift. We call them "day-ahead" and "balancing" operating reserves. These are fairly broad buckets with many components, and I'll get a little bit into the calculation of the uplift costs themselves. The make-whole payments to generators in the day-ahead and real-time energy markets are complex in and of themselves, and the allocation of those costs gets even more complex, which gets into some of the transparency issues that we'll be discussing today as well.

The second category (that I think the moderator actually didn't mention in his opening comments) are the financial transmission rights markets, when we have underfunding of financial transmission rights (FTRs), which has become a fairly significant issue for PJM for several reasons over the last several years. That underfunding has to be allocated somehow, and I view that as another type of uplift costs that FTR market participants are exposed to by virtue of their participation in that market. And I think one of the things we'll see as we go along here is that there actually can be a tradeoff between uplift categories. So actions taken in one particular area, such as energy market operations and getting everything possible into the LMP to minimize energy market uplifts, can actually have impact when it comes to FTR revenues, and, if not done in the optimal way possible, can translate into underfunding, which then needs to be allocated as a different type of uplift. So it's a very interesting sort of interplay, if you will, between various markets that we operate with respect to how uplift in one can be transferred to another in an effort to minimize it.

My third category is demand response, which, again, is probably something folks don't typically think about as uplift, but as a result of really treating demand response as a supply side resource, and paying the energy price to demand side resources, that has to be allocated, again, as another form of uplift.

And my fourth category (one the moderator did mention) is ancillary service markets. When I think of uplift there, I typically think of the areas where we actually operate markets for ancillary services, primarily regulation and synchronized reserve and non-synchronized reserve, to the extent that all the costs of the resources that are assigned those services are not included or are not covered by the clearing prices. Again, there are make-whole payments that are necessary and uplift costs that can be associated in those markets as well. Those, I think, are the minority of what we're talking about. They're very small compared to some of the other categories, but they do exist as well.

So, to talk a little bit about my first category of energy markets and, specifically, operating reserves, this chart, "PJM Deviations Balancing Operating Reserve Rates," illustrates a couple of things. First of all, one particular problem with the uplift that is allocated through operating reserves is it can be extremely volatile. So the costs that can be allocated can change significantly during different times of the year and with different types of operating conditions. This past January was the poster child, I think, of significant uplift costs being allocated through operating reserves.

This particular chart shows three different types of operating reserve costs that are allocated to deviations and points out, really, a second issue with operating reserves, and that is the complexity of the allocation of these costs. The genesis of these costs, even though the calculations themselves can be somewhat complex, is relatively straightforward. We have physical generation resources operating at the direction of the system operator. If LMP doesn't completely cover their bid-in production costs, they get made whole for the difference. A fairly straightforward concept. The allocation of these costs in PJM we have now split up into, I think, nine different rates. So we have different rates, depending on whether these costs get attributed to deviations between day-ahead and real-time

quantities. We have rates for costs that are incurred in order to maintain system reliability, which get allocated to real-time load. And then we have costs divided according to location on the transmission system and location in the RTO. So we have an east and a west and an overall RTO rate for each of those other two types of rates. And so the allocation of these costs and how they are divided into these different buckets was discussed over about a two year process, in about 2007 and 2008 through the PJM stakeholder process, which was an attempt, really, to get at this cost causation principle, this beneficiary pays principle, if you will. And the danger, I think, in trying to go too far down that road is that the calculations get so complex that they introduce transparency concerns, because those to whom this cost is being allocated (and I know you're going to hear more about this from some of the other panelists) had very little insight as to why the costs that are being allocated to them are being allocated to them, which leads to an inability to predict these costs going forward, and certainly to an inability to hedge these costs on the part of those that are exposed to them, and I'll get into that in a little while.

So we are revisiting this allocation in the PJM stakeholder process, and I think that's what our moderator was referring to when he said that PJM's sort of in the middle of these issues. We actually had stakeholders that were stimulated to reengage in this discussion, given some of the high uplift costs that we saw last summer in July and September, and certainly the January events, where we had many times the typical level of operating reserve costs, have really added some additional stimulation to those discussions. And I think the tradeoff that we're really going to talk about with the stakeholders is, do we go down a road, again, of a high-complexity type of calculation that tries to get at beneficiary pays and cost causation-type principles, but can lead to very counterintuitive allocation results and certainly a difficulty with transparency? Or do we try to get at something that makes these costs

much more predictable on the part of market participants, something that comes at it from more of a standpoint of asking if we can charge market participants a flat rate for their particular category of market participation that will cover these costs on an ongoing basis and maybe over collect sometimes, under collect some other times, but make these costs much more certain for market participants and take away some of that uncertainty and the associated risk that goes along with it. So those conversations are ongoing in the PJM stakeholder process--really just kind of getting started at this point.

I'm not going to say too much more about FTR underfunding than I already have. I know that Speaker 4 in particular is going to cover this topic extensively in his slides. So I won't steal his thunder. But this next slide is a chart showing FTR revenue adequacy in PJM, and you can see that over the last several years we have dipped much lower than we have historically, and the allocations of these costs have become a particular issue. Getting at a little bit some of the transference, if you will, of uplift costs from one bucket to another, FTR underfunding is usually where we see it. In an effort sometimes to get as much of the cost of operating generation for reliability constraints into the LMP, there can be times when you actually restrict transmission system capability in order to make sure that that happens, and when you restrict transmission system capability in day-ahead and real-time, it leads to FTR underfunding. So sometimes, if you haven't started at the very beginning in your FTR auctions with looking ahead to how much you may have to restrict transmission system capability to get everything in the LMP, if you do so in day-ahead and real-time without having it in your FTR auctions first, it can lead to FTR underfunding. I'll leave it at that for now.

Just a couple of words about ancillary services. We made some significant changes. This slide is a chart showing our regulation market results. The blue line is lost opportunity cost payments,

those uplift payments in the regulation market. The red line is the regulation market clearing price. Back in October of 2012, pursuant to FERC Order 755, we made some significant changes to our regulation market that were very successful in getting more of these costs into the transparent clearing price, and you can see that from October of 2012 all the way up through January and February of this year, what we saw was an almost doubling of the regulation market clearing price and a significant reduction in the amount of uplift payments in the regulation market. So, pretty successful changes in order to get more of these costs into the clearing price, and less into the uplift bucket. Again, ancillary service is very small in terms of dollar values, compared to the other categories of uplift. But, again, we've been fairly successful in making some changes that can make the clearing price more accurately reflect the cost of all the resources that provide these services. Sink reserve really has been very similar as well.

Just a couple of words about demand response. The uplift payments for demand response really are a result of the payment of full LMP to demand resources that respond. Given the recent circuit court order, in the words of Forest Gump, "That's all I have to say about that." [LAUGHTER] I'm not sure we want to derail our conversation and get into exactly what could happen with that. And, again, these are fairly infrequent, and compared to other types of uplift fairly small, but again, they do exist. I think some of the problems that you'll hear with respect to uplift costs in the market in general, are non-transparency and the inability of market participants to hedge it. From PJM's perspective, I think we see this impacting most significantly those load serving entities that serve retail customer load, because the more that they can contract forward and hedge and develop a portfolio of hedging opportunities for their load serving obligations, the more they can minimize their risk and the more efficiently they can serve that load, and they can do so at the lowest cost to the end use customer, and that

really is our goal. Certainly, though, uplift affects all types of market participants and really has the same types of impacts. So some of these costs are allocated to generation owners as a result of deviations between day-ahead and real-time quantities. There are allocations to our financial market participants. And as we all know, financial market participation in the day-ahead market helps with liquidity in the day-ahead market and competition and therefore lowers, again, the total cost of served load. So, really, any market participants these costs are allocated to, it really hurts their business, increases that unquantifiable risk that they just can't get a handle on, and therefore increases cost for actually serving load.

The last thing I'd point out is, to the extent that uplift cost exists, and therefore all costs are not put into the transparent clearing prices, whether it be for energy or ancillary services, capacity, or whatever it turns out to be, it really dilutes the value of those price signals. And part of the reason for having those price signals in the first place is to drive innovation. And we've seen that occur, in particular with our regulation markets, seeing alternative resources providing the regulation service. And, again, the more we can minimize these uplift costs, get more into the price and make these prices as transparent as possible, the more meaningful they are as far as driving that investment and innovation that will make our markets more efficient.

I mentioned the ongoing discussions in our stakeholder process with respect to the allocation of uplift. The point I wanted to make is, we may get to the point where we change our uplift allocation, and we're weighing the benefits of various types of allocation. Do we go, again, down the road of cost causation, beneficiary pays-type concepts? Or do we sort of pull back from that and allocate these costs as broadly as possible to minimize their impact on all market participants and try to make them more certain for market participants? But no matter which way we go, it's really incumbent

upon PJM as a system operator to do everything possible to minimize them.

By way of closing my remarks this morning, I wanted to just inform you about some of the things that we have done more recently in order to try to get a handle on minimizing these uplift costs, particularly with respect to the energy markets and security constrained economic dispatch. First of all, "leaner" scheduling practices. Towards the end of 2013, we realized that we were seeing a sort of ever-increasing level of balancing operating reserves as a result of uplift payments made to generators that were being brought online in order to make sure the transmission security constraints could be controlled. And we actually found an issue in both the software application and the processes by which it was being used that was sort of overestimating or over calculating or resulting in too much generation actually being scheduled for some of our larger West to East 500 KB transfer constraints. And you'll hear it anecdotally referred to in Speaker 3's presentation, but there was a point in late December of 2013 where we actually made a fairly significant change in how that scheduling is done. And it resulted in fewer larger inflexible steam unit commitments in order to control those transfer constraints and more reliance on higher marginal cost but much more flexible smaller combustion turbine units in order to control those transmission security constraints. And that change significantly reduced the amount of uplift that we have had to allocate as a result of balancing operating reserves, again, all things being equal. January is sort of an outlier in and of itself. You'll also hear some more discussion today about what we've implemented called "closed loop" interfaces. And one of the operational difficulties that our moderator alluded to in his opening comments was some of the transmission security constraints that are difficult to get into locational marginal prices. And in order to get transmission constraints into locational marginal prices, they always need to be translated into a thermal type

of a flow constraint. So, a megawatt sort of flow constraint on a given transmission facility. What's really not possible to get into LMP directly is a voltage constraint on the system--a situation where the voltage would otherwise be too low or too high without making adjustments to how generation is dispatched on the system. They need to be translated into a thermal flow constraint. And one mechanism PJM has utilized in the past and we're utilizing more is to create these closed loop interfaces around areas in the system where voltage is an issue, either on the high or low side, so that we can create a pocket whereby inside that pocket, when we need to operate generation, we can model that closed loop interface as a flow constraint, and actually get the operation of that generation resource into the LMP appropriately. So these closed loop interfaces are what allows that translation from a voltage-type constraint into a thermal constraint that allow those resources to set price. If those closed loop interfaces, though, are not included in the FTR processes, that can lead to FTR underfunding, which is that transfer from one uplift bucket to another that I talked about a little while ago.

And then obviously, any time transmission upgrades come into play that eliminate transmission constraints, there's no longer a need to commit resources for that constraint, because it no longer really exists.

One example of these closed loop interfaces that we've utilized is the Cleveland area. The Cleveland area is a historically constrained area for voltage problems. So this is one of the closed loop interfaces we created in order to allow us to operate generation and get it to set price appropriately. There are others on the system as well.

Last but not least with respect to solutions to minimize uplift, some of the things that we've seen on the system really in the last couple of years are really significantly related to the evolving fuel mix of generation. We are seeing

retirements of significant amounts of coal fired units. We're seeing increased cost of operating coal fired units due to emission constraints. You're going to see more of that, obviously, given the recent order. And the result of that is that some of the units that used to operate as base load plants are no longer economically base load plants. And not having those units operating on the system causes transmission constraints that wouldn't otherwise be there and have historically not existed because those resources operated as base load plants. And so when we have to keep those resources operating out of merit in order to avoid the appearance of those transmission constraints, it almost amounts to utilizing an inflexible long term base load unit as a flexible peaker unit, which is not a very efficient way to operate the system. And so transmission upgrades are going to be part of that mix, and getting these things to set price more efficiently is going to be part of that mix. But doing so, if we don't have these restraints appropriately modeled in the FTR processes, again, can just inject the uplift into another area, when we see FTR underfunding.

So these are some of the things that we've been working on in order to get more into the price, particularly in the energy market, in order to minimize the uplift costs that we've seen. And, again, we're going to continue those discussions about how we go forth and allocate balancing operating reserves in the future. With that, I'll go ahead and conclude my remarks, and I'd be happy to take any clarifying questions anyone might have.

Question: On the leaner scheduling practices, is that completed? And when did it get implemented? And then also on the closed loop interfaces, are those also used for your interfaces with any of the neighboring RTOs?

Speaker 1: The answer to your first question is, yes, we believe we have a handle on the issues that were causing the non-lean scheduling practices, if you will. Again, we saw a fairly

large step change in uplift payments that needed to be allocated at the end of 2013. So we think we have a handle on that.

With respect to your question about the interfaces, though, I want to differentiate. When I talk about closed loop interfaces, what I mean is, again, sort of a closed loop cut set of transmission facilities on which we measure the flow. And if the flow is above a certain level, then the generation inside that closed loop sets price. When I say a closed loop interface, I'm not talking about an interface with an external area, so they're really two very different concepts, and unfortunately, they have the same name. So sorry for the confusion there.

Speaker 2.

What I'd like to talk about a little bit with you today is the allocation of uplift to day-ahead market financial trading, and particularly virtual trading, and whether that's appropriate, and if it is appropriate or not, what the potential impact is on liquidity, and therefore the protective nature of liquidity in terms of allegations of market manipulation, or at least the ability to manipulate market price and LMPs. And then hopefully I can give you a cautionary tale about sort of the complexity of uplift calculations and its allocation and how that might play out in the next few years in terms of other innovations and new market participants in the marketplace.

I think sometimes taking a step back is good before you take a step forward. So, electricity markets in the US and other places are characterized essentially by economic dispatch of generation necessary to meet demand at all times. That's the goal. That is the model that we operate under. You know, there is a complexity to that, because of the physical nature of the business, in terms of how generation operates, how transmission loads, and local constraints. So that causes us to, in the marketplace, to think differently, and you end up with innovations.

Certainly LMP, locational marginal pricing, is an important component of that, measuring energy and line losses and congestion components. And LMP was meant in part to provide locational price signals for the next marginal unit of electric energy generated. It's meant to convey price signals.

Another innovation in the marketplace was the day-ahead market, the two-part market. That is, and I think it bears repeating any time I step in front of any group, that is a financial market. Nothing happens in the day-ahead market. It's a forward market. It's a market for hedging, and it has other purposes. Nothing happens until you move into the real time market and power is actually delivered. Day-ahead market is a financial market. Also keep in mind that it is a market that can be offset. You can essentially book out day-ahead market transactions. You can even do it through the tagging process in the contract path of a tag. So it's a financial market. Hopefully I've said that enough times. [LAUGHTER]

So then another innovation is virtual bidding. And the point of this brief little foray is that there is a physical market, and there is a financial market, and there are significant benefits, and the financial market day-ahead products were designed to provide benefits. So you have virtual trading, which I'm sure you're all familiar with. But, in short, you buy virtually at a day-ahead price, and you settle virtually at a real time price. Again, it's a financial trade.

And these day-ahead products, and I'm going to focus on virtuals, have a particular set of purposes and benefits. One is to hedge price differences at a particular node. Another purpose is to allow for speculation, which is someone without maybe a physical generator or physical load obligation, purely speculating on the difference between day-ahead and real time prices. Also (although certainly one wonders if FERC really buys this particular purpose) it has been a stated purpose by other ISOs and RTOs

that virtual trading can diversify settlement exposure to day-ahead prices to include real-time market prices. So another function is portfolio management, which is a little different than pure hedging, but still within that hedging bucket. And there are a lot of benefits to this financial market, and again, focusing particularly on, I guess, day-ahead physical trading, but also virtuals, a lot of benefits. For example, increased number and diversity of participants. So you have speculators. You have generation owners. You have load. You have people with different credit profiles and different purposes in the market adding to diversity of inputs into sort of a competitive mix in the day-ahead market. That in turn increases liquidity, increases the level of participation, and, I guess, under economic theory, should result in more transparent pricing and more accurate pricing in the marketplace to drive things from big things like generation development decisions, down to little things, like further hedging in the marketplace and bidding through the day-ahead and real-time markets. And also, the stated purpose, for example, of virtuals is to promote convergence between day-ahead and real-time market prices, so to help create a more predictive market, again, a financial market, and when the rubber hits the road, when generators run, transmission is scheduled, and electricity is consumed in the real-time market, to converge those price results, which is considered by many to be evidence of a healthy functioning market.

And we talked a little bit about FTRs as well, so I'll leave that aside. But these are all financial transactions that are helpful, I think, to address some of the special features of the physical market.

Another remark is that all of these day-ahead market type of products, particularly virtuals, can all be also accomplished in the financial markets outside of the ISOs, so outside of the ISO tariffs. You know, there are day-ahead real-time swaps, for example, that you can purchase that replicates the ability to buy day-ahead and

settle, or buy or sell day-ahead and settle in the real-time markets.

So that's sort of the financial markets, and we're going to talk a little bit about uplift and how that affects the health of those financial markets and their purposes. But I do want to remark (and we're not going to talk about the DC Circuit decision) that I have been a longtime proponent and discussed quite a bit the question of what is FERC's jurisdictional authority over day-ahead markets and these financial products. I'm not advocating in any particular way here, but think about it. FERC's jurisdiction really is for the sale of electric energy in interstate commerce. And these types of financial products result in no sales and certainly no delivery of electric energy in interstate commerce. So, you know, a crafty lawyer might come up at some point, either in an enforcement matter, or maybe for someone who is opposed to virtual trading as a concept, and argue that FERC has no authority in this area to even mandate or dictate or to even approve virtual trading or even uplift allocation.

So that's one thing to consider as an aside. And it also, in some sense, previews what I'm going to talk about briefly next, which is, is uplift even appropriate to allocate to virtual trading? Because, in some sense, it's not resulting in a sale. It's not really directly affecting dispatch, although it may affect unit commitment decisions. So, for example, Barclay's, they're arguing this issue with day-ahead transactions that were executed in ICE. Constellation, if you read underneath that, you can see challenges or potential challenges to FERC's authority over virtual trading and day-ahead market transactions, and this EPSA case--there's a gray line in there. Demand response is a non-sale, and there's language around that whether those types of non-sales are even FERC jurisdictional. So keep that in mind. But you know, of course, and this is why uplift is a discussion, virtual trading, for example, does have impact on unit commitment decisions in the day-ahead market, which in turn can influence how those

commitments are made, and can, in turn, I suppose, influence real-time market LMP outcomes, so there is some level of connection between virtual trading and real-time market outcomes.

So I'm not going to repeat what Speaker 1 said about what uplift is, but I do have a good quote about what uplift is conceptually, as opposed to all the specific items that were mentioned. I think this quote is from CAISO, or it might have been from PJM, "an uplift cost is simply a form of reliability uplift that benefits physical load." Well, that's a very interesting quote, because it's basically saying, uplift is meant to compensate potentially uneconomic generation, or generation that can't recover its costs through LMP pricing, but those costs are related to load, not necessarily to the participation of financial entities in the day-ahead marketplace. NYISO and MISO have other similar quotes, and certainly ISO New England has other quotes that connect on the lack of ability of generation to recover its costs as the, maybe the cost causation principle or the beneficiary principle.

So we've heard a little bit about the common uplift cost causes. But taking a step back to maybe be slightly more general about it, we've heard of out of merit dispatch as a cause of uplift. We've heard about backing down of scheduled generation--forecast errors, I think, was what our moderator mentioned... So everything from the ISO, to a generator error, and everything in between. But think about it. The reason why I'm bringing this up is, what is the relationship between that and financial trading that provides hedging benefits in the marketplace and a potential to get a more forward hedging opportunity for not only generation owners, load owners, load servers, but also for speculative entities?

And I guess one other remark is that the definition of uplift is expanding quite a bit to be inclusive of a number of other costs. A lot of them are driven by public policy and making

decisions about what should be allocated to whom. I'm fascinated by what Speaker 1 was talking about, because it is very interesting, because it is solving a problem of trying to minimize uplift. But it is very complex. And as Speaker 1 referenced in one of his slides in his remarks, it's complex, and it's difficult to predict, and it's volatile. All these things, if you're the recipient of uplift allocation, makes it difficult for you to understand it in terms of business cost, to hedge it, and it may be a negative to your participation in a particular market.

So, on the allocation of uplift costs to virtual trading, you've heard it, and it's been said in pretty much every market, "Uplift should be allocated to virtual trading, because virtual trading may cause or has an impact on the divergence of day-ahead market prices, with real-time market prices, which is evidence of some type of inefficiency." That's pretty much it. And a sub argument would be one in favor of putting limits on virtual trading, because it's related to price divergence. But to me, that doesn't make a tremendous amount of sense, because what is the relationship between price divergence between day-ahead and real-time markets, and the recovery of cost that are not easily placed in an LMP price signal? And maybe others will address that. But that would be the thought question. So, why is it appropriate to allocate uplift costs on that theory and that relationship in terms of virtual trading? A lot of the work of David Patton is very helpful in this area. He mentions that uplift has many different causes and factors other than real time market deviations, including (and I'm essentially quoting from a recent report) peaking sources not set in the real-time market price, operator actions, and unforeseen events like outages. So it does raise the question, why are uplift costs allocated in that manner? And I think PJM is at the forefront of addressing minimization of uplift costs by finding a way to include more costs in LMP pricing. And I think that's extremely important. But it still doesn't address

the issue of whether it is appropriate to allocate whatever is left over to virtual trading.

And we've heard about volatility. We've heard about unpredictability. All of these things make it very difficult for virtual traders to calculate their business model, particularly those that are speculating, and the uncertainty is discouraging them from participating in the market. Well, what is that doing? That is drying up the very benefits I mentioned earlier, which are market liquidity and market depth. It's removing that price discovery option. How does that affect manipulation? Well, what that does is, that's less market pressure in the marketplace. If there is a price anomaly because there's manipulation, or if there's a price anomaly for any reason, virtual trading cannot come in and gobble up that price impact the very next day, because they're motivated by speculative and profit seeking motives. So you have fewer market participants and less ability to react to price anomalies, including those anomalies that may be caused by market manipulation or by other impacts. So you're losing a fundamental component in the marketplace that can address market changes.

So I guess I'll leave you with sort of a cautionary tale. You know, there's a level of complexity in this marketplace that is causing me some concern. In virtual trading and FTR trading, you're seeing a lot more algorithmic based traders. I'll say they're flash traders or high frequency traders, just to get your attention, but essentially people are using algorithm-based systems to trade virtually FTRs and to trade even in the day-ahead markets, and that type of trading is even further away from what FERC is used to, which is generators, transmission lines, and delivery of energy to load, and my concern is that the complexity of uplift calculation, the complexity and potential divergent and degenerative pricing results at particular nodes, based on the modeling that different ISOs have, combined with this sort of more algorithmic based trading...first, those traders may run into more claims of manipulative conduct, because

they're hitting prices that they don't understand, and second, the charges and calculation of congestion that make up FTR are uplift based and becoming much more complex. So it's very hard to fully understand what the price signal is and whether it's an appropriate price signal to pursue for profit. So I'll leave you with that. But I'll take any questions as well. Thank you.

Speaker 3.

Good morning everybody. It's a pleasure to be here and discuss this important subject with you. When I was invited to present, I didn't think it was going to be a challenge to put together my slides, because what I tried to do is reflect the conversations that have been going on primarily since January, which was a momentous event that kicked off a lot of discussion. These are discussions with colleagues inside my company, within my sector. I'm wearing a load serving entity hat here today. My hat is off to PJM to being open to the conversation and really being dedicated to a solution. Everyone's been a part of the conversation.

And so what I've tried to accomplish in my slides is a reflection of that conversation, and what you might notice as I go through that is that there are inconsistent and sometimes contradictory points that are being made, and that's just part of the conversation that we're coming across as we look at this unclear path forward.

What I thought would be valuable is just to point out some obvious comments, because, as an exercise, we found that pointing out the fundamental needs would then highlight what might need to be changed, and then you can determine whether you can change it or not. So just from a very basic point of view, as a load serving entity dealing with customers, customers, whether they be large or small, particularly mass market customers, are interested in risk managed fixed rate products. That doesn't speak for everybody, but it speaks

for a lot of the customer base. And you need, as a load serving entity, transparent market signals and liquid third party hedging opportunities in order to be the risk manager of the products you're offering and to be able to protect your own bottom line. And when I think about risk management, obviously uplift seems to be the anathema to it. It's expensive. It's unpredictable. It's volatile. And it does threaten the retail business model. I mean, just to give you a sense of numbers, if a retail supplier is trying to make \$20 million in a year, and in a month they get hit with an unexpected \$5 million bill, that's a big hit. So at the same time, we recognize that uplift, as I think Speaker 1 said, is a necessary evil...I'm not going to call it evil, but I will say it might just be unavoidable. And later on I'll talk about why I think it provides flexibility to the ISO dispatcher and why I think it just might be unavoidable...

Having said that, I think there are a few "shoulds" here that should be identified. So my last bullet says, "Transparent costs *should* lead to hedgeable costs," but we need to recognize two things. They may not, and I'll talk about that more. And even if you reflect everything in clearing prices, there is a direct relationship between clearing prices and uplift. So higher clearing prices could lead to instances of higher uplift in certain intervals.

This slide here is just a snapshot of what I'll call "theory versus reality," and what a load serving entity might think of doing when it wants to manage its risk and hedge its position. You do have PJM market-based ancillary services, like spinning reserves and regulation and day-ahead reserves, for example, that do have clearing prices. That doesn't mean you can hedge them. They're transparent, and you can look historically at what they've been. But that's not always indicative of what they will be, and I'll explain in a minute why that doesn't necessarily lend itself to a hedgeable product. Theoretically there is an ability for a buyer and seller of ancillary services to arrange a fixed for floating

swap, and just to tell you what I mean by those words, you can look at historical clearing prices. You can agree on a forward view of the market. But there are a lack of players who are selling. You have limited trading. And if there is a seller willing to step up, they can't necessarily lay off the risk they've just taken on from other sellers. Energy and capacity are the primary costs for load serving entities and the primary revenue for generators. So that's the natural focus. So if you want to look at ancillaries as a specialized esoteric product that bids in small volume and rarely trades, compared to physical energy, you can understand why there isn't a market around these products, even though we have clearing prices, and clearing prices should lead, theoretically, to hedgeability. A tail event, like January's extreme price spikes reduces trading even more. At least in PJM, balancing operating reserves hurts the market for this hedgeability even more, because the bid/ask spread gets wider, not tighter. I think load serving entities that are interested in hedging these risks are still interested, even more so after January, in buying some kind of product. But they're going to base their interest in buying on historical levels, not the January spike, which they'll see as an anomaly, and some reasonable premium that they're willing to pay. But unfortunately, the sellers are going to readjust their sense of what they are willing to sell for based on the January price. So a tail event, like January, can actually chill and make more illiquid an already illiquid ancillary service hedgeable market.

The next bullet in my list of theory vs. reality has to do with self-supply of ancillaries. I put that in there just because I read something, and I thought it was very interesting. I'm not a student of this docket at the Pennsylvania Public Utility Commission. I did read the petition, and I just thought it raised a novel idea. Basically, there is a load serving entity that is attempting to pass through the PJM uplift charges to its retail customers under some kind of material change or change in regulation type provision that exists in many contracts in the industry. The Utility

Workers Union of America filed a petition for declaratory ruling, and the reason I thought it was novel was that what they're asking the Pennsylvania Commission to do is to determine that this load serving entity is not allowed to pass through these charges, at least to its Pennsylvania customers. And the theory they put forward is that ancillary services are within management's control, and can be hedged. So the load serving entity in question could have made a decision to go out and find some physical or financial partner to hedge this and be protected from it, maybe pay a premium, but they chose not to, and they chose to go to the PJM market for their ancillary service requirements, experienced the blow out, and now should not be allowed to pass that on to the customer. I think it's a novel idea. I'm very interested to see how it goes forward. All eyes will be on the Pennsylvania Commission on how they rule on this. So I just point that out, because I'm pointing out that there may be very little hedgeability around these products. Someone's pointing out, well, it's theoretically possible, and it's within management's control to do so, and therefore they should not be able to pass these costs on directly to the customer, but they should absorb them. I think it's an interesting debate point.

Having said all of this about theory versus reality, and maybe even sounding like I'm saying it's not very realistic, it's still better to have clearing prices. They are transparent, and they can be used as a tool for indicative future pricing for customers. It's always better to be able to point to something. It's always better to educate your customer on potential prices, and point to an index. As I started out by saying, my hat is off to PJM. It doesn't mean we're not going try and hold their feet to the fire.

So here goes. [LAUGHTER] One of the questions that comes up for load serving entities, and I think Speaker 1 was great for pointing this out, is what we can see and what we're blind to. I mean, no one dislikes a black box more than

us. So when you have blowouts, it naturally challenges your confidence in the market. And when you seek explanations, I think the process you should picture is not one in which a load serving entity, or even a generator, or any sector within the ISO, asks a question, and the professional ISO/RTO staff say, "Here is our answer." It's an iterative process. It's an evolution of understanding that is frustrating. Sometimes there is no good answer, and you have to bang your shoe on the table until you get an answer. And then sometimes that answer evolves, and you get a different answer. That process is challenging while you have the other phone ringing, and customers are screaming, "Where is my bill?" Well, you held the bill, because you want to make sure the charges are right before you make them fall out of their seat with it, and you don't have answers. It's difficult, and it's challenging.

So there is definitely a disconnect between a load serving entity's interest in getting answers and an ISO/RTO's ability to give an answer on the scale and pace that we need those answers. Another small point is that adjustments, whether they're material or not, are disconcerting. Speaker 1 referenced certain software inaccuracies that led to an overestimation of certain generation that needed to be dispatched. With regard to the January blowout in balancing operating reserves, there was also a reallocation from what was RTO-east reliability charges to RTO-wide, and basically if you had a bigger book of business in the West than the East, you just saw a lot of money shift to you. If you had a bigger book of retail in the East, you saved money. But just the fact that you have this number, and all of a sudden...and I'll just throw out the number. It was about \$586 million to the market for uplift. I'm not talking about the cost to the market for paying LMP, which was very high, just uplift. So \$586 million ended up being \$555 million. Even though someone might say, "I'm glad it went down," why did it change? What was inaccurate in the first place?

Allocation from East to RTO-wide based on it being a 340 Kv line.

Those are disconcerting elements, because you really do have to have a price that you can pass on to a customer or reflect in future indicative pricing. These kinds of adjustments, whether they're material or not, add to the lack of confidence in the market and are disconcerting. The January blowout in balancing operating reserves in PJM wasn't the only example, and I'll just take a second to give another example here. This was a 2013 reactive service price spike, which was an experience the community of load serving entities had with reactive service costs. In December of 2012, PJM, in its attempt to get more granular with cost causation, moved reactive services out of balancing operating reserves and moved to more zonal allocation. In theory, that's a great concept. But immediately we saw a blowout in reactive service prices starting in January of 2013. And the question always is, is this temporary? Is this an anomaly? Or is this the new normal? Because all we want to do is be able to reflect prices in products we offer customers and explain it to them. This is an example of the kind of iterative evolution of an answer that we experienced. We were told to keep an eye on planned outages. That's out there. That's reported. Keep an eye on planned outages, because if you have a better sense of where the outages might be, you'll have a better sense of where the reactive spikes might be. We were told that at the same time that we're supposed to keep an eye on outages, the real time voltage problems caused by outages are not something that can be modeled in day-ahead. So we were a little confused. Even if we kind of could predict where the outages and voltage control problems were going to be, we were just kind of told that there's a modeling problem with actually baking that into a day-ahead estimation. Then the subject came up, and I think it was a fruitful one, that here are certain units called "frequently mitigated units," and after a certain number of mitigations down to their cost curve, they get to add dollars to their

bids and recoup more money. Maybe there were more frequently mitigated units providing reactive service at higher prices. We were then told to consider that there were retirements leading to more expensive units not providing voltage control in place of the less expensive units prior to the retirements. That happened over a period of January through December. It was at times frustrating. It was at times difficult. At times it felt like it required banging your head against the wall to get attention. And then on December 24th, I call it the day of magic, something happened. They called it flexible unit dispatch approach. I'm being facetious, but I want to say, I really appreciate that it did happen. Overnight, reactive charges disappeared. So after a blowout in reactive service for an entire 12 month period, with tremendous costs to load serving entities, whether they could pass it on to their customers or not, questions about, is it normal or anomalous, questions about what's causing it, somehow through the evolution of understanding the market, they figured it out and were grateful. But on December 24th, it was quite a gift [LAUGHTER].

And so all of a sudden you have the new normal, which is back to the way you like it, but you wonder how come you just went through the 12 months you did? And this goes to the point of confidence in the market.

Cost causation. This is a tough subject, because, focusing just on the January blowout, reliability-related costs are allocated to all megawatts and cannot be avoided by a load serving entity. If you have megawatts that flow in real time, you will be allocated a portion of the blowout. It was about \$380 million for reliability. Deviations accounted for about one third of the total at about \$170 million. These numbers are approximate. That can be managed, and imagine being a load serving entity that's very tightly scheduled and highly managed. So you've done everything right. You're still facing \$380 million in uplift just for being there. And you don't

understand why. You didn't see it coming. And it's very difficult to pin down an explanation while the house is on fire. It's very difficult.

I think it's worth pointing out when you talk about allocation, one question has to do with customers versus load serving entities. I think there's a common perception that a load serving entity represents the interests of the customer. And I don't think there's anything wrong with that. I think in many cases there are common goals. But there's also a bottom line. So should the allocation be directly to customers? I mean, directly to customers, not to load serving entities, who then have to figure out their contracts with customers, consider invoking change in law provisions, change in regulation, material change provisions, or eat it? If you're renewing a big customer, nothing kills that renewal better than passing on a giant bill that they didn't expect. So, are you supposed to just absorb it and renew the customer? So I think it's worth point out that I'm not trying to say, "Let's throw the customer under the bus, and we'd be fine with everything as long as they pay directly." But I think it's worth pointing out, because we do have the interface with the ISO. We do manage their risk. We do bill them. But some of this feels a little unfair in that we are being given something to manage that we didn't predict or cause and that we may not know how to pass on. So in many cases the load serving entity community absorbed the \$550 million, and, like I said, the one entity that tried to pass it on quite publicly is catching hell for it. So that's a difficult position to be in. If you've read the press, there are six states that are now investigating the retail market, and I just read that the Illinois Commerce Commission has been asked to investigate retail markets by the City of Chicago and by CUB (the Citizens Utility Board). So that could be number seven. We don't know how that's going to go. But clearly the ire of the press and of regulators are on load serving entities. And you're going to have certain channels of marketing shutdown or restricted. You're going to have certain products

that are offered cut down or restricted. And I'm not commenting on whether that's right or wrong. I mean, there might be some good points to reopening this discussion on the ability of a residential customer to manage a real time hourly price. But it seems like the focus is on the load serving entity as the bad actor, when, for the most part, I've seen very good actors within the community.

Coming to the end of my presentation, I wanted to just talk about some of the fundamental market structures that applied during the January cost spike, and this is the basic stuff, and how you can kind of look for solutions when you identify this. We had "conservative grid operations," and I think what that euphemism means is, we inaccurately or over committed certain generation. I think that's a fair way to describe it. We had historical levels of generator forced outages. We had what is being described as inadequate gas infrastructure. I think you can just consider it as fuel storage and fuel delivery interruptions on a great scale. We had transmission constraints. We had unprecedented extended cold weather. Those don't happen frequently, but this was a perfect storm in January, and it happened in PJM.

I think it begs the question of what is the price of reliability. A lot of people will say that reliability is priceless. And there is an argument to be made. But when you look at the kind of costs that were incurred in January, you start to feel what priceless means, and you start to question how priceless is priceless. [LAUGHTER]

Do we have the right mix of generator capabilities? I think PJM is looking for something that might solve the problem if January came again. Is the answer firm gas? Is it dual fuel? We'll wait and see. I think right now you might have concluded that it's dual fuel, and I think other ISOs are looking to provide incentives for existing combustion turbines to put backup oil in place. Is the answer more LNG

storage? People are questioning whether we need pipelines. None of these are answers that fix things tomorrow. They are forward-looking answers. But it's a good question about the right mix.

And then, do we have the right incentives for generators to be available during critical grid needs? As a load serving entity, any new incentive is a cost to me. But if I'm looking forward, and I want predictable, visible costs, I would much rather have an incentive that I see, even if it's a new cost, that I can price into a deal with a retail customer, then not have it, and then have a blowout undermine my ability to make my business work.

I think these three questions about the price of reliability, and whether we have the right mix of generator capabilities, and whether we have the right incentives, all fall under a category of questions about higher reserve margins versus lower reserve margins. I think Speaker 1 used the term "leaner dispatch," but are we supposed to have a tighter market? Are we supposed to have a tighter market with lower reserve margins that cost less over time, but might be susceptible to scarcity pricing spikes at different intervals? Or are we supposed to have high reserve margins that cost more over time? But then, on top of that, you have a January event, and it's quite puzzling to be a long market--to have high reserve margins relative to maybe what you need. I think PJM typically clears in the 19% to 22% or 24% long range, even though the reserve margin is in the 16% area, historically.

Comment: Around 20%.

Speaker 3: So I think there's a good question about whether our reserve margins are right, and whether we should have tighter reserve margins. And this gets into what the price of reliability is. I think that when you look at fundamental market structure, perfect dispatch is an interesting point to look at. Depending on who you ask, there's a different definition of perfect

dispatch. I mean, if perfect dispatch is a combustion turbine meeting load at the right time, that's one way to meet it, and you might have a very high ranking for perfect dispatch. But it doesn't necessarily reflect the optimal and least cost to the market dispatch. I don't know if it actually incorporates uplift into its calculations and evaluations, but it's hard to hear about perfect dispatch getting such a high rating after a discussion like we've been having around January, where you talk about inaccuracies and the need to get a handle on a blowout situation. I think it raises a question, maybe for another panel, another time, about central station and gas and electric transmission infrastructure, versus distributed energy resources. I know there are some states that are actively pursuing this. I'm thinking of New York right now in its "Reforming the energy vision" docket. But if all the answers are more central stations and more gas and electric transmission infrastructure, then someone's going to say, "At what cost, and are there alternatives that would be more customer-sided?" Obviously Speaker 1 commented on this, and we'd agree. Be less conservative. It seemed like it was an all hands on deck dispatch, and it turns out we didn't need that. I understand there were variables that made it difficult for PJM, and my hat's off to them for keeping the lights on. We do think that was the right move. But operator training might help this situation, and I think PJM recognizes that there were too many kind of conversations between PJM dispatchers and generator operators that could have gone better if there was more operator training.

And I'll just conclude with the thought that reflecting wholesale costs in market clearing prices is a laudable goal, because transparency, predictability and hedgeability are essential to the ability of load serving entities to offer risk managed products and services to retail customers. However, as I see it, and I'll admit this, if reliability is priceless, then clearing prices are not the magic bullet, nor uplift avoidable. I'll take any questions. Thank you.

Speaker 4.

Hi. Since I'm supposed to be the trader on the panel, I should say at least a little bit about the perspective of a trader. I don't think of a trader as a "virtual trader," but rather someone who is a market maker, who engages in hedging. You've all heard of the Volker Rule. Banks are required to trade for clients. They're allowed to hedge. And they are allowed to trade in anticipation of client demand. So it's not that we can't do any of the things that people have done in the past, but there is certainly a focus on market making and trading for clients. So, retailers would be clients. Generators would be clients. Wholesale suppliers that win in the load auctions, would come to us. We don't directly participate in those auctions, but rather serve the entities that win. And for that reason, one of the uplifts that Speaker 1 mentioned in the introduction, the one that relates to FTRs, is of particular interest to us, and I'll focus on that as we go along.

So, right on the first slide, I have a very quick rundown of the different types of uplift. The first one is the "make whole," the "bid cost recovery," the "revenue sufficiency guarantee"--whatever name you want to call it. But this is the stuff that the moderator and Speaker 1 talked about, and all of you know it.

FERC Order 745 payments are a more recent unique example. They sort of had an interesting role last year on September 10th and 11th in PJM, where they created \$23 million of uplift. So I have a particular closeness to them, because we paid those.

Real-time congestion uplift is something that people don't think of, but if you think of organized electricity markets, the two basic components are LMP and instruments that help you hedge against these locational variations, the FTRs. And the other piece of it is that they are multisettlement markets. There's a day-ahead market, and there's a real-time market. In some cases, you have the hour-ahead. And the way

you think of it is, all of these instruments are really linked to day-ahead. People schedule day-ahead. They go buy their hedge. And then things happen in real time. If there's congestion in real time, you might get additional congestion rents, so that's more money to distribute around. In some cases, you can end up creating congestion uplift. That happens when the capacity of the transmission system in real time is less than the capacity of the transmission system in day-ahead. So it's not related to changes in patterns of generation or increases in load, but rather it's related to real-time transmission capacity being less than day-ahead transmission capacity. One reason that happens a lot in PJM is that it's a very big complex system with complicated seams that can be unscheduled or loop flows that are not modeled properly. There can be things like transmission outages. And then, more recently, as Speaker 1 illustrated, PJM can take deliberate actions to address one source of uplift by imposing a closed loop interface, which, by definition, will reduce the transmission capacity in real time relative to day-ahead and then generate the real-time congestion uplift.

So why do we care so much about uplifts? The biggest reason is, they're not hedgeable. So I agree with Speaker 3. It's not that they're not transparent. You know what these things are. It's that it's hard to hedge them. As a trader, we go and trade something and write a contract for someone who calls us for a basis hedge on the presumption that we can go and hedge away that risk ourselves. And there is no active market for going and writing a contract to a client to hedge an uplift, and then be able to offload that risk somewhere. So that's more taking on a risk.

Some recent examples, then, of uplifts. The Polar Vortex. As you know, in January in PJM, we had about \$500 million of uplift. So the January uplift in PJM was roughly approaching the level of all of the prior year, a very, very eye catching number. All of us paid attention to it. I've included here an excerpt from the *State of the Markets*, which shows you that if you look at

the uplift as a percentage of the total billing, it doesn't change very much. So it's not that the uplift suddenly became very big. It's that we had a gas price spike, and it's like you go to the restaurant, and you take two people for dinner, but you don't notice the tip. And when you take 20 people to dinner, they automatically put it in the bill, because it's going to hurt you. [LAUGHTER] Well, maybe it's not a good analogy. But there is a similarity here.

Some other examples. Of course, I'll get into the September 10th and 11th uplift later, in the context of FTRs, but these things are not unique to PJM. We've seen in California ISO similar real-time congestion uplift. It was \$250 million in one year—a very big number.

This is a chart that shows what happened cumulatively to the real-time congestion uplift and the impact of FTR underfunding. You can see that in January of this year, we crossed the one billion dollar mark in terms of cumulative FTR underfunding in PJM. It's a big number if you're a policy maker. By comparison, in 2007 and 2008, we had some FTR traders default in PJM. The magnitude of those defaults was \$85 million. That led to FERC Order 741, which everyone complies with. There's no unsecured credit for FTRs. There's the Office of Certifications. And here we have a problem, which was \$1.4 billion when I last checked, which seems to have gone unnoticed.

To draw comparisons with Speaker 2's presentation on enforcement efforts when people do things that impact an uplift and increase it by a few million dollars, it seems that one part of the FERC is very focused and doing, in my opinion, a very good job (and some would say too good a job, in going after things). And the other part of the FERC, I guess, is busy with things that somehow caused this particular problem to escape them.

The same issue in CAISO in 2012 also became a big problem. This chart is just showing you how

CAISO's real-time congestion offset became \$50 million in one month. But CAISO's response was twofold. They tried to improve their modeling. They have introduced since then 15 minute scheduling with their neighbors—they have a lot of imports, as you know. About 30% of their power comes from outside California. And that has helped. Another thing that they did was, they made an emergency filing at FERC, and they said, "We're just going to change the penalty factors we use on our constraints in real time, so we know we have this infeasibility, but the pricing impact of it we can certainly control by just changing the numbers."

So one of the big differences between PJM and California, just from a governance perspective, is in California ISO, they have (in my view sometimes it's a good thing) the ability to do whatever they want to do. [LAUGHTER] And they don't have a governance structure where people can come and give speeches, but rather everyone has to submit written comments. I used to once upon a time. And the CAISO, I think, says, "These are the best comments." So it's not a democracy. There's no sector rated vote. There are two drivers. The first is, what are the best things to do? And the other is whatever CAISO wants to do. And in this case, they got a handle on it. Discharges became very small. PJM, on the other hand, even had to vote on a change of address recently. [LAUGHTER] Yeah, I insisted that that be put in the minutes, so I could one day write in a book that I was a part of that. [LAUGHTER]

The ATSI (American Transmission Systems International) interface in PJM is the closed loop interface that Speaker 1 showed you already. All of the power flows and all of the lines coming into that region must be less than a certain number. And that number can be anything that PJM wants. So last year, I guess in April, we got an email with the definition of this constraint. And when I used to work at the FERC, it was taught to us that anything that has a material impact on rates, terms and conditions is a tariff

change. I'm generally a fan of PJM, and I, being a technical person, like to always focus on doing the right thing, not what most people want, or what some committee passes, and I said, "If PJM thinks it's a good thing, it probably is a good thing." But this really is very subjective. It says that for price formation purposes, it's not a reliability constraint. There's no reliability reason to keep the flow below a certain number. It's saying that if the prices somehow are not at the right level, or if resources dispatched in the region are not reflected in the price, PJM can impose this constraint and get the price to a high number. So on September 10th and 11th, 1,000 megawatts of demand response was dispatched, and per the rules, the \$1,800 strike price would be eligible to set the LMP if and only if this region was in scarcity condition. And it was not. And there are lots of other reasons for that that we don't, we won't get into here. But PJM said, obviously it's a good thing, then, to try and reflect this in the LMP. Let's impose this constraint. What escaped that analysis was that when you factor in FERC Order 745, the level of uplift is independent of whether demand response resources set price or not. Because if the LMP had been \$100, there would have been a \$1,700 make-whole payment and a \$100 LMP payment, adding up to \$1,800. If you set the price up to \$1,800 by imposing this constraint, there is no make-whole payment, but there is a FERC Order 745 LMP payment of \$1,800. So the total uplift was the same. No gain there, other than making things a little bit more transparent. But because this constraint reduces real-time transmission capacity relative to day-ahead, and it wasn't modeled day-ahead, it created \$23 million of uplift. So PJM, to its credit, understood this, and they haven't done it since, and they've been more careful. We're not an entity that goes and files complaints, but we certainly like to mention it to people when we get the chance. [LAUGHTER]

There are a few other efforts to address uplifts that are ongoing. There is one this summer, equally interesting, which is that PJM has tried

to address out of market commitments made by their operators in anticipation of scarcity on hot and cold days, where they commit resources that are not in the LMP, so they said, "We're going to add 1,300 megawatts of reserves in real time." So this is essentially a price formation constraint. I think it's pretty elegant, but, again, it's one of the examples, material impacts or impact on rates, terms and conditions, and it's sort of a footnote. It wasn't even covered in *Platts*. The market did not move in response to this. But it's a really big deal.

There is the effort in MISO to try and capture some inflexible units in the LMPs, to reflect commitment decisions. So this is the extended LMP and the convex hull pricing. New York ISO has been doing this for a long time, because there are inflexible units in New York City that are committed, and they reflect them in the price. In other parts of the country, like California, the number of inflexible units is much smaller, so it's unclear to me if this approach would have as much of a benefit there. But that's an interesting conversation as well.

Another approach to addressing uplift is using metrics for better dispatch. And this is generally a good thing. PJM has a metric called "perfect dispatch." They rank the operators. I think MISO has a metric such that the bonuses of employees were linked to FTR underfunding, so you don't have FTR underfunding as a result. So all of these metrics are good. [LAUGHTER]

This is a chart that shows at least one of the contributors to uplift, infeasible ARR (auction revenue rights) allocations. So in the Energy Policy Act of 2005, there was a little footnote that load serving entities had to be given long-term FTRs, and in cases where the capacity of the grid was not sufficient to accommodate them, these were still to be allocated, and the grid was supposed to be expanded to then make them feasible. Well, something went wrong in that process, because we now have a routine over allocation of these FTRs in PJM, and you

see here the charts from 2013-14, and then 2014-15, that show you the source-sink paths. It was very interesting to me that the load serving entities that are related to the sinks in these infeasible allocations actually are the ones that have been generally supportive of fixing the problem. And the people who generally resisted are a very different set of people. So, again, it makes PJM a little bit like Washington, if you will.

It was also interesting to me that there was, under Dodd-Frank, an exemption of all the RTO products issued by the CFTC. And that exemption had very specific language on FTRs. It had two items. I only list one of them here, and this one was that the exemption is conditioned on the assumption that the quantity of FTRs will never exceed the physical capacity of the grid. So if PJM has got a billion dollars of infeasibility, this sort of makes it a bit of a joke.

And the recent FERC Order 745 is sort of a caution, I guess, where you had a small glitch that some people said was outside the context of economics, and FERC said, "We don't base our decisions on economics," and then now they're facing a much bigger jurisdictional issue. Well, I would hate to see this one go there and someone take this to the CFTC and say, "Let's cancel the exemption," then PJM becomes a swap dealer, and then we get into all of the things Speaker 2 was talking about. Should these markets even be under FERC's jurisdiction?

Let me just point out this chart that I got from the PJM *State of the Market* report. This shows the percentage of auction revenue rights that are allocated to load serving entities that get converted to FTRs. Over the last four years, they have been declining from the 60% level to the 30% level. What this tells you is that the underfunding of FTRs has made these instruments less attractive as hedging instruments, and people have chosen to just hold onto the money from the FTR auctions as load serving entities, rather than convert them to

hedges. Of course, this doesn't work very well when the conditions in January differ very much from the expectations in the auctions, which is what happens. So then they're not very good hedges. But sometimes I find myself scratching my head when I see in the *State of the Market's* statement that FTRs and ARRs were a perfect hedge and offset 100% of the congestion in the first quarter of this year.

This next chart shows you that references to aggregate underfunding are sometimes a little misleading, because if I knew that FTRs are underfunded at 70%, I could just go and buy more FTRs. If I need to hedge one megawatt, then I go buy two megawatts of FTRs. That would work. It's the unpredictability that's the problem. So, on February 14th, the funding was 30%. September 10th and 11th, it was 0%. And this chart just shows you on an hourly basis the percentage of funding of FTRs. So you basically go all over the place, even though the average is 75%.

What is the purpose, then, of FTRs? Are they a mechanism to distribute congestion rents? So that whatever money is collected from congestion, day-ahead, real time, we just use FTRs to distribute it to all the load serving entities? If that's the objective, PJM's design, in my view, does meet it. And I think this is the perspective that the market monitor took when we had our slight disagreement. If the purpose of FTRs is the regional purpose, which was the financial equivalent of firm transmission service, then they failed miserably, because they're no longer hedges. The hedge effectiveness is unpredictable and is from zero to 100. And the third purpose could be if PJM now starts imposing these real time constraints and things that generate more uplift, and then that relates to the level of underfunding of FTRs, then this could just be a way to speculate on uplift. So I'd just like to highlight the fact the for a speculator, underfunding is not an issue, because he's going to pay less money for an inferior instrument, and when the spread blows out, he can still make

money. For someone who is using it as a hedge, the impact is very different. So I'm with the load serving entities, and with the generators in my use of this instrument, and less with the speculators, which is why I've tried so hard, unsuccessfully, to try and fix this.

When it comes to the issue of the allocation of these costs to traders, as a market designer, I think it's very easy to show that if there is net virtual supply, which causes the commitment of more resources, then there is a clear link, and there should be some cost allocation back to the virtual bids. Otherwise, you'll have a situation where the volume of these transactions keeps growing, the uplift keeps growing, and other people pay for it. So you have to have some predictability. I can understand that. But there has to be a link between cause and effect. But sometimes people, they disagree on what the right link is. Virtual transactions are incs and decs, so virtual supply, virtual demand. We had, more recently, something called "up to" congestion transactions in PJM that have been the subject of discussion. These are matching incs and decs. And if you had no congestion in the system, you would think that they offset, and they have no impact whatsoever on reliability commitment and BOR (balancing operating reserve) charges. But if there's congestion in the system, then there is some impact. What is the actual impact is an empirical question.

So we have two extremes, again. The market monitor, who thinks the cost allocation should be the sum of the incs and the decs, and others, including traders, who want zero cost allocation, and I think the right answer is somewhere in the middle. I will close there. Thank you.

General discussion.

Question 1: My question is for Speaker 1. Back in the day, we were trying to look at these two different markets and say, the goal of the day-ahead market is really to minimize your production cost. And so it's only when you get

to the real-time market, and you're doing clean up, that you're trying to minimize startup and no-load costs. And so I heard things like, "Well, if you have higher clearing prices, you would have higher uplift." And I thought it would be the opposite. If I had higher clearing prices, I would have lower uplift. So I'm just wondering, first of all, did we miss the mark on the theory of how you plan a day-ahead market and get that dispatch versus real time? Because I think I'm hearing you now say you're going to minimize uplift in both markets. And then just if you could talk a little bit about whether, if you have higher clearing prices, you are necessarily seeing lower or higher uplift prices? Or are they not related? And just talk a little bit about where we were, versus what is your reality at this point. Because the miracle day, I don't know if that was luck, or if it was something else. Thank you.

Speaker 1: No, I don't think we missed the mark on the theory of the day-ahead and the real-time. And just to sort of bring everybody else up to speed, PJM has two different objective functions in the day-ahead market clearing versus the real-time market commitment and scheduling. In the day-ahead market, we do minimize production costs across the entire 24 hour period for which we are scheduling. On the unit commitment, we run for a couple of days even beyond the next 24 hour period in order to get an idea as to whether or not we should commit units differently. When we switch to the real-time commitment and scheduling, to the extent that we need to commit more physical resources to perform in real time, we change our objective function to minimize unit commitment costs, which is the startup and no-load that you referred to. And so typically you would see higher marginal prices in real time than you would see day-ahead, if you had additional resources that were actually operating. And the reason to do that is to solidify the incentive to bid in day-ahead. So we recognized from the beginning that capacity resources have an obligation to offer day-ahead. Load does not have an obligation to bid and hedge itself in the day-ahead market. So, again,

to solidify those incentives, that was why we differentiated those two objective functions. And the same thing exists today. What we were recognizing, though, and most of what I was talking about was real-time focused, to get everything that's possible in the price in real time, recognizing to the extent we can model a constraint in both places, we should do the same in day-ahead so that the physical models between the two are as similar as possible, because that's another goal from the standpoint of the market operator, to make sure that the two markets operate as efficiently as possible. But there were times when, for things like black start, we were committing resources in real time, because we needed them for black start, like automatic load rejection units, but we weren't recognizing those commitments in day-ahead, and so we had a physical sort of discontinuity between the two. So we needed to start recognizing those things we knew were going to happen in real time and we needed to start actually doing them day-ahead in order to, again, avoid these systemic mismatches between the two. So those are the kind of things I think maybe you were hearing. Speaker 3 actually made the comment you asked about the higher prices leading to higher uplift, and I have to admit, I'm not sure exactly what that meant, either. So maybe we'll get into that further in the discussion.

Question 2: I wanted to comment on something that Speaker 3 said, where he mentioned, and I don't have the exact words, but it has to do with sort of an ideal mix of generation, and I wanted to suggest that the ideal mix of generation can have many different incarnations, depending on what perspective you're looking at that from, either from the environmental mix, or maximum renewables, or etc. And what hasn't been mentioned in the context of generation is the very real environmental regulatory challenge of constructing what might be considered from an economic or reliability point of view the ideal mix. I mean, it may be coal fired generation. It may be nuclear. It may be combined cycle. It

may be a combination of those things. And it also may include having to have additional gas transmission lines, which have their own set of challenges in terms of getting environmental approvals for rights of way and stuff like that, even though in some regions, like in New England, it's very clear that the need for those additional transfer mechanisms is there. So, Speaker 3, I don't know if you want to elaborate on your perspective of what constitutes an ideal mix or not, and how far away from that we might be, but I think the starting point of this discussion is awfully important, and the so called ideal mix or the current mix is a very important point. Thank you.

Speaker 3: Thank you. I don't think I'm here wearing that hat. But I recognize all the points you just made. I believe that, as PJM has said it, it's better to have some more expensive, let's say, oil fired units for a few hours, than to run gas for 24 hours overall at a higher expense to the market. So I'm not so focused on what the actual proper mix is, but I do think what January showed us, with the interruptions in fuel storage and fuel delivery and with the unprecedented forced outage rates, is that we have a need for something we didn't have. We all of a sudden went from plenty of flexible generation to much less and inflexible. So to the degree that it could result in lower uplift, even though it could be for intervals more expensive generation, but fewer intervals of that more expensive generation, I would support it as a load serving entity. And I'll let Speaker 1 fill in.

Speaker 1: I don't have much to fill in there. I agree with Speaker 3 that, you know, as a system operator, we're after the least cost dispatch. And so if it is cheaper to be able to run a more flexible unit that might have a higher marginal cost for a lesser run time than a unit with a lower marginal cost but a much longer minimum run time, then that's likely the least-cost solution, and we'd rather do that. Now, the key, I think, for the purposes of this discussion, is getting as much as possible into the

transparent price, and as little as possible into the make-whole payments that then need to be allocated as uplift.

Speaker 1: Sure. And I understand that. I would just observe in Speaker 3's comments that it's only relatively recently that the marginal cost of running a gas-fired unit in certain situations is higher than the marginal cost of running an oil-fired unit, because for a very long time, it was the reverse.

Speaker 3: You're referring to a relatively short lived occurrence in January? Or in the longer term?

Speaker 1: I was just thinking about January.

Speaker 3: OK, you were thinking of like a minimum time sort of situation, versus a more flexible situation.

Speaker 2: One additional remark. I fully agree that LMPs should reflect costs, including costs of more inflexible units or units that provide additional benefits. And I just would have to add, too, that LMPs need to be able to be rationalized and hedged through greater volume of transactions, and I again think day-ahead physical transactions, virtual trading, FTRs, all of these other financial products allow greater transparency and price discovery around short term LMPs that also provide benefits because they provide appropriate energy price signals to generators.

Question 3: Thank you. My question goes to Speaker 4 and Speaker 1, but obviously others can chime in. Speaker 4, with respect to your chart on FTR infeasibility--and I don't want to get into anything in the past--but looking forward, it seems to me that when you're looking at transmission upgrades, if it's not a direct reliability problem, it's our old story of the economic transmission line. And do you see a mismatch, and I don't mean this critically, because we're looking in the future, between

what is being seen in real time, including in extreme circumstances, and the planning for economic transmission? And this is not necessarily directed at PJM, but all the RTOs, where you're looking, it seems to me, at a more idealized system, the PROMOD models don't take into account maintenance outages, forced outages and such for expansion planning. And is that in your view part of the solution to the FTR infeasibility problem? Getting the right transmission, but looking at it through a different modeling lens? And again, no criticism intended of what's been done in the past. But we've got new information, you know. How should that be taken into account going forward?

Speaker 4: I think one observation that was made recently on the disconnect between the planning and some of these infeasible allocations is that the allocations are linked to some historic reference, and so there are sources that you nominate, and there are sinks, and there are quantities based on some baseline year. And in many cases, those sources have even retired. So there's even a question about whether you should even be linking those real upgrade decisions to a nomination that is just a situation in which people are just holding onto it as a pot of money. They're not really using it as a hedge. And I made the argument that the conversion rate from ARRs to FTRs has declined significantly, because these things are not effective as hedges anymore. It was brought to my attention by one of my public power friends that the other reason for it is that the historical nominations were linked to some resource which is no longer there. And a lot of the supply resources that people have now through their hedges and other activity are very different. So that's the other reason. They just want to hold on to the money. So it's even questionable to me to be linking major transmission upgrades to some little carve out that was made in some deal that was cut somewhere. It's also useful to mention that there has been one example of a real upgrade that is in the works, I believe, and that's also linked to that highest, most infeasible path.

So I didn't mean to be critical of anything in particular. That was just illustrative.

Moderator: After those two comments, I just want to emphasize, it's part of the ground rules of the Harvard Electricity Policy Group that you're allowed to be critical. [LAUGHTER]

Speaker 1: No offense will be taken. Right? I think the rules we have today, and the triggers for transmission upgrades that stem from the transmission right allocation process were a little more thought out than that. They weren't sort of just a deal cut somewhere. The idea was, the transmission system probably wouldn't change significantly very quickly, and over time would be relatively stable, and therefore, as these transmission rights became infeasible we would plan transmission upgrades for the long term in order to make them feasible in the future. I don't think anyone foresaw the fuel switch that we're seeing today and the level of retirements that are happening today and the new generation that's coming in to replace it. Certainly we didn't foresee that seven or eight years ago when the current process was put in place. So certainly I think it's time to review that and see if it could be improved.

But I think the question was a little broader, and that is, should we be looking at more criteria in the economic planning for whether or not transmission upgrades should be built? And I think the answer is probably yes. I think that process could always be improved. I think it was, or is, the product of the PJM stakeholder process that Speaker 4 likened to a democracy, but the fact of the matter is, the criteria and the assumptions that go into that economic planning process were all sort of approved. We've certainly made changes to the economic planning process recently to make it more of a two year cycle. But certainly I think that it's always open for improvements to see if there are more criteria or different criteria we should be taking account of to see if transmission upgrades would be economically viable.

Speaker 2: One additional support item (and this gets a little granular): other things need to be included in planning, because, as I mentioned earlier, the model is complex. From the enforcement side, as well as the regulatory side, we've seen a lot of degenerative, different types or anomalous pricing results for FTRs based on very specific system conditions that don't necessarily make a tremendous amount of sense. If you look back at, for example, the Deutsche Bank case deep into that enforcement matter, if you look ion the underlying papers, there were a lot of different types and ranges of results that could occur at different points. You know, the source sink nodes for an FTR, that created entirely different and seemingly contrary results, and one would hate to use only that type of information for underfunded FTRs in that instance, or the results of a nodal calculation as the primary driver of transmission upgrade decisions, because, you know, it's a complex model, and sometimes it fails for de-rates that are different in terms of their direction and other types of system constraints that were mentioned. So it might not be also the most reliable price signal for major system upgrades.

Speaker 4: I want to add just one very quick comment. There was a particular line there from Northern Illinois Hub to Cook. There is an ability to do merchant upgrades, so you can actually fund an upgrade, and then you get the long term rates for it. So in terms of anomalies, it was very surprising to me that a recent merchant upgrade should also be in the list of infeasible facilities.

Question 4: Speaker 3 raised the question of the economics of reliability and how much money we should spend for it. And I just will state a proposition and see what the panel thinks. I think that this is ultimately a political question and not an economic question. Maybe it should be an economic question. But the reality is, if rates go up for a couple of days, even substantially, the market can withstand that, and

the people responsible for the market can withstand it. But if somebody makes an economic decision that ends up causing the lights to go out, that's something that will not easily be lived down, and could have substantial long term harm to the marketplace and the institutions that run it. And therefore there's a substantial bias, a natural bias, for system operators to spend more money than might be wise in order to ensure that we don't have the lights going out. Do you guys agree or disagree with that? And is there an answer to it?

Speaker 1: Well, this is why I referred at the very beginning of the panel to uplift as a necessary evil. At the end of the day, when you're talking about real-time operations, the fact of the matter is, you have a human being sitting there in the chair, and, yes, there are several levels of checks and balances on that human being's actions, and you provide the most automated and the most advanced set of tools that that human being utilizes in order to make their reliability decisions. But at the end of the day, it's a human being making the decisions. And that human being never, ever wants to be the one to have decided not to schedule a given resource, and then have load shedding result from it. And that's the constant struggle. Right? That's the constant tension. And the system operators, if they're going to make a mistake, are almost always, and I hope always, going to err on the side of having a little more resources there and running in order to maintain reliability than not having enough. And so, like I said, the fact of the matter is, uplift is always going to be there. And the question is twofold. Number one, how do you minimize it to the greatest extent possible? And then number two, how do you allocate it in a way everybody can live with and in a way that does the least harm in the market, and by virtue of that makes it as efficient as possible for the market participants, again, to serve the end use customer's load at the least possible cost?

Speaker 3: I think the questioner put his finger on the issue very well. And I don't mean to suggest that reliability should not be priceless. I just think, when you have an experience like January, you come out naturally asking the question of, if we're talking about billions versus minutes of shed load--no. Do I want to be the person who sheds load in Chicago for a gas fired heating apartment building? No, not this winter. But you have a natural question of cost to the market. And, I agree, it is a tough decision to make.

I'll give you just a quick example, though, of how people can manage it. We had a large industrial customer that took a complete pass-through product, and what that means is, we just arranged it for them. They took the LMP clearing price, and all ancillaries were passed through. So January was a terrible month for them. They got hit with very high clearing prices and very high uplift. And we went to them, and we said, "Do you want us to change your product to something that's more risk managed, fixed price? You can pay back the January bill over the 12 to 24 months of this new fixed price contract you want to sign with us?" We were surprised by their answer. It was, "No. We're a sophisticated large industrial consumer that anticipates the 100-year storm. We've made more money playing the market than we lost in January, and we'll continue not expecting this to happen tomorrow, and we're prepared for this." That's not a likely outcome for most of the mass market. But it does show that load serving entities, some consumers, ISOs do feel like the right thing is to maintain reliability at any cost, and some feel they can manage it. I will just caution that there are some others, mostly mass market customers, who don't, and this was a real big hit for them.

Question 5: I've got a follow-on question to that benefit of reliability versus cost issue. One of the proposed solutions that FERC has issued as a result of the winter high costs and the uplift was, FERC issued a Notice of Proposed Rulemaking

about the possibility of moving the gas day on the gas pipeline side from 9:00 a.m. to 4:00 a.m., and then also proposed some additional intraday scheduling changes. And that was issued in March, and over May and June, FERC asked the North American Energy Standards Board, NAESB, to have four meetings. And I got the fun of participating in all four of those meetings, since I used to be a pipeline person from way back when, and now I do electricity. So one of the questions that's come up (and this really goes to Speaker 1) is that, of course, changing the gas day in the United States on the interstate pipelines will impact every single gas and electric entity throughout the United States, and all of these people were at these meetings over the course of May. And NAESB is actually going to be filing the transcripts of all the meetings with FERC this week or next week.

One of the things that I'd read in some of the ISO comments, including from PJM, was that one very helpful thing was FERC's issuing the new rule on gas pipeline ISO communications last year, where they opened up the communications, and one of the things that was on Speaker 3's slides was operator training, and that's something PJM's looking at. Do you think it would be helpful, Speaker 1, to have FERC, maybe before making all these changes in scheduling on the gas side, to reopen that docket, or look at that docket, to maybe add better generator communications, so that generators can also participate in those comments? Because I'd read some comments of the ISOs saying that the generators really weren't involved in so many of those discussions between the ISOs and the pipelines, even though they were about their gas-fired generator plants...

Speaker 1: Boy, I'm glad HEPG pays so well for being on these panels, for taking these tough questions. [LAUGHTER] Well, I think, first of all, we certainly stand by those comments we made that opening up the communications between the ISOs and RTOs and the pipelines

was tremendously helpful during the cold weather events of this year. Certainly, where in prior years we may have had real reliability issues with a lack of coordination, I think we can safely say that we were in a much better position as far as knowing where gas supplies would be available and unavailable and what generators would be potentially caught by curtailments and that sort of thing than we ever have been in the past. However, we also know that we have a lot to learn on the economic side. And we think that the FERC NOPR was a move in the right direction as far as getting people talking about whether or not the integration of these entities could be more efficient, if you will. But to answer your question, I think, if I understand it correctly, I think there might be a real confidentiality concern relative to having multiple generators involved in conversations with pipelines and the RTOs. If you're talking about one offs --

Questioner: One offs, yes. My question was really going toward just a conversation between, for example, a Transco, and PJM, and you know, a Calpine plant or something, a particular plant, where you don't get into confidentiality issues. And I think there were some comments by some of the plants saying that there had been questions, things happening between the pipes and the RTOs' conversations, and then where they would have had valuable input on, could their plant even run right then, that kind of thing. So it wouldn't be amongst multiple generators.

Speaker 1: Right. Well, certainly, if what we're talking about is opening the lines of communication even further, to the extent that we do not tread on any confidentiality issues, certainly I don't think that that's a bad idea. In fact, I think it can only help things even more. If what's happening now is one-off conversations between the RTO and a generator, and then the RTO and the pipeline, and then the generator and the pipeline, it will be more efficient to get all three on the phone at the same time. That seems pretty obviously to me, and I don't see

why we wouldn't be able to go there. Does that answer your question?

Questioner: Yes.

Question 6: PJM periodically reviews uplift in other RTO/ISO organizations, where they are, just to see where they are and how they match up. And given the growing concern among the load serving entities that uplift becomes a larger and larger percentage, the portion of the bill that's very difficult to hedge, what has PJM learned about the question of the relative size of uplift, the degree of granularity that's provided in terms of the components of the uplift, and what long-term allocation of items that are currently in uplift there is that might be reallocated in other portions of the billing and settlements? Are there any messages you've gotten over the last year or two based on looking at how the uplift is being dealt with in other markets?

Speaker 1: It's a good question. I think we can always learn things from coordinating with and studying how our neighbors handle these issues. But I think if we've gained anything from doing that analysis, I think it's kind of a reinforcement of the kinds of things we've talked about today, where you can sort of divide up the categories of uplift in different ways, and I think the ISOs and RTOs do that. The fact of the matter is, it's still uplift. And I think we're all maybe attacking it in a little bit different ways, in terms of mechanisms to minimize the uplift. I think it was mentioned, you know, MISO's moving to the ELMP (extended locational marginal pricing) later this year. We, frankly, at PJM have a bit of discomfort, you know, with that approach. But we do recognize that we needed to do better in getting more into the price by virtue of the inflexible resources that we're now having to operate that we have not had to operate in the past, and getting those things into the LMP. So I think really we're all marching with the same objectives as far as minimizing these costs and then looking at the best way to allocate them.

But I'm not sure we're all going to end up in exactly the same place. And I don't know that I have a better answer to your question as far as anything specific we're learned from surrounding RTOs.

Speaker 2: I think it was an interesting question. If I could add on to the answer, New York ISO (I think I have this right) allows a generator to update its real-time price curve if it's switching to a more expensive fuel, like a natural gas-fired plant that has oil as backup. I'm not saying that that's been vetted or discussed, but in that kind of situation, you'd obviously have to make sure you protect against gaming. But that kind of an idea is being looked at by New York ISO and implemented. So you do have different ISOs implementing different things. And with all sympathy to PJM, I really do think a perfect storm is what happened. New York didn't have the rates of forced outages that PJM did, and PJM is really looking hard at how to ensure that if this were to happen again, maybe there's more testing and other elements. So there just were some situational differences between the other ISOs, at least vis-à-vis January, that didn't put them in the same bind. So it's not necessarily analogous. But there are some things, like updating prices for different fuels, to consider.

Speaker 1: And that's along with a lot of other ideas are being sort of injected into the PJM stakeholder process at this point. And getting through all those in a relatively short timeframe is going to be the challenge.

Speaker 3: Can I just take this up really quickly? I'm wearing a load serving entity hat here, and I'm trying to represent the discussions I've heard among the community. But I think it's still worth saying that uplift is not necessarily an evil. It supports reliability. I mean, I think that's just true, and it has to be recognized. What I mean by that is, even though clearing prices, I'll use the term, are the Holy Grail of a theoretically efficient market that sends the right signals for the cost of consumption and

generation and gives everyone the incentive to either curtail or build either way on both sides, load and supply, I don't think the ISOs and RTOs should try to create a product for everything they have.

I'll give an example. We as a company also own generation. And we have some combustion turbines that are on two hour notice. There's no such thing in PJM as a two hour non-sync reserve product. It doesn't exist. But it is something PJM knows it has, in terms of the capability of its fleet, where it can dispatch generation to meet reliability needs. That's part of the flexibility you want an ISO to have, to be able to use its generation assets to meet the timely requirements. Obviously we're focusing on reflecting that as best possible in clearing prices, because that sends the right signal to both generation and load and minimizing uplift. But to the degree that you can't model everything in day-ahead, despite your best efforts and best intentions, you are going to always have a situation where the ISO looks to its fleet, realizes that fleet's flexibility, and dispatches it appropriately. But any time you have a deviation between day-ahead and real-time, you have uplift. So I do want to say that it's important for reliability's sake, and uplift is right now the mechanism for costing that out to the market. So, to some degree, though it might be contrary to what I've been representing, we also, as load serving entities, recognize that. And know that it's not necessarily something that you can get rid of.

Question 7: Speaker 4, in your presentation, under the headline, "Order 745 DR," I think you said there was a \$20 million uplift fee in September. Was that actually economic DR, which is what's coming out of 745? Or was that energy payments to capacity-based emergency DR which has nothing to do with Order 745?

Speaker 1: I don't think Speaker 4 was referring to either. I think Speaker 4 was referring to the FTR underfunding.

Questioner: No, there was a line in there about 745.

Speaker 4: No, it was an observation related to the fact that when you dispatch DR, you make an LMP-based payment to the DR. That's all that was referencing.

Questioner: OK, in that case, then it's just a clarification that that DR that was dispatched was capacity DR, and those payments may be LMP-based, but it has nothing to do with Order 745. So that heading was just a little bit throwing me off. Thanks.

Question 8: Two comments up front. Great panel. And secondly, Speaker 3, welcome to the load serving entity club. [LAUGHTER] You have two questions in your fundamental market structure slide. The first was, do we have the right mix of generator capability? And the second was, do we have the right incentives for generators to be available during critical grid needs? We kind of put those two together, and I'd like to ask a broader question: do we have the right incentives for both? The reason I say this is because, to us, the polar vortex was a wing shot. Now, take where we are, and fast forward a couple of years. We will have about, what, 40,000 fewer megawatts of coal-fired capacity? We're very concerned about that. And so the question is, do we need some fundamental changes? And if so, what? Because we haven't been able to figure it out. What incentives are needed to get the market to, in a sense, provide, without having to go to these uplift charges for everything? It's a tough question. We have been wrestling with it for quite a while. Do you have any thoughts? Or anybody else? [LAUGHTER]

Speaker 1: It's a great question, and a minute ago I referred to the plethora of issues that have been injected into the PJM stakeholder process as a direct result of the cold weather analysis from January, but, really, we were still working on the hot weather analysis from July and

September as well. So we just sort of threw them all in the same pot. And I could try to tick down the list of things that are under discussion, but it's on both sides of the coin. Right? So it's incentives for resources to perform when they're needed. Right? So a 22% forced outage rate on January 7th—that was unthinkable until January 7th. Right? And we can't let that happen again. So how do we put processes in place where we have operational procedures to make sure that resources are as tested as they can possibly be, recognizing you can't simulate 20 degrees below zero until it actually happens? How do we put incentives in place in the market structures with corresponding downside? We read with a lot of interest what ISO New England filed and had recently approved by FERC. I'm not saying PJM is going to go as far as a two settlement approach to a capacity market like New England did, but we think we do need some way to recognize and put performance requirements around a high availability of resources.

So all these things are on the table, including other changes to our market structure, like what Speaker 3 said about hourly bidding, and the question about gas/electric coordination, and how do we get out of the situation we were in in January, where generators are telling us four days in advance, "You need to tell me Friday that you need me on Tuesday, and you've got to run me for 48 hours, or I won't be able to get gas..." Those kinds of things. So there's a lot on the table right now. And it's going to take a lot of I think coordinated change to get us in a better place in future winters.

Speaker 2: And to pile on a bit, although I represent parties in the ISO New England performance incentives docket, I just point you to that docket, because it's very interesting in terms of the incentives that are provided there for capacity payments. Generators have a capacity obligation in return for receiving capacity payments. What is their obligation to, if called upon, show up with electric energy and run? I have issues with it. One in particular is

that ISO New England's system does not really allow for, I think, appropriate exemptions when there are factors outside of a generator's control that would not allow them to meet or perform, I suppose, and provide electric energy in real time, following initial orders from the ISO itself—but take a look at that, because as a general matter, and for this audience, it's a very interesting, I think innovative way to reincentivize generators that are receiving capacity payments, to maintain generation, maintain appropriate staffing, look forward, in terms of natural gas and alternative fuel supplies on site or as available. It's a very interesting proceeding. But it's not perfect, and it doesn't always recognize some of the operational realities of generators in real-time conditions, but it is something to look to.

Question 8: I have three questions about PJM related to the FTR market. My first question is, what percent of the transmission capacity do you sell one year in advance? And then my second question is, do you model the same level of transmission detail in the auction as in the day-ahead and the real-time market? And then the last question is, it looks like on the revenue adequacy slide, slide four, that something changed between 2009 and 2011. Was that the source sink nodes that you talked about earlier? Or is there something else that's changing there?

Speaker 1: Well, taking them in order, in the annual FTR auction, PJM sells essentially 100% of the system capability that it reasonably expects to be available during the delivery year, recognizing it is a one snapshot of the entire 12 month period. PJM does have a significant number of transmission outages that are in the model. PJM takes its best estimate, and it's a conservative estimate as far as transfer limits that are put into the model. PJM puts a loop flow approximation in the model—so unscheduled flow that's induced on PJM's system by outside systems. So all that goes into the model, but whatever's left after PJM models all those types of restrictions on transmission capability, 100%

of it gets sold, 25% in each of the four rounds of the annual auction. On your question about the level of detail in the model, PJM uses essentially the same network model in the FTR auction that it then uses in day-ahead that it then uses in the real-time EMS. That is, recognizing, as you go through a year, you have model updates that occur. So by the time you run your FTR auction, and you finish it in early May, there is a network model update that really happens right before the summertime, and so the model evolves after you have that one year snapshot. But it's the same model as what PJM would use in day-ahead and real-time, up until the time where model updates occur. And on your third question, what changed? It seems to be a confluence of factors. It seems to be that there have been an increased number of transmission outages, transmission derates, construction-related transmission outages that have occurred and recurred since that timeframe. PJM has seen an increase in loop flow and unpredictability of loop flow impacts. One contributor to that (just to give you an example, I'm not saying it's the only or the prime contributor, but it's one contributor) is the increase of renewable resources, primarily wind, in some areas of the system that have, like I said, increased the loop flow first of all, but then also increased the unpredictability of that loop flow, because of the intermittent nature of the resources. So it's a combination of a whole lot of things. I'll probably just leave it at that. It's not just one thing that all of a sudden happened, or PJM would probably have been able to address it much better by now.

Question 9: I just had a clarifying question for Speaker 3. You talked about the magical day when 12 months of reactive uplift payments went away. Where did they go? [LAUGHTER]

Speaker 3: To the best of my knowledge, they were no longer dispatched and needed. Whoosh.

Question: Were those your magic hands?

Speaker 1: I can't speak to the entire 12 months. I didn't, frankly, up until Speaker 3 said it a few minutes ago, I haven't seen it as an entire 12 month problem. We did see an increase in reactive costs, certainly, in the second half of 2013. There may have been different causes. But what I referred to earlier where we actually found process and tool changes that we made that actually decreased the conservative nature of the commitments that were being made for reactive transfer constraints, and allowed us to operate more lean with less long term, long, mid run type steam units and more of those combustion turbines that can be turned on and off more quickly, that was sort of the single change that really was made effective that third week in December [UNINTELLIGIBLE].

Questioner: I was wondering if there was an efficiency or if those costs actually still existed, but got put in some other bucket.

Speaker 1: No, it was an efficiency issue.

Speaker 3: I think it was Speaker 1's presentation slide eight that talked about the closed loop interfaces and some of the leaner scheduling, and literally they just stopped dispatching for it.

Speaker 1: Right, we stopped committing those long-term resources for those reactive interfaces, and instead relied on more short-term combustion turbine resources.

Comment: I just want to comment that there seems to be a really big disconnect between what happens in the real-time market and all of these uplift charges, and even what happens from an LMP perspective, and what gets planned from an economic planning perspective. So I would encourage people to look much more carefully at that.

Also, I know that the models are tough. They're complex. And you know, they're difficult, and sometimes they're not very stable. But if you

don't do anything at all, you're assuming a zero value. So do you want to try to assume some value, even if it's conservative, for the benefit of a transmission line? Or are you going to continue assume zero benefit, and in the meantime you've got, what, billions of dollars of uplift charges out there?

Question 10: As the person in charge of the stakeholder process at the California ISO, I want to assure Speaker 4, we never just do what we want. We carefully consider all the comments, especially his. [LAUGHTER] And I also want to emphasize Speaker 1's point that there is this tension between reliability and then just letting the markets run. And if you've ever had the conversation with the shift operator in the control room, you get an entirely different perspective, and it's tough to question their decisions when they do things that result in uplifts.

Speaker 3: But we do it all the time.

Questioner: But I just wanted to bring kind of another perspective. You know, in California, we have really aggressive renewable energy goals, and we're getting a lot of renewables coming online. And particularly solar has a big effect on LMPs during the day, where our LMPs go very low in the middle of the day, because in the middle of the day, we have large amounts of solar production, but then we also have a big need for ramping to peaks in the morning and the evening, and, because of our generation mix, we have a number of places where we need to depend on longer-running units, and so we've got to keep units online all day to meet the morning and the afternoon ramps, and those units are frequently uneconomic in the middle of the day, so it results in uplifts.

So we've been under pressure to incorporate min load costs into LMPs (something like MISO), but we're not sure that that's the right answer, because incorporating min load costs into LMPs, would then raise the LMPs in the middle of the

day, where in the middle of the day we're dealing with over generation, and high LMPs in the middle of the day would send the exact wrong signal to decrement generation and to export generation. So, especially with renewables, where the costs are no longer in the markets, they're offering at zero or negative prices, the LMP may no longer be the full answer to pricing, I guess, and it's going to make it a lot more difficult to get away from uplifts.

Speaker 4: One thing I wanted to add was that there is a principle that prices should always reflect dispatch. But there's a little caveat to that. If the operators make the wrong decision, they over commit. Say they're anticipating certain thing, and those things don't happen. The load doesn't materialize. In those instances, if you go and then make the LMP and real time reflect those actions, I would think that it creates operational problems, because then you don't need more energy. You've already got too much energy. And I think that the example you gave is just another form of that issue.

Speaker 1: One thought there. Speaker 4, you had commented on PJM's proposal with respect to increasing the reserve requirement. We're proposing only to do it during really stressed or anticipated stressed system conditions--hot weather alerts, cold weather alerts. But maybe that's something to think about as California works through its issues, as well as considering what you keep on line as a reserve product or something to that effect. Just a thought.

Moderator: Just amending the answers to the questions here, in the extended LMP, ELMP world, one of the characteristics of that, minimizing the uplift story and calculating the prices, is that it applies both to situations where you have the right answer and where you have the wrong answer. So if you've overcommitted, you can show that, as long as you're using the right model to calculate the prices. But if they've committed too much capacity because of

operator decisions and so forth, it actually doesn't affect the ELMPs. It just increases the uplift. But that also happens to be the minimum uplift, given where you are. And so it actually doesn't create this problem, I think. That's just important to note.

Speaker 3: I feel like I've become the virtual trading proponent here, but I do have to mention that in these conditions, virtual trading does provide a hedging benefit or an anticipatory benefit to load generation and also speculators that could adjust by taking a day-ahead position and settling it in real time, so that having that type of financial instrument might have a somewhat smoothing effect, or at least offer a hedging opportunity when it's wrong or it's right, and there is some price anomaly because of extended LMPs and that sort of thing.

Question 11: Is the bulk of this uplift problem really the fact that in most of the RTOs, you're mitigating real time prices with bid caps that are too low?

In other words, you're creating, you're requiring an operator to do things that the market might otherwise be doing, if units could bid in price that reflected the real cost.

I'm thinking, for example, of the problem in New England during the polar vortex, where gas hit a particular price, and you had a low bid cap, and you would have forced generators to run at a loss.

Speaker 1: And that happened to some degree in PJM during the polar vortex and the cold weather, the winter storm events later in the month. There is an outstanding FERC case right now where Duke filed for recovery of not so much those types of costs, but other types of losses from the standpoint of that gas versus electric problem. But I don't think that bit us so much during the cold weather, although in general I would say, if the market was less mitigated, and so the marginal resource was

setting price at a higher value, then the intramarginal results from other resources would tend to reduce uplift, I guess, all things being equal...You looked really funny when I said that.

Speaker 2: Yes, I mean, conceptually, I just actually reviewed a paper on this topic, and I think that's right conceptually. If LMPs, real time, are allowed to reflect the true unit, no matter what its capability is, however inflexible, that's setting LMP, and it's above a cap of \$1,000, in theory that should be reducing uplift, because it's allowing for the recovery of costs that are sometimes attributed to uplift, and also to out-of-market instruction to those generators. So it's a very good question, and pretty thought provoking.

Speaker 4: I'm not aware that much of mitigation being the issue, but rather the bid cap or the bid caps. So mitigation doesn't usually mitigate you below your costs. But in the polar vortex, costs and gas prices were so high in PJM that the \$1,000 cap was not enough. The other example is when CAISO started with MRTU (Market Redesign and Technology Upgrade), we had something called exceptional dispatch. So there were a lot of out-of-market things done in real time that were not in the models. The operators just had to go and do things. Over time, that went away, but then it became a situation with a lot of units at min output, so they're not eligible to set LMP. So still an uplift.

Speaker 3: I think that is a very provocative question, and I think that what happened in PJM might be an interesting illustration of it. As I understand it, a generator really does have to bid, if it expects to run on gas, the cost of replacing that gas in real time, and that's where the unknown comes in. And what we saw in PJM (and correct me if I get this wrong) was that generators were allowed by FERC to recover costs above the \$1,000--so not the bid cap of 1,000, but recover the costs above 1,000. When all was said and done, and those

companies came in, it was \$9,000 to the entire market for costs above \$1,000 to be recovered. And I think, although some might disagree with how that number was measured and whether there was kind of a shame factor to come forward that dissuaded some companies from coming forward, I think what you're highlighting and what I'm using this illustration to highlight is, bidding day-ahead on replacement gas costs and actual costs incurred if you can get gas in real time can be very different and reflect, I think, when PJM made the filing to FERC asking for the ability to allow for cost recovery above \$1,000, you used a statistic like there were like 4,000 megawatts that bid right at the cap as some reflection that cost might really be way above the cap. But then it turned out to be \$9,000 to the market. So I think what you're point to is something that maybe will fall under the gas/electric coordination effort, which is a generator that reasonably bids in day-ahead based on replacement costs of their fuel, might not actually incur those costs, but it is quite prudent for them to bid that way for risk management purposes.

Speaker 1: Let me just emphasize very quickly that during the polar vortex and the events of January, the effects of the \$1,000 bid cap were not large. The \$9,000 is what the market monitor filed in its report to FERC, and it is what we actually billed. I don't know whether that was the real number or not, given all the issues that Speaker 3 went through. But even after we got approval from FERC to allow generators to include cost above \$1,000 in their cost-based offers, we never had to actually have that happen. So I just don't want to leave anyone with the impression that that was a significant driver behind the uplift we saw in January. It wasn't. The driver behind the uplift in January was that we just had more resources running at extremely high gas prices than we really needed, and so the LMPs were not compensatory for their actual operation. That was the driver of the uplift in January.

Questioner: But one of the problems was, your forced outage rate, if I understand it.

Speaker 1: Yes.

Questioner: So if you had units that had an obligation, and the price had allowed them to cover their costs, would that have been an incremental incentive to?

Speaker 1: It may have been. And I think you're getting at some of the answers to the question, which have to do with the performance incentives and availability and those sorts of things, and the kinds of things that New England just filed and had approved as well. And interestingly, on the day when we had the 22% forced outage rate, we also had really high LMPs, and that was actually one of the lower uplift days of the entire month. So January was a tale of two months in one, because the first half of the month, we had the polar vortex, and that would have been a high absolute dollar uplift month in and of itself, but as a percentage of total billing, it would have been very small. It was the second half of the month, where the operators had experience, now, with a 22% forced outage rate, the uncertainty of a load forecast, a gas market that was blowing through the roof, and the unavailability of gas. Right? The second two weeks of January were far worse from an uplift perspective than the first two weeks of January, and that was, like I said, a function of all that stuff Speaker 3 called a perfect storm. I'd agree with that. All that stuff coming together that just resulted in us having far more generation operating at far more times than we really needed it to operate, and we had to make it whole, because it was operating at PJM's direction. And he had to make it whole to a very high price, because the natural gas prices were so high.

Speaker 3: And this might seem uncharacteristic, and not that PJM needs any defending, but in defense of PJM, we haven't mentioned imports.

Now, I mean, I think there's nothing wrong with neighboring markets importing back and forth with appropriate price signals, but, to PJM's credit, it did everything it could, but in many instances found itself by midmorning dealing with an influx of massive megawatts that disrupted all the perfectly planned megawatts it had just dispatched, creating excess, and in some cases interfering with the dispatch it had planned earlier that morning. That's something that I don't know how you get a handle on, but I wouldn't exactly lay that blame at the foot of the ISO.

Question 12: It seems that for some dimension of the uplift problems we're talking about, the underlying problem is derived in some part from resource flexibility constraints. And I'm considering flexibility in a very broad sense. In New England and PJM, there were particular discussions with respect to gas interruptions and the firmness of that supply. In California there are discussions about whether or not there are enough flexible resources, given the ramps as you expand solar. And there's a point in this discussion where it feels a little bit like what often happens in these markets, which is, we're fighting brush fires. We identify a problem, and we kind of change the way the market's run to address that problem, and then we're kind of waiting for the next one.

And I guess I want to point to the ISO New England filing, the pay-for-performance filing, as one attempt to kind of get around that. And so the idea of this is to really create, largely through scarcity pricing, the right signals to have resources that provide the right degree of flexibility, and where the risks are allocated in that way. Now, introducing more scarcity pricing obviously involves broader tradeoffs in terms of the markets and where stakeholders are with respect to things like market power, etc. But I just wanted to get the panel's sense of whether there are other options for providing broader incentives for performance. Scarcity

pricing's one, but are there others that can at least kind of mitigate it to some extent?

Speaker 3: From a load serving entity perspective, to the degree that there's scarcity pricing (in PJM you've got certain penalty factors that will take the \$1,000 bid cap and bring it up considerably higher in those intervals) it's a pricing signal, and it allows us to do what we're asked to do, be risk managers. So I think the load serving entity community would welcome scarcity pricing or incentives for certain performance under scarcity conditions, because it's not necessarily going to flow into uplift. So I think, from a load serving entity's perspective, we'd welcome it. Obviously, it's additional cost, but it is manageable as a risk manager if you know the conditions, and you can hedge with super peakers for certain conditions, etc. So we would welcome it, and I think I've got that right from a load serving entity's perspective. It about visibility, predictability, hedgeability. So it would fit.

Speaker 1: Yes, and from the RTO's perspective, I'll just mention that we have seen and been concerned about a reduction in flexibility being offered to the RTO by the physical resources subject to the dispatch. So we put a survey out to our operations folks, our system operation subcommittee, I don't know, six months ago now, beginning of the year sometime, as to, you know, if you used to offer flexibility and you're not now, why not, and if you could offer additional flexibility and you're not, why not? And we basically got two responses back. Not two single responses, just two categories of responses. [LAUGHTER] And the minority of those responses is, "Well, I just don't see the financial benefit. I don't see the cost benefit, or I'm not going to get paid enough, essentially, for offering additional flexibility." So that was a couple of the responses. And we are looking very closely at that to see, is there more we can do? Maybe that gets into scarcity shortage pricing, that type of stuff. I'm not sure. But the higher level of responses really was,

"I'm restricted by my fuel source. I have inflexible fuel procurement capabilities. I have gas restrictions," and that sort of stuff. That was really the other response. And that's why we're

focused so hard, I think, in addition to the events we saw in January, on seeing how we can make that relationship more efficient.

Session Two.

Regulating Generation: When do Wholesale and Retail Generation Become Part of the Same Whole?

The dramatic increase in the amount of distributed generation, the re-emergence of PURPA QF facilities with its associated calculation of avoided costs, the enactment of RPS standards in many states, and the creation of a demand response market, raise the fundamental question of whether the traditional distinctions between retail and wholesale markets are still valid. Are these two heretofore separate markets converging? If so, what are the legal, jurisdictional, and policy implications? If they are not full converging, how do we deal with the effects that one market has on the other. We have already seen recent disputes between state and federal regulators on PURPA requirements, on jurisdiction over demand side response, and even on renewable energy matters. Are these disputes harbingers of more debates to come and where are we headed in terms of both jurisdiction and of policy/market rules coherence?

Moderator: Welcome back for the afternoon session. What we're going to be looking at this afternoon is the question about who regulates generation in terms of some of the disputes that are going on about the line between what's wholesale and what's retail. And there are two kinds of controversies that have arisen, one of which strikes those of us who have been around for a while as a little twisted, and that is on PURPA and some of the issues that FERC has made on PURPA, which appear to be reversing Martha Hesse's decisions of 30 years ago, and the roles between the states and the FERC seem to have reversed themselves. But they have certainly raised questions about avoided costs and how you calculate them and who has jurisdiction. But you have a similar issue in regard to retail or distributed generation. Is that a subject for state regulation or for federal regulation? This is not too different than what we were talking about in regard to demand response.

Speaker 1.

Thank you. As a little brief background, let me start with a little about ERCOT. ERCOT is not synchronously connected with any other grid. There are only five DC ties that range from 36 to 600 megawatts in capacity, although there are projects that are underway to actually add a significant amount of additional capacity through ties. It covers about $\frac{3}{4}$ of the state and

about 85% of the load in Texas, a little over 41,000 miles of transmission lines, and is something over 550 power stations. There are over 1,100 market participants in ERCOT, including over 400 QSEs, Qualified Scheduling Entities. They're the ones that actually schedule power in ERCOT. Over 98% of the power now in the wholesale market is settled in 15 minute intervals, either through AMI meters or IDR meters, and as of June, our loads will be able to bid into SCED (Security Constrained Economic Dispatch), although it hadn't begun yet. We expect as many as three to begin bidding by the end of the month. We have 115 retail electric providers (REPs) in the competitive space, although not all of them serve residential customers. Right now, I believe, in the Encore area of Texas, one of our distributions utilities, there are 45 or so REPs that are offering programs or contracts on the commission's Power to Choose webpage. But you don't have to be on the Power to Choose webpage. There are a lot of REPs who don't, and there are other private web pages that you can go to to buy your electricity.

It's important to know that in ERCOT the market was actually designed from day one as a total whole, and the distinction between wholesale and retail almost doesn't exist. It was conceived as one functioning market. And while I thought that you might rely on my word for it, I thought that having a good New Englander

back up my statement would add to my credibility. And therefore my presentation cites Dr. Tierney on this.

Unlike most of the other markets, or at least RTOs, ERCOT actually has retail responsibility in addition to managing both the grid and the wholesale market. All the meter reads that are taken by the distribution utilities are then sent to ERCOT and then ERCOT conveys the data to the appropriate retail electric provider. They also manage the switching process (between REPs), which is fairly complex, because under our rules now, if you have an AMI meter, you have same day switching, and I have always thought that over time one of the interesting developments might well be that you'd have customers out there day trading their electricity, or at least weekly trading their electricity, and I'm not sure that's developed yet, but there's no real impediment to that happening in our competitive market.

Getting into the heart of this topic and background, I'm going to talk a little bit about the role of DG in ERCOT and how we think about it, as well as the role of demand response, or, really, I view it as load participation on a lot of levels. For example, on the cogen side, you have about 4,700 gigawatts that are currently expected to be available to ERCOT for private use networks, the PUNs. That's the cogen piece. According to the Energy Information Agency, ERCOT has 15,000 megawatts of either cogen or combined heat and power, and out of that, ERCOT usually expects or plans for at least 4,700 gigawatts when prices indicate. Our system-wide offer cap is \$9,000 a megawatt hour, and there is some expectation that that number is liable to increase. However, I have to confess that, frankly, at this stage, there's limited transparency into how much DR is on the system in ERCOT, and there's even the question of how it's defined. The only clear-cut point is that if you have a unit that is less than ten megawatts, you're treated as distributed generation. But the truth of the matter is, we

have units in ERCOT...I know one developer, for example, who has over 150 megawatts around the state, and he connects on the distribution system at more than 15 or 16 locations. I'm actually masking that a bit so you don't know who it is, to keep it confidential. And the way they do this is that they have diesel powered units, about 500 Kw each, and he puts them together in 9 ½ megawatt stations and connects, and then bids into the emergency response service in ERCOT. There are other market participants that do the same thing on a little bit smaller scale. And so that's one level of DG.

Then the other side is the more traditional, rooftop solar, windmills. There's even a fair amount of gas generation that's mostly backup, but I've always been concerned that we don't really have a good handle on how much. I know that after Hurricane Ike down in the Houston area, it became clear that more folks than they realized had gas backup. And so they literally had to treat the center point and put people with the trucks from out of state going around to make sure those crews were treating the downed power lines as hot, until they were sure that they weren't. And with expansion of rooftop solar, that problem is only going to get worse. ERCOT is trying to get a handle on it, just like they're in the process of doing with respect to DR, but it's a bit of a challenge, not the least because we're in Texas, and so people, even if you tell them they've got to register, they don't.

Currently on the DR side in ERCOT, there's really two categories of DR. There are the traditional services that are used as reserve service or ancillary service in ERCOT. We've got around 2,000 megawatts of that between the emergency response service and the load responsive service (LRS), which are mostly the industrials. What is interesting is the development of price responsive loads. The Brattle Group in their 2012 report to the Commission dealing with resource adequacy actually estimated that during the August, 2011,

scarcity events, that perhaps as much as 1,700 megawatts responded to the price signal, and they also noted in the report that they believed that was a conservative number. Until last summer, ERCOT really didn't have any handle over the scope of that fact.

As I indicated earlier, as of June 1, loads can bid into SCED. And then, finally, in a recent report this month, by Brattle, they estimated that DR could grow in ERCOT an additional 2,300 megawatts, to as much as 3,800 megawatts, depending upon programs that were put in place.

And then I have some examples in the slide of some of the, of the products that are being developed by retail electric providers, as well as some of the public power entities, which is another interesting, I think, phenomenon. Because of the threat of high prices, you have retail electric providers now in ERCOT that are very aggressively in the process of trying to get their customers to sign up for load response programs. And the rest are doing it for a lot of reasons. One is that they want to further tie their customers into their business. It's a lot cheaper to keep a customer and renew a customer than to sell to a new customer. For example, Reliant NRG Company, the old spinoff of Houston Power and Light Company. They have a Nest thermostat program. They'll give you a free Nest thermostat if you sign a two year contract, and now, if you have either an AMI meter of any kind, and/or a Nest thermostat as well, they have programs that will pay you up to 80 cents a kilowatt for your reduction when called upon, which is, I think, a really interesting development. There are a number of load shifting programs being offered by REPs, which will have the effect of shifting load off peak, which we are seeing in ERCOT. Then you have the City of San Antonio, which is the state's largest muni. They have an objective eventually of trying to get as much as 700 megawatts under a demand response program. They will use it for a variety of purposes, including trying to monetize it. So this kind of activity over the

years, as we see it develop, will have a definite impact, both on the wholesale market, and ultimately on the retail market as well.

So then this gets into the questions that I've been thinking about in this area. If loads increasingly are participating, if DG becomes more cost effective, how do you deal with it? Do you have to deal with it? It occurred to me when I saw the topic, to ask, well, does it really matter? I can't help but conclude that this distinction between distributed generation and demand response is more than a little artificial, at least in the current context. It's really based on historical developments, rather than a real market.

I think that you've got to think of these issues as one and the same, because if you really want customers to respond, then they or their load serving entities have to get the price signal. That's what encourages the behavior. I've actually had discussions with some experts over the years, who've always raised the point that, "Well, the problem is that you've got to get the retail customer to see the price signal." Well, I'm not sure that's right. I think the experience in ERCOT may be that you've got to make sure that the load serving entity get the price signal, that if they get the price signal, then they have the incentive, and if the prices aren't unduly mitigated, then they have a huge incentive to do all they can to get their customers to respond on command, or when they encourage them. Why? I go back to the reasons. It's not just to get a customer who's stickier, but it's also to use it as a physical hedge against load under forecast. I suspect one of the reasons that Reliant is being so aggressive is because in August, 2011, during the great heat wave, there were some instances where retail providers thought they were fully hedged. It turned out they weren't. And even then, the offer cap, the effective cap on the market was only \$3,000. But even if you're only short a few percentage points, it gets really expensive really quickly. It's the same thing with generation in terms of incenting the right behavior. But it's not just to protect themselves.

It's not just a form of insurance. There's also, if they are fully hedged, the potential to monetize this, and Brattle identified that apparently in conversations with generators, there are actually generators or representatives of generators that have approached load serving entities to buy a call option on their DR program as a hedge, as a form of insurance. So, again, if you create the right incentives in the wholesale market, you can get your retail customers to respond.

Now, we're ahead of the game in Texas, by virtue of the fact that our advanced meters separately measure the inflow and the outflow. In other words, if you put solar panels on your roof, the utility is still measuring all your consumption separately, and then all your production will be measured separately, and assuming that you sign up a contract with a retailer that agrees to buy your output, then it ends up as a credit on your monthly bill. And so we don't, at least, have the problem of how the distribution grid actually gets paid for. It will get paid for. As you saw in the presentation, in Texas the transmission system is paid for by load, 100%. Resources don't pay to access the grid. There are questions about, on the distribution system, where DG connects, what upgrades, if any, have to be made if you really see an explosion of DG. Should the DG producer bear some portion of the cost? The counter argument would be, "Well, shouldn't you treat the distributive generator the same way you treat the transmission level generator, in that they don't pay anything? The grid is a grid. We view it as a highway to facilitate the market." Over time, I don't know how that's going to end up shaking out, but it's a question. But it goes back to whether it's loads responding in the wholesale market, or otherwise, or whether it's distributed generation. The distinction between the retail market, I would submit, and the wholesale market is a pretty artificial one.

Speaker 2.

Well, thanks for inviting me, Ashley, and it's a pleasure to address this group. I have the

distinction of having the shortest slide deck, and it's mainly to facilitate translating the snarky comments I'm going to make orally into a paper record that I might regret. [LAUGHTER] So let's hope I don't end up regretting it too much.

So the title of this next slide comes with a question mark: "Cooperative federalism?" Scott Hempling had a great quote that speaks to the artificiality of the wholesale and retail divide that Speaker 1 just commented on, and he wrote, "The electric industry's federal/state jurisdictional relationship is a product of constitutional bargaining in the 1780s and New Deal legislating in the 1930s. No other nation assigns regulatory authority so disconnectedly from electrical and commercial reality." Here, here. You know, it's supposed to be the role of state regulators to arrogate power unto their jurisdiction. I think we need to understand the legal framework of cooperative federalism that we're in fact working within. Typically it's one where Congress or FERC adopts a law, or implementing regulations for a law, or spontaneously issues an order--manna from Heaven based on FERC's central and fundamental authorities. And then periodically FERC can delegate that power to states.

Quoted here are some of the principle rulings that taken together kind of set forward the basic federalism under which FERC and the states work (though only one of them is in fact about the electric industry). Number one, states can be granted the privilege of regulating something that the federal government has already occupied the field of. In other words, an otherwise pre-empted field can be delegated to states. The federal government can't force states to do it. States, if they want to, can pull a Pontius Pilate washing of the hands move and force the federal government to enforce its own compliance. That's point number two, *Printz v. the United States*. The petitioner in that particular case, Printz, was a county sheriff in Montana who refused to enforce federal gun laws, and the US Supreme Court said, "Yeah,

he's totally within his rights to do it. If you want to do it, FBI, you're going to have to come into the wilds of Southwestern Montana yourself." And then, of course, the third bullet point is a decision with which all of you are familiar, *FERC v. Mississippi*. State agencies can't be conscripted into doing things that are federal mandates. And where is the dividing line between mere inducement or encouragement and conscription? Well, in the finest traditions of Supreme Court jurisprudence, "We know it when we see it." And that was the holding, of course, in the Affordable Care Act review that came down just last year. Holding, in that case that the federal government was unconstitutionally conscripting states into doing something. You'll notice that it's monodirectional here, where the federal government sets authority that states then implement. There are occasional feedback mechanisms the other way.

If anyone has read the greenhouse gas 111(d) proposed rule, the fundamental basis of that rule, which is the federal government setting states' goals, is actually taking building blocks that are derived from state actions. So, for instance, there's a de facto sort of nationwide renewable energy standard for the purpose of creating state goals. Those are based on an average of various state percentages that they apply through renewable energy standards. So in that case, the federal government is sort of taking particular laboratories of democracy that they like, that accomplish their implied goal, aggregating them together, and then re-imposing them as goals on other states. There's a similar thing in the greenhouse gas rule for energy efficiency. EPA sampled 12 states that they view as leaders in demand side management, and said these states' energy efficiency programs are growing 1 1/2% year on year. They took that goal, aggregated it up to the level of the EPA's building blocks that they're using to establish carbon goals, and then again plan to re-impose them on states across the board. So there are some feedback mechanisms, but not many.

There are four things that were mentioned in the topic description: PURPA, distributed generation, demand response, and state RPSes. And I've got one slide for each of them. PURPA's probably the premier, which is not synonymous with best, example of states' regulation of an otherwise pre-empted field. And we've seen a recent resurgence in FERC policing of states' compliance with federal regulations that implement PURPA. And, in particular, there have been a number of complaints under section 210(h) of PURPA--almost all of them, if not all of them, coming from non-RTO environments. I sat back this morning, and I heard so much about PJM--and we bilateral markets, we just hide all of this dead weight under basic cost of service, vertically integrated monopoly regulation, so we don't have to worry about uplift charges.

But for all of you operating in East Coast RTOs, let yourselves be reacquainted with the arcane institution that is PURPA, which has been a hot topic in the West. Basically, for those states that are not exempted under section 210(m) with a 20 megawatt or above exemption for PURPA projects, we still live under an obligation to keep the door open for QFs that unconditionally offer their energy and capacity for sale to utilities which must buy their power at avoided cost. Nearly all of the FERC cases, the declaratory orders, and, in one case, the lawsuit that it filed against the Idaho Public Utility Commission, have revolved around situations where the incumbent monopoly has simply refused to negotiate with these independent power providers, or where the state commission, sometimes in cahoots with representations the utility has made to them, have closed the door. The Montana Commission got sued. Montana had, basically, an arbitrary megawatt ceiling on the amount of wind QFs that it agreed to offer, implicitly arguing that there was no further need for capacity coming from QFs, or really for anything, and then suddenly the utility went out and bilaterally negotiated the purchase of very significant generating assets on its own, that it

itself intended to rate-base--a little dose of hypocrisy that, not surprisingly, resulted in a FERC declaratory order, though they didn't sue.

So the basic line here is that FERC, when states or the utility have drawn a fairly bright line in trying to close the door utterly on PURPA projects, whether in states' too prescriptive readings of what it takes to form a legally enforceable obligation, or arbitrary ceilings on PURPA projects, that's where FERC has really come down and acted, it seems.

In terms of how states have calculated avoided costs, and the methodologies they use, states still seem to be enjoying wide deference on that particular topic. And I would submit that many of the absurd results that have been seen through the implementation of PURPA in the American West really could be placed back on states who have adopted relatively crude avoided cost methodologies that failed to consider and actually price the value of energy in particular places. One example of this had to do with a couple of wind farms connecting on a low voltage, basically radial, circuit in Eastern Oregon where there were no customers, and where it was almost impossible to get that power to load centers, but, nonetheless, that QF was, under Oregon's standard of rate making methodology of PURPA, eligible to avail itself of an avoided cost that clearly didn't reflect an avoided cost of a generating asset built there.

Moving on to distributed generation, first a necessary caveat that this issue gets a huge amount of hype, and some of it's justified, some of it's not. I'm sure that for the Arizona commissioners who have sat through proceedings on this matter, the hype certainly seems justified, because they've been eating, sleeping and breathing this stuff, like, 24/7. And for people who think that distributed generation really is the future, it probably doesn't seem like hype either. But I find it necessary to point out that it's an incredibly small proportion of the energy resource mix of nearly every state. In

Montana, it's de minimus. In most states, it's de minimus. Only in places like California, which have such screwy inclining block rate features, where people are offered avoidance of a full retail rate at that concluding block by hooking up a distributed generator, have these concepts really come into play. That, and, of course, it comes into play in places where you have a very robust resource in solar. In states where you have no resources or little availability, like Hawaii, it also comes into play.

But I guess my view of distributed generation is that it's clearly an energy sale. Right? And there's a healthy policy debate going on about whether you pay them full retail rate. In my view, that's a very crude thing to do. It's not based on cost causation, but for states with a de minimus percentage of distributed generation, candidly, why should we care? It's a simple, straightforward transaction, for the time being. You could pay them avoided cost, which would probably kill the distributed generation industry, almost, or you could come up with a euphemism, like the "value of solar" project in Minnesota that somehow concluded that the value of solar was in fact in excess of the full retail rate. That's because the "value of solar" was a legislatively-defined term in Minnesota that had nothing to do with the value of solar. [LAUGHTER]

Distributed generation, in my view, probably is FERC-jurisdictional, and it's regulated by states only as a matter of tradition and convenience. It's this for a number of reasons. I mean, first, you heard in our other panel today that, clearly, distributed generation in California is having a big impact on the LMP of the California organized market. So Section 205/206, things that affect the wholesale energy market are themselves subject to FERC regulation. Notwithstanding some of the recent conclusions of the DC Circuit Court of Appeals, which we'll get to in just a second, I'm sure, but there's a lot of arguments that have gone on consequent to this. Speaker 4 will talk about one, so I needn't

get into it, but it's a very clever argument about whether, if you hook DG up to a distribution grade circuit, there is some arcane reading of the Federal Power Act in relevant case law that prevents it from being FERC jurisdictional. Maybe there is. Maybe there's not. It seems like a *reductio ad absurdum* to some degree, because at some point you're going to have to draw the line between what is transmission and what is distribution, and I can tell you, the reliability organizations across the country have found it very hard and fundamentally an arbitrary task to figure out where to draw that line. Does it matter how it's hooked up the grid? Some states require that there be two meters, one meter for the distributed generator, one meter for your retail consumption. Most states, including Montana, just have one meter that spins backwards and forwards. Does that technological difference really make any difference to whose jurisdiction it is? If you have two meters, it would seem to erode the argument that you can simply offset your purchase of energy with what is unambiguously a sale. Of course, as you heard before as well, FERC has basically either deferred arguments or disclaimed arguments, however you want to characterize it. It said, as long as your distributed generator is not producing more than you as a customer consume, we're not going to touch it. Is that a viable reading of the law? Speaker 3 will argue, no. I kind of agree with him.

The demand response bombshell. This is something that everyone was so gingerly avoiding on the last panel. We might as well take it on here. That was really an extravaganza of a legal opinion. I'm not sure if you all have had time to read what was a very short ruling. Someone at FERC summed it up to me nicely that the dog had finally caught the bus. [LAUGHTER] Thank you. That was not my line. That was someone at FERC. So you know, I agree here with Speaker 1, that as a practical matter on a grid-level, market-operator-level view, what's the difference between distributed generator or a PURPA generator, or someone

acting as the demand response? You know, a negative can be translated into a market positive. You can engage in a rich argument about the actual justification and logic behind Order 745. LMP versus LMP minus G. But the dog catching the bus thing is I think the takeaway here.

I certainly didn't expect, when a ruling finally came out on this, for the DC Circuit Court to overturn the entire jurisdictional apple cart on this. As is pretty usual, I think, with circuit courts, I would either expect some kind of limited remand for further consideration, or just sort of summarily affirmed, using Chevron Deference. But it's interesting that the DC Circuit Court has chosen to do a close reading of the law, and simply declare all demand response the province of state governments. Will that hold up? FERC has announced today that it is seeking an *en banc* review from the DC Circuit Court. We'll see where that leads.

So what are states to do if something like demand response remains in their province? How can they work together? How can they get together with wholesale markets? I'm not quite sure, but where states have become involved in generation and market design and mandating the development of certain things, you've had an enormous amount of parochialism involved, and state renewable energy standards are probably the premier example of where states have kind of come down from the clouds and said, "This is the kind of generation you're required to build," etc. And just to show how crazy things are, you can have a renewable generator in Montana that is probably unable to sell its RECs in California. A California REC would be sellable to meet Montana's RPS, but a North Dakota REC would not, except in Eastern Montana in the Eastern Interconnection, and Montana couldn't sell its RECs to North Dakota, because they don't have an RPS. There are 50 different RPS REC values and REC markets as a result of this balkanized system, and very little cooperation.

The RPS laws are a bonanza of really giveaways and special interests and legislation, and I've listed just the four impositions on a more free flow of commerce that typically exists within these laws. First, there's locational discrimination. You know, if you're going to make your electric customers probably pay more for energy, doggonit, you're going to want that project in your backyard. Right? There's size discrimination. A preference for smaller projects is often written into these laws. There's resource discrimination. When is a renewable not renewable in the context of a law? Fifty different states. Fifty different definitions. In Montana, you can burn creosote-soaked railway ties in a generator, and that's renewable. I imagine other states would not have that same impression. [LAUGHTER] And there are extraneous requirements. I'm an elected commissioner, and just later today, I have the sincere privilege of phoning in to the AFL-CIO of Montana's political action committee, which will interview me and ask me things like, do I support right to work? And other highly relevant questions to utility regulation. But surprise, surprise, you have requirements for these projects to pay prevailing wage or use locally-sourced materials, hire particular unions, even, written into some of these states' laws. At what point will these impositions on interstate commerce come to a head? At what point will they really be ripe for a court to rule on? I would suggest it's coming soon.

And again, just kind of tying things back up to what we're seeing in the greenhouse gas rules, it would of course make perfect sense if the rule stands as it is and people want to comply with carbon reductions in the least cost way possible. Of course it would make sense to have a large, wide, broadly-traded market where you specify an amount of emissions reduction in a particular area you want. And then you let a market handle it with a dollar per ton price that equilibrates around the last unit that you needed reduction to. Will that happen? I think it's very unlikely, because 50 states are going to have 50 state 111-

d plans, and the opportunities for parochialism, the opportunities for the governor to have a jobs plan--they are nearly limitless. So with that little discourse on what the Feds and the states do right and wrong, I'll turn it over to Speaker 3, unless there are any questions.

Question: When you talk about DG, and particularly on the jurisdictional issues, are you also, within DG, talking about behind the meter? Or everything? Because there is a distinction there.

Speaker 2: Yes, I am. That's the basis, I think, of FERC's disclaiming of its jurisdiction, is that, you know, so long as your production behind the meter that flows out is less than your consumption on some time-specified period, that they needn't get into it. But within that time-specified period, there are going to be hours when power is flowing out, and you're not consuming all of the power you're generating on site. And I think if you analyze it on a minute by minute, hour by hour scenario, it's clear you're conducting a sale for resale, no matter where your DG is located--behind the meter, in front of it, what have you.

Question: In your discussion of the many different RPS programs, were you arguing in favor of a broad pervasive scheme, a federal regulation of renewable programs? Or were you simply observing that as a consequence of the federal laissez-faire, we have a very inefficient existing 50 state scheme? And that's the way you prefer it?

Speaker 2: It was more of an ironic observation. I have no doubt that the federal government could conceive of something that has an equal amount of log rolling and inefficiency in it. So I would be hesitant to say it would be better. I'm just saying that the state RPSes that we have are not actually preferring the most carbon-avoiding, least-cost resources.

Speaker 3.

I want to say something about Order 745 first, since it's come up so much. First of all, I think one of the things that that court decision stands for is that if regulators make decisions that don't make economic sense, they're opening the door for really bad things to happen to them. I don't think any of the petitioners in that case really cared about the jurisdiction. They wanted to get the pricing right. I know my client did. And if FERC had come in with LMP minus G, that appeal probably never would have happened, but once you get there, and you're fighting something that is so inefficient and hurts your business--hey, bad stuff happens. And, unfortunately, we're now in a situation where FERC can't fix it.

Second point. While they're two different issues legally, I actually think the jurisdictional and substantive issues are effectively one and the same, and here's why. If a wholesaler, an LSE, is able to introduce demand response on its system and reduce its demand on the system, it saves the LMP. It reduces its energy take, and the LMP is how much money it no longer has to pay. That's what it avoids. OK? The only way FERC could get to paying LMP and the second payment that the retail customer pays was to bypass the wholesale LSE and pay the retail customer the full LMP so it got paid twice. So it was the very act of having to bypass wholesale in order to put in place the subsidy, which paid demand response effectively twice, which is what caused the jurisdictional issue to occur. So I see them as two sides of the same issue.

Also, the argument I'm going to make on jurisdiction over distributed generation I don't think has anything to do, frankly, with this one. If someone wants to disagree with me, I look forward to hearing about it, but I think they're two completely different arguments. And let me get into that.

And one more thing before I start. I'm less interested in winning the jurisdictional argument in this audience, as I am in explaining why it's important that the pricing be done right, and probably by one entity, and how net metering is distorting markets and how dangerous it is. And the reason I think it's very dangerous, Speaker 2, is that the subsidy associated with net metering is so large, that huge amounts of money are now pouring into this business, and it is growing very rapidly, and the investment bankers are telling the utility industry, "if this stays the way it is, they're going to eat you for lunch."

This is a very serious issue. It's going to grow very quickly. And the reason I know that is that very similar incentives were put in place in Germany, and it's a mess. The Germans are now in a corner with 40 cent per kilowatt hour retail electric rates, rising carbon dioxide emissions, and a very fragile and unreliable electric system.

So that happens very quickly. And let's get into why it happens. My view on jurisdiction is that if you're generating behind the meter, you are flowing power to a utility the same way any other generator is, in one direction. The only question is whether or not the wholesale part is limited to the amount that's generated in each hour in excess of the amount that's consumed on site, or whether it's the entire amount. I agree with Speaker 1 that you should meter the two separately, and the entire amount of the generation should be priced at the wholesale price, and I'll explain why, and why I think it's all FERC jurisdictional.

Let's start with an understanding of the economics. OK? So the first thing about net metering is it values every kilowatt hour that's generated behind the retail meter at the retail price. That means that if I reduce my energy take because I have a solar panel on my roof, for each kilowatt hour that I reduce my take, I don't pay, not only for the non-firm energy I produced, but, under most retail rate designs, I also avoid the transmission charge, the

distribution charge, and all the costs incurred for reliability. What does that mean? That means that under net metering, a utility is effectively providing those services, which go to the heart of what we were talking about this morning, for free. I mean, that is just economically unacceptable, and I read a lot of people who say, "Well, utilities need to change their business model and adapt to this." You can't adapt to this. You can't adapt to something which says that 70% of your costs are providing something to someone for free.

So how bad is this subsidy? Well, the average bundled residential retail rate in the United States is approximately 13 cents per kilowatt hour. I believe it was 12.6 cents last year, according to the EIA, but gas prices have come up a little. And, typically, prices in the wholesale energy market are between two and six cents a kilowatt hour. And therefore the net metered customer gets compensated, effectively, for every kilowatt hour it generates, whether it's used behind the meter or whether it goes out to the grid, at a price that's two to four times the market price of energy. But that's all it's supplying, is non-firm energy. And so the economics are so favorable here that this business is growing by leaps and bounds, despite the economic reality, which is that this is not a very efficient way to produce electricity today. This subsidy is in addition to a 30% investment tax credit.

So I've read the 10-Ks of some of the large solar panel providers, and they say very clearly that their business success or failure depends on whether or not net metering stays in place, and whether it expands. They're very honest about it. It's right there. They know it. The banks know it. Regulators need to get their arms around it, recognizing that who doesn't like distributed solar energy? I mean, we all understand that. But the economic impacts are potentially very large.

I did a chart, and I did it myself, which is why it's so basic. [LAUGHTER] But basically my

chart shows the same thing, that that solar generator is paying that homeowner, who has a solar panel, 13 cents per kilowatt hour. The central station generator, which by the way, could be a grid-scale solar generator located a couple of hundred yards away from the home, is only getting four cents per kilowatt hour, the wholesale rate. And under net metering, this homeowner is getting 13 cents for every kilowatt hour that he generates. And that is distorting investment incentives and creating some other problems, which I will talk about.

What are the implications of this? Well, first of all, there's price discrimination against those generators on the utility side. And I was on a panel with Frank Lind, who once worked for me when he was a young lawyer and I was a little bit less young lawyer. And he said to me, "The reason we're doing this is, we are very concerned in California about climate change." And I said, "Well, you're not helping to fix climate change. You're making it much more expensive to fix climate change, because you're giving all this money to these guys, when grid-scale solar and wind and hydroelectric and nuclear, none of which emit any CO₂, are much more efficient. And you're driving them out of the market and putting all the investment dollars towards this." And I said, "There's only so much money society is going to be willing to spend to fix climate change. Don't spend it badly. Spend it efficiently, or else we won't get the job done."

The second problem is that these solar generators run during the day, and many generators need the money that they get just off the system peak in the evening in order to survive. That's when your prices are higher, and you're running more expensive generation, and there are margins to be made. And what's happening is that solar is coming in at that time, and driving down wholesale prices. This is what's happening in Germany, driving down wholesale prices just off the peak, and making it harder for conventional generators to make money. And then, as we approach the evening

peak, and we need as much generation as possible, that solar is disappearing from the grid. And that's just not a great thing for our electric system.

So what's happening is, I think this is creating more missing money in the energy market. Most people in the clean energy community will tell you that the Holy Grail is matching together this distributed generation, as it gets cheaper and cheaper, with storage. But what I don't understand is, if you're paid the full retail rate just for having the distributed generation, who's going to invest in or buy storage? You're giving that away for free. So net metering is actually providing a disincentive for people to invest money and put storage in, because they're already getting paid as if they have it.

And, finally, something that was pointed out to me by one of my clients, this subsidy is not really going to homeowners. This subsidy is going to companies like Solar City, who figured out that they can provide the financing and own the solar generator, and they will lease it to the customer and give the customer a reduction in their retail rate to make it attractive to them, but most of the margin is going back to Solar City. So what we're doing is subsidizing a group of people like Elon Musk. Love him dearly. Would like to own one of his cars. But the perception is that we're helping homeowners finance and invest in these things, and that's not really what's happening.

So why is it happening? Well, first I would say that ten or 12 years ago, Mid-American Energy went into FERC, and they said, "Hey, you have jurisdiction when someone behind the meter generates energy." And Mid-American argued that FERC had jurisdiction over the whole thing. In other words, all that energy, not just the excess amount above what's being consumed on site, and FERC rejected that. FERC said, "No, look at our station service cases. We net the amount of consumption with the amount of supply over a 30 day period. And only if you are

generating more energy than you are consuming over the course of that 30 day period is there any FERC jurisdictional transaction." And of course, this is very unlikely to occur, because solar is at zero for approximately half the day. In contrast, every other energy transaction is measured on an hourly basis, and FERC is now going to 15 minutes. So they've created a different rule for this energy that applies to the energy that is transacted by a grid-connected generator. So that went along until a couple of years ago, and one of my colleagues, on behalf of Southern California Edison, went back to the DC Circuit to try to convince them to change their mind on the law on station service netting, and won two related cases, in which the Court of Appeals made it very clear that you can't use 30 day netting to establish jurisdiction. That's gone. So the basis for the holdings that occurred back in 2001 and 2009 for FERC to disclaim jurisdiction are now gone. That legal basis, that argument, is gone. And here are the decisions. You can read them if you like. One thing I will say about them is, they're as clear as mud, but I think the essential holding is very clear, and we've met with the FERC senior staff on this, and they agree. Monthly netting is gone. So that jurisdictional argument would now be very hard to sustain.

So what do I think? I think it is absolutely clear that in any hour where a behind the retail meter generator is generating kilowatt hours in excess of what's being consumed on site, the excess amount is a wholesale sale. It just is. It's a sale for resale to the utility, a sale which is getting compensated now under net metering at the retail rate. They ought to be getting the wholesale rate for energy only. The harder question is whether the amount associated with consumption behind the meter is wholesale. And this comes down to the point that I think Speaker 1 was making before, which is that you really have two things going on, and if you treat them as one transaction, you have no place to put the transmission charge and the distribution charge, and so the customer ought to be paying the full

13 cent rate for what he buys. But the other should be unbundled, and he should be paid only for the cost of the energy that he or she is supplying.

And, by the way, most of the people who are using net metering on their homes are actually using PURPA to do that. They self-qualify. If you're less than one megawatt, you don't even have to file a piece of paper with FERC. You're automatically a QF. And another thing that's happening here is that they're being paid in excess of the avoided cost rate for their energy. They're getting paid the retail rate. The avoided cost rate is supposed to be the wholesale rate. Even FERC's decision that you can separate the market into renewables and non-renewables wouldn't get you to the full retail rate. In fact, with the recent price of renewables in the grid, it's hardly a whole lot more than non-renewable energy. OK? So we're also violating PURPA by doing it this way.

And if they are not QFs, then the law under the Federal Power Act has been very clear for a number of years that the utility doesn't have to buy. There is no obligation to buy power under the Federal Power Act. As I said, the hard part is defining the quantity that's wholesale. The way FERC defines a wholesale transaction, if there is a wholesale transaction going in one direction, say it's ten megawatts, and there's a second wholesale transaction going in the other direction that's eight megawatts, FERC's view is that there are 18 megawatts of wholesale transactions taking place. There's a ten megawatt transaction by A to B, and another eight megawatt transaction from B to A. That's the law. That's the way FERC's looked at it for as long as I've been practicing. They're called "exchange transactions." And you have to report them both in your quarterly reports to FERC. You don't get to net them.

Well, I'm suggesting that that rule ought to be applied to net metering. You've got two different transactions, and you've got a

transaction for the wholesale energy that's coming out, which is displacing other energy on the electric system, and you've got a retail transaction. And if FERC were to accept that reading, then the entire amount of the output would be subject to FERC jurisdiction. Good luck, huh?

I want to go to what I think is the most difficult argument that's come back to me, and that's Section 111(d) of PURPA. You will recall that PURPA includes a number of provisions which tell states, "We want you to consider these retail rate making practices." And in 2005, net metering was added as one of those practices, and people now argue, based on this language, that Congress intended to give states jurisdiction over net metering. But I would point out to you that nothing in here says anything about the pricing, but, moreover, this isn't describing net metering as it's practiced in most of the states. This talks about electric energy being substituted for electric energy. It says it, right? It's not electric energy for bundled retail service. And so I find this definition to be completely consistent with my argument that the only thing being supplied behind that meter is energy, and that's what ought to be offset. And arguments that net metering allows you to offset for the full retail rate actually violate this provision.

So at the end of the day, I'm making a jurisdictional argument, but I'm also making another point, and that is, if we're going to go down the road that we likely are going down, we need to do on the retail side what we've already done on the wholesale side, which is unbundle the retail rate. And that's not easy. I don't claim that it's something that state regulators will enjoy doing. But if we're going to do this right and get the right economic signals out there, we have to separately price energy, the wire's function, and reliability, and we've got to make sure everybody pays for those public policy costs, you know, things like renewable portfolio standards and energy purchased above market, and requirements to put in smart meters, and any

other number of things. People who put solar panels on their roof shouldn't avoid those costs either. And that's it. That's my spiel.

Question: I think in states that have embraced retail competition, you've already seen some degree of unbundling between energy transmission and distribution. But specifically within distribution, when you say that a utility is providing certain services for free, I agree with you. Do you foresee distribution rates being split into kind of a firm and a volumetric rate, so that you actually get some payment, even for distributed generation customers?

Speaker 3: You are way beyond anything I could tell you. I mean, we are in front of this issue. And I think I'm proposing something fairly novel to say that they should be fully unbundled, whether it's a volumetric rate or otherwise, I don't know. But you know, they're going to be very interesting issues. If I've --

Moderator: Could we save that for the substantive discussion? Because I think that's more than a clarifying question. So will you be the first up when we get to the substantive section? We'll answer the question again. Other clarifying questions?

Question: What is your basis for suggesting that FERC has the authority to order retail unbundling--is it price discrimination?

Speaker 3: Oh, no, I'm not arguing that FERC has the right to order unbundling. I'm arguing that the states ought to unbundle. But this just reinforces the whole point that this wholesale/retail distinction that's in our law doesn't make any sense. It really is all the same thing. We have a bunch of sub products that are being provided. They ought to be provided in a single market, and the wholesale/retail distinction doesn't make sense. But I am not arguing that FERC has a right to order states to unbundle.

Moderator: Actually, I was going to say, Speaker 3, one thing that surprised me in your presentation is that you actually understated the amount of the subsidy, because you're not only paying them for a service--not only is the utility not charging them for maintaining the distribution system that serves them, they're actually getting paid to provide the service that in fact they can't provide and don't provide.

Speaker 3: I'm always understated, as you know.

Question: Are you suggesting that FERC must accept jurisdiction over these transactions? My recollection is, I think there's a Rhode Island case in which FERC declined to accept jurisdiction over a similar kind of transaction.

Speaker 3: I think the law is clear. FERC has jurisdiction. It's exclusive and plenary, and they have to exercise it.

Question: I don't want to put words in your mouth, but I think I heard you say that states ought not to be dealing with the "value of solar" conversation, but rather rate design. Is that a synthesis of what you're suggesting?

Speaker 3: Yes, because I think, as Minnesota's proven, this concept of "value of solar" just turns it into a political discussion rather than economics.

Speaker 4.

I am going to focus on California today, because this actually is turning into a pretty big issue in California. For those of you elsewhere, I think this will be coming to you as well. If not in the form of solar energy, it may be coming in the form of micro turbines in your basement and other things. There are other ideas floating around out there.

But at any rate, the fact of the matter is, solar technology costs have dropped radically over the last decade, and there are significant market

penetrations going on in the market. It's an intermittent technology, so therefore this has created some interesting new operational opportunities, but also challenges, for the distribution and transmission grid, which I think have been referred to earlier today. So the question really comes down to, who is responsible for addressing these operational challenges, and is the traditional split between FERC wholesale jurisdiction and state retail jurisdiction still at all relevant? And just to get to the point, no.

In California, our energy policies, if you ever want to try to figure out what they're about, they are about reducing climate change. So climate change drives everything. And solar is part of our renewable portfolio standard. My member companies bid into utility RFOs and are selected under a least cost, best fit standard, which, like pornography, we can't really tell you what that means, but, basically, solar is a competitively priced product. Recent bids are around six cents a kilowatt hour. They may be going lower. They're interconnected to a grid level transmission system, and under a Cal ISO tariff, and the contracts for these resources have curtailment provisions and other operating provisions, and they are presumed to be wholesale.

Now, on distributed generation, you can be a distributed generator in California and be up to 20 megawatts. And to put that in perspective, that's about 100,000 solar panels. So this is not just what you can do on your own roof. This can be larger. There are a number of programs in California that are driving distributed generation. The one we've talked about here today is net metering, and, as you heard earlier, it is a bundled retail rate, and it's based on the tier you're in and time of use. There is a separate payment, more akin, actually, to a wholesale energy payment, for any surplus energy that you've netted out, and my guess is that it basically can be up to four times what you would be being paid at a wholesale level. It's

about 35 cents in Edison. In PG&E, I think it's 41 cents, or something like that. So, basically, if you're an upper tier customer, and you're not putting solar on your roof, you're an idiot. And so this has more to do with rate making in California than with the technology, but that's kind of where we're at.

So, obviously, these distributed generation resources are interconnected at a distribution level. One of the important operational issues here is the ISO sees DG, basically, as behind the meter, and as load, not generation. So if a marine layer moves into Southern California, they don't see generation dropping. What they see is, all of a sudden, 500 megawatts of new load showing up. So that can be an operational challenge there. And of course, here it's presumed to be a retail transaction.

And to Speaker 3's point, leasing has now become the primary vehicle in terms of the market here. I think last year about 70% of the market in California was leasing. My brother has one of these lease deals. He saves 10%, and as Speaker 3 says, the people who put the panel up there obviously get the ITC (investment tax credit) and the other issues associated with that. Obviously, solar is a great resource in the middle of the day. It is obviously weather sensitive, and while the sun never set on the English Empire, it does set over California. So at night time, we have challenges. The legislature may change that, but right now that's the case. [LAUGHTER]

So there are operational challenges here, and these are not insurmountable, but they're real. The California ISO observes ramping needs, and these are seasonal. This is going to be the only discussion you're going to hear from a Californian this year that's not going to make you look at a duck chart. [LAUGHTER] All right? You appreciate that, I hope, because those of you who've been to all these meetings, you always get to see the duck chart. No duck chart here, but at certain times of the year you can

have an afternoon ramp, as the sun goes down, basically, so with solar panels not only on the rooftop, but wholesale as well, the necessary ramp could get up to 13,000 megawatts by 2020. So this is not an insignificant issue, and we're trying to deal with that.

As I said earlier, the local rooftop stuff is not metered to the ISO and is not dispatchable or curtailable, so we've got issues there. And we already talked about the pricing issues with respect to the gas fleet. There is no current mechanism to keep the gas fleet around to basically integrate these resources. So we're kind of working on that, but I don't know, I can't tell you what the answer is. We don't want a capacity market, God forbid, so I don't know what in the world we're going to do, but this is a live issue.

And then it's clear that over generation on distribution circuits does in fact affect the transmission grid. If you go to the California ISO website, there's a really cool toolbar that says, "Renewables". And so if you go to that, you can see in real time what's going on in California. So this is a picture we took, oh, about an hour ago. You can see no solar out in the early morning, and then how it ramps up. Probably by now it's up to about 4,500 megawatts of utility-scale metered solar. There's another 2,000 megawatts of rooftop that's pretty much following that same line. So it's a significant amount of energy in California. That is the equivalent of what our nuclear fleet used to put out.

So the paper Speaker 3 wrote is raising the question, is Net Energy Metering (NEM) a sale for resale under the Federal Power Act? The question is, does PURPA limit NEM pricing to avoided cost, not the full bundled rate? And a question which is kind of a counterargument--how is the non-use of customers under NEM any different than energy efficiency? I mean, no one's talking about charging people for putting in LED light bulbs. There is no sale under NEM,

other than people are just netting out electrical services.

And then there is this theory that there is no federal jurisdiction because the transactions only occur on a distribution system, and there's no interstate transaction at all. It's all intrastate. So I won't go over the view that NEM is inconsistent with federal law, since Speaker 3 did such a brilliant job explaining that argument. We don't need to deal with that slide. But there is this other theory that I want to touch on. Speaker 3 talked about Frank Lind, and Frank used to be the general counsel for the California Public Utilities Commission and wrote a paper with respect to how intrastate wholesale distribution facilities are not in the federal jurisdiction, and I have a cite at the back of my slideshow for that. So, as I said, he used to be the general counsel for the PUC. This should tell you where my commission's going.

So this is going to get very interesting. And as a member of both California Energy Bar and Federal Energy Bar, great things are about to happen. The states retain jurisdiction of the distribution facilities under the Federal Power Act, so, in other words, hands off, FERC. States' organic police power allows them to basically come up with the rates, terms, additions, interconnection requirements on the distribution system, and this extends to feed-in tariffs, development of microgrids, and anything else out there. The theory here is that sales on the distribution system don't migrate into the transmission system. So if I have a solar panel on my roof, it's basically meeting my load, and maybe if I've produced too much, it goes to my neighbors, but it really doesn't ever leave the distribution system. So therefore there's not an interstate sale. And so, therefore, since federal jurisdiction is limited to interstate commerce, any sort of federal regulation of this really doesn't apply.

There are a number of papers beginning to float around California where people are having

stakeholder meetings where we're talking about these things. And it's clear that there is a strong interest in people trying to rethink what the model ought to look like, so that utilities are going to go away. That's the theory. And they're going to be replaced with something different. There's demand energy resources ("DER"), which includes not only distributed generation, but storage and electric vehicles as well. And the idea here is basically that there is going to be generation at a retail level, and that is going to sort of migrate into providing ancillary services in the Cal ISO market, and whatever. So people are already talking about crossing whatever mysterious line we have there now. We're well on our way down that path.

On the 745 Order, the Court of Appeals that vacated the Order says, "Demand response is not a wholesale sale of electricity; in fact, it is not a sale at all." And so then this gets back down to the question, what are the implications, if there are any, for now? If you buy the theory that all you're doing is basically not consuming electricity from the utility, is there a question here? I'm asking it as a question, but I don't have a strong opinion on it. But I thought that since it was fresh in everybody's mind, we ought to stick it in here and figure out if it's relevant.

A lot of people ask, "Why in the world would the federal government want to regulate my roof?" OK? I mean, how dare they? When you're in law school, there's always this case that you scratch your head on. So there's an old case called *Wickard v. Filburn* that goes back to the regulation of wheat. It was the middle of the Depression. The federal government had a program where they basically paid you a fixed amount for wheat, and basically Farmer Filburn grew his own wheat for his own use. This was an early farm-to-fork. It was going to stay on his property. He was not trading with his neighbors or anybody else. And he claimed there was no interstate commerce. The Supremes said, "Not so fast. Because by home growing your own wheat, you're not participating in the market,

and that's having an effect. If everybody did that, that would affect the wholesale, that would affect the wheat market. The federal government has regulated the wheat market. Therefore, you violated the law."

So, NEM customers are self-generating. Is that affecting pricing in the wholesale market? Again, is it more akin to some sort of non-sale limited use of electricity? So if the federal government can regulate wheat, why can't they regulate electrons? Now obviously under the Federal Power Act, there are some limitations on what they're supposed to be doing. But the only purpose of this slide is to sort of bracket this from the standpoint of showing that it could go pretty far down, I think.

Last but not least, what are my theories on this? New technologies, new products, and new participants have blurred these distinctions between wholesale and retail. This is accelerating. It's not going away. There is a huge amount of money associated with this. So we're going to see more of this. We shouldn't panic. We've been down this road before. The Federal Power Act has been subject to evolutionary change for a long time. There'll be plenty for FERC to do, for NARUC to do. There's plenty of resolutions here coming up with where these jurisdiction boundaries stand. The Federal Power Act will need to be updated. The sun is expanding, and will destroy the planet in a billion years, so there's plenty of time for Congress to act. [LAUGHTER]

General discussion.

Question 1: Speaker 3 talked about distribution services being provided for free such that a behind the meter generation unit is avoiding certain fees. Do you see the states taking on a bifurcated distribution rate? So that the distribution rate itself would be split into a large fixed component that everybody who breathes pays, and then on top of that, a volumetric component so that the customers without

distributed generation pay that as it flows, and that could be a way for the distribution utilities recovering money for services offered?

Speaker 3: I think there was a case in Arizona that this got started with APS proposing a two part rate that had a capacity fixed charge that everyone would pay, regardless of usage, not applied just to distribution, but to the entire retail rate. And of course, the response was unbelievable about APS wanting to kill solar, and it was very, very hard hitting, nasty stuff. And I think that's what the states face on this issue. And it's a really hard political issue. Standing in the way of letting me put a solar panel on my house is a real tough one to respond to. And so the answer is, yes, that's one of the things they could consider doing. It's already been proposed. But, boy, as it turned out, it's really hard to get this right politically.

Speaker 2: Obviously, you'd need to do a cost of service study to figure out exactly what is avoidable on the distribution system that a DG customer, a net metering customer brings to the grid in order to justify two different rates. My assumption is that most of those fixed costs probably are unavoidable, but that there may be some distribution costs and improvements out into the future that might be mitigated or avoided as net metering customers come onto the grid.

Speaker 3: So it would have to be cost based, and I would just say, in terms of whether or not this is a big issue, fundamentally it's all a simple division problem that's at the heart of cost of service rate making, which is still the method of creating distribution and transmission rates, where the numerator is some amount of unavoidable fixed costs and the denominator is either throughput in megawatt hours, or number of customers, if you're straight fixed variable, and the quotient is a rate. And if you have only 1, 2, or 3% net metering in your state, that doesn't rise to a level to undermine the

durability of that basic division problem. If you're California, maybe it does.

The way we deal with the problem is, we don't charge any resources to access the grid, and because what we call net metering is measuring the inflow and outflow separately, you continue to pay your full share. Now, if this were a topic about energy efficiency, which also affects both wholesale and retail markets, then there's a question.

Speaker 4: I'll just point out, I live in the Sacramento Municipal Utility District, which has an elected board, and is a very progressive utility that buys lots of solar and geothermal and whatever, and that's exactly what they did. They put a demand charge in that's gradually growing over the next five years, and they adjusted their time of use rates. The idea there being, the general manager basically says, "If my customers, who own me, want to put solar on their roof, I will help them do that, but we don't want to do any cost shift to other customers for those fixed investments we've already made." So you might want to look to what they've done there.

Question 2: Speaker 3, I was once doing a transaction with a wind developer who had a QF contract with a utility in Idaho. And I wanted to buy the renewable energy credits. The California RPS, which Speaker 2 alluded to, had lots of quirky rules. One of them was that RECs could never change hands in an unbundled fashion. So they always had to be bundled with energy. So I proposed a structure. I would buy the energy and the RECs. I would instantly sell back the energy, hold onto the RECs, and do what was called a firming and shaping bucket two transaction. The concern came up, then, with my wind developer, that somehow their QF contract would be at risk, because the utility could say that this power is now comingled with the power in the grid, and QF contracts, you know, are specific to facilities. So I helped write a petition for a declaratory order with Idaho wind, and the

argument I made there was that the transaction happens inside the fence of the facility, so the power never enters the grid to be contaminated. FERC basically punted. They never said anything. But when I thought about it, I thought they could have said that since it never enters the grid, it's not in their jurisdiction, and that's also the view, too, from Frank Lind. So I was wondering, what's the rebuttal? Is that correct? Am I wrong?

Speaker 3: On Frank's argument, and this concern, I think the law is now fairly clear that the entire grid is one machine. The electrons all comeingle. They get excited. They're like teenagers. They all get excited and comeingle. [LAUGHTER]

So I don't think the argument is consistent with current law. However, if I were looking at the Federal Power Act for the first time, and reading the language in the Federal Power Act about the distinction between transmission and distribution, I could reach a different conclusion about that, and I think that's kind of what Frank in part was saying. And he admitted to me that he thinks he's trying to move the law in a different direction from where it's been now. I don't think that's very likely, but it's possible.

Another point I want to make about that is that with respect to this distinction between transmission and distribution, one of the key factors that FERC uses to determine whether something is transmission or distribution is whether the power is going only in one direction. On the distribution system, it's just all going out to the load. Once you start using the distribution system to move energy that's generated locally, now you've turned the distribution system into a low voltage transmission system, effectively, and so it's not beyond the pale that FERC would assert jurisdiction over those facilities anyway. And FERC has been very creative in finding ways of reaching into the distribution system anyway.

And this also gets to the point that Speaker 2 raised. I think the argument isn't really whether someone who has got a solar panel on their roof and still no storage is using the distribution system to an equivalent manner to someone who buys all their energy from the grid. If you put a lot of this in, you've got to invest a lot of money in the distribution system to make it work. Don't you? I mean, I think that's an issue you guys are facing. So the argument is, are they responsible for more than their otherwise equal share of the distribution system, not less?

Question 3: You know, around the country these issues have come up nearly in every state, and I think the conversations are really constructive and ripe, and they're not easy conversations, but we are recognizing now that customers actually like distributed generation. They like to own it. And they own it or lease it...and I would quibble with whether or not the customer benefits owning a lease system. I do. I have a lease system, and it financially makes a lot of sense for me. So however that transaction works with a company like Solar City or a leasing provider, as long as it benefits the customer, if they keep the tax credit, that's OK with me, because I'm getting other benefits from that leasing arrangement.

Nevertheless, there are conversations on this issue taking place in every state. The focus seems to be on solar. But I would argue that it isn't just about solar anymore. It is really about the future of the grid and all the different interactions that are taking place, and one and the same with the conversations going on with wholesale versus retail.

Two states right now up here in the Northeast are looking at this issue in a broad level. In Massachusetts today, they issued an order in their grid modernization docket calling upon the utilities in Massachusetts to file long term plans for how they're going to modernize their grid, how they're going make investments in the grid to accommodate, not just DG, but electricity

storage, energy storage, electric vehicles, demand response, all those different things. Part of those plans will include fair and adequate rate recovery for the grid upgrades that are going to take place, and for other things that take place on the grid. Maybe it's the DG customer that pays for part of what they're doing. Maybe it's the electric vehicle customer. Maybe it's the utility, in instances where the grid is benefiting, and not just the individual customer. So there are a variety of ways to think about it. That conversation isn't over yet. It's really just beginning, but Massachusetts is trying to take a progressive look and think about the future.

The same thing is happening in New York, and it's called the REV (Reforming the Energy Vision) docket. The commission issued an order on April 24th. It's broad-based. It's complicated. But it's addressing some of these issues. So, to the panel, can you comment maybe a little bit on the wholesale/retail relationship and grid modernization and what some of the commissions are doing in thinking about, not just solar, because it isn't just a solar question, but some of the other technologies and behaviors that are really changing the grid?

Speaker 3: I think you've made a good argument that there are political justifications for what is admittedly a cross subsidy. And it's not just distributed --

Question: Oh, I did not say that. And I know you're saying that intentionally. But that's not what I said.

Speaker 3: Alright. But I was actually going to rush to a feeble defense of distributed generation. Distributed generation is just one recipient of cross subsidies in a system that is built on socialized costs. And I live in a rural area served by an investor-owned utility. There are maybe four people on a radial distribution line of a distance of two miles. I am very grateful for my fellow rate payers for tolerating the extreme expense that I impose onto the

system, while still continuing to pay the retail rate that everyone else does who are customers of that investor-owned utility. So that's just one example of the cross subsidy. Not to be too snarky, but there's the famous H.L. Menken quote that the theory of democracy is that the people know what they want and deserve to get it good and hard. [LAUGHTER] And there's no question that distributed generation enjoys a huge amount of political support when it's polled as an issue. And then it enjoys less support, but still a surprising amount, when the poll question is asked, "Do you support it, even if it costs more, even if there's a cross subsidy?" And people raised their hand and said, "Yes, we'll pay more."

Speaker 1: One question that I raised earlier, and we haven't had to deal with it in Texas yet, is whether we should treat DG differently with respect to recovery, than we treat normal generation, which, again, doesn't pay anything to maintain the grid. Load pays. But is there justification for that? Or should we say that, no, if we did that, that would be unduly discriminatory, because open access to the grid by everybody is baked into our law.

Speaker 4: That was actually one of the points I was trying to make that you brought up earlier, which is basically that the people are now taking a hard look at the distribution system in California. First of all, in many places, it's pretty old. OK? So it needs to be upgraded anyway, and it's not only because of it the DG issue, but 40% of our greenhouse gas is associated with transportation. So there's a major push to try to electrify the fleet, so if everybody buys a Volt like I did and starts plugging it in, you have a very similar problem for the distribution system. So it's being asked to do a lot of different things. And the purpose of this panel is to try to lay those issues out and try to figure out what's the most equitable way of actually dealing with them.

Speaker 3: So other than the fact that we're both Volt owners, who's going to pay for all these upgrades? A substantial amount of money needs to be invested in our grid in order to accommodate all of the new technology that's coming along. With net metering, you've got people coming along, and they're not going to pay for any of it. And as that grows, there's a smaller and smaller customer base, and so your costs have to get spread among fewer customers. Their rates continue to go up. And in the end, it doesn't work. And that's why this particular subsidy, to me, is very dangerous. And I don't know about you, but I'm reading all this stuff about the "end of the utility industry." People think they can put a solar panel on their house, and they'll pay very little for electric service. And the economics don't add up. And that's the problem that Germany has right now. The subsidies are so big, and, of course, they're trying to exclude their high energy industry from paying any of them, so that they don't become uncompetitive, so everyone else's rates are going through the roof. It just doesn't add up unless everyone's contributing a fair share. And, yes, there are subsidies throughout the energy industry, but, boy, this one of getting paid two to four times the market price for your energy, that's a big one.

Questioner: Can I just respond quickly? I think that the conversation has actually in many places moved beyond that. I would draw your attention to the conversation that took place in Arizona, which isn't over yet, I don't think, and people are trying to assess what is the true value and the true cos. I think the initial reaction that you saw in a place like Arizona and some of the other states maybe a year ago or two years ago, was that the discussion was all about costs and nothing about the benefits. And I think a lot of people would argue, and I would argue, that there are benefits to distributed generation that have to be calculated and thought about as you go through this process. One of the things that Minnesota did was do that, and maybe they

didn't get it right yet, but at least they started to think about what the benefits are.

The second thing is, I think there are solutions happening in Germany, and Germany's mission was probably like California. It was about greenhouse gas. It wasn't about necessarily getting a lot of solar. They have other objectives in mind. And I think one of the things that they're working on now, and people are thinking about here, and even in California, with the E3 report, is recognizing that there are solutions to some of these challenges.

And the third thing I would say is, these challenges exist whether we do distributed generation or not. Our grid has serious problems. That's the motivation in New York State for its grid modernization docket. It isn't because, necessarily, they want more DG. It's because their grid has issues regardless of what's happening with technology.

Speaker 3: You're perhaps misunderstanding me. I'm not against distributed generation. I'm someone who thinks it's part of the American spirit that someone wants to put something on their house and produce energy for themselves, that that's a good thing. What I am worried about is that we are, through this net metering, creating such a large subsidy that we're undermining the entire scheme here as we go. And I am animated by Germany, because I think that's exactly what they did, and, boy, are they in a mess. So don't misunderstand me, please. I am not here saying we need to continue to have the grid we've had for the last 100 years. I'm someone who believes in technology. I would like us to move forward. But some of the things I'm seeing, and particularly the reaction when the utilities raise their hand and say, "Hey, maybe net metering's not a good idea"--the political reaction was just so violent that it's really what caused me to write this article. OK?

Questioner: Just one more quick thing. I think that there's something between that and the \$50

a month fixed fees that some utilities have proposed. And what a lot of people are saying, including myself is, do the analysis before you make up a \$50 number that may not be fair.

Speaker 3: Why don't we just unbundle the retail rate and let the market go?

Question 4: I wanted to go back to some of the comments that have been suggested by Speaker 2. I am a big fan, and I agree with you on your 50 states versions of RECs. It's a challenge for all of us, and we're having that conversation in Arizona as well.

Speaker 2: There's a however coming.

Questioner: There is a however coming. And that goes to the exchange you just heard. It concerns me a little bit that there are states, perhaps, that are ignoring the net metering conversation. And, I guess, having lived through the experience in Arizona, I think our chairman would probably concur, having the conversation sooner rather than later, when you do have a *de minimus* amount of DG distribution, probably makes sense, versus having to go through it, and the cacophony of 30 second cable TV ads on both sides of the issue, which doesn't lead to good decision making, although I agree with our decision in Arizona. I think we waded our way through that. But I think that's not a good mechanism to do what has to be a much more completed conversation, which we are doing in Arizona. I think both sides of the issue would suggest that. So I just ask the panel whether you think I am being overly cautionary in suggesting that we ought to have these conversations in states that don't have a huge penetration of DG yet, be they about solar or other mechanisms. I personally think it needs to be now, not five years from now. But I could be wrong, and that's my question.

Speaker 3: So in my article, I made the following argument. And that is, if you don't do this now, once a lot of people have put in solar

rooftop generation, relying on the economics of net metering, and then you take it away from them, that's going to be politically very hard to do. In addition, if you wait, and then you decide just to take net metering away from new people, the people who haven't gotten the advantage of that economic subsidy are going to yell and scream, "Why I can't do it when my neighbor can?" So that's my long way of saying that I agree with you, and it's very important that we get on top of this sooner rather than later.

Speaker 2: I think that is a fair point, and, you know, I'll just leave it there. I will just reiterate, though, in looking state to state to state--I mean, there are dozens of states that have less than 1% of distributed generation, and, you're right, if we moved on it, we would only have 50 public commenters, rather than 500 or 5,000, as you probably did. So, yeah, point taken.

Questioner: And you're absolutely right, it's a very small number for those small states. But your math is probably right on that for DG. It's more like 50,000 emails, and it's a lot. So now may be the time.

Question 5: I guess the basic question is, what's the difference between DG and DR as we've been talking about it here, other than that DG, as we're talking about it here, is relatively useless as an operational tool to the system operator? I'm not saying it's a bad thing. I'm just saying it's not dispatchable. It's not a tool that system operators can use. But as we're talking about net metering, where an onsite generator is used as an offset, but only a partial one, so there's no export going on, how is that anything different than a customer not turning on his lights? Like energy not consumed, other than that there's a cost associated with running the generator, or maybe not if it was something with zero cost?

And the other question would be, probably about 20% of the DR that's out there that participates in these markets, and probably a larger percentage in the economic markets that are

relative to 745, actually comes from behind the meter generation. And how is that generation, other than that it doesn't run 24/7 and it's also typically larger, how is that any different than the behind the meter generation that we're talking about here? And if FERC doesn't have authority under Order 745, the EPSA decision, how can have authority simply because the sources are smaller and they run all the time? So what's the difference?

Speaker 3: Your point's a good one. I think the best answer I can give you is that maybe it gets to how demand response should be treated when we unbundle rates. What is being avoided? If the customer's going to be there on peak, then you have to build as much transmission and distribution to serve them as you would otherwise. And I think ultimately what you're really saying is, "Man, this is really complicated to get done right." The distinctions are very small. So I actually think your point is well taken. But I stand by the economics of my argument as well.

Questioner: And I'll just ask for Speaker 4 to follow up. So if DG is equal to net energy, or net metering, does that mean it's also equal to demand response? Or do you see a distinction between the two?

Speaker 4: I hadn't thought about it with respect to demand response. So how's that for a nice, short, sweet answer? The reason I even put the 745 decision in there is because that's a legitimate question—if, in fact, all we're doing here is netting out usage, is it really having an impact on the system? And I think his point is basically that it's a question of how you're pricing stuff. And I think that's correct. Which then leads to, OK, so what are we going to do about that? Do states still have jurisdiction over that? Are we back to a PURPA mode, where we're basically determining avoided costs and what goes into that? I don't know. If there are parallels to demand response, then maybe.

Speaker 1: Actually, I would argue, at least in Texas, that there really isn't a distinction between DR and DG. We already have a number of retail customers who have installed gas generation, and originally large commercial or medium sized commercial entities, for example, they did it really to manage their distribution interruption from storms and equipment failure, but they also use it now to bid in into the ERS (Emergency Response Service) program. In the example I gave in the presentation, the person is using DG and is aggregating it and is bidding it into what originally was a DR product, an ERS program. So it's DG generation that's providing DR. And in that context, it's one in the same.

Speaker 2: The only response as to why should they be different is arguably that the law says so. I mean, it certainly doesn't make any sense from a market perspective, but you have an opinion of the DC Circuit Court that takes a very close and strict reading of the law, written by a judge who is famous in Cato circles for just such readings of the law. And she says, "A buyer is a buyer, and a reduction in your consumption is not a sale of electricity at wholesale." That seems pretty obvious—a close reading of the law, but it speaks to the fact, and there are other legal arguments that will be countenanced, I'm sure, at the en banc review, such as that demand response obviously does affect the wholesale electricity market, which perhaps does give FERC authority. But perhaps it's a testament, if that reading of the law holds, that the Federal Power Act is not a nimble creation [LAUGHTER] to deal with the realities of a grid of 2014. Exactly.

Speaker 3: By the way, people don't know this, but the "affect and relate to" clause, if you read the language of the statute, it's practices of utilities that affect or relate to the wholesale market. That's what the statute's talking about, and FERC found that demand response providers are not public utilities, and the dissent failed to deal with that argument. I just would point that out.

Question 6: This isn't a question. It's sort of a clarifying comment for interest. I was at a conference just last week, which had many interesting presentations, but one of them that's most interesting and relevant to this discussion here was done by Severin Bornstein from Berkeley, in California, if you know him, a very competent and knowledgeable person. And he and one of his colleagues had assembled essentially every solar rooftop transaction--data which is publicly available, but they put it all together. So they had each individual purchase by customer, and they tracked what they were using before and after and all this kind of stuff, and they could break it down by approximate income classes, and they knew what their rate structure was and where they were on the net metering, and all this kind of stuff. And it only goes up to, like, two years ago, I think, because of the data lag of getting all this information.

But let me just summarize the three principle things I remember that are relevant to the conversation here. First is that they zeroed right in on this lease versus buy question, because if you buy under different rules, you don't get the 30% investment tax credit, but if you lease, the person who's leasing it to you gets the 30% investment tax credit. So that had a big impact on people switching to leasing rather than buying. Second is that it was clearly related to this tiered rate structure, so most of it was going for the highest tier, and then the rooftop installation was sized to get them right up to the edge of the tier, so they dropped down to the next one. So it was clearly being driven by that net metering incentive. And then the third thing, which is a little bit harder for me to fully understand, but it may have to do with this leasing and who's getting the benefits, from the point of view of the customers, as opposed to the people who are leasing to them, the net present value that they calculated of all of these different things was in some years negative and some years zero, based on the calculation. So it wasn't like the customers were capturing big benefits here. It wasn't a big profitable thing from their

point of view. Now, there were profits to be made by the installers, which is a different thing, but they don't have data for that, so they couldn't look at the underlying cost structure. I'll try to get this paper posted on our webpage, if they'll agree to that. But we'll get the information. But you should look for this, because it's a very, very extensive database about the actual experience in California looking at it, and the analysis is very careful.

Speaker 3: You are suggesting that rate payers are not *homo economicus*, that they're not the rational man. [LAUGHTER] You know, I'm very curious on the third point, and maybe it feeds back into what our earlier questioner has been saying--people just like the idea and are willing to pay more for this sentimental notion that they're doing it themselves.

Questioner: The technical term that Severin used was the "feel good premium."

Comment: The only feedback I would give is if the data's two years old, the prices have come down significantly, and so the economics are different now, and I think dramatically different even than two years ago.

Speaker 3: And I would say, I think people should be able to do what they want to do, even if it's not economic. If there's a feel good premium, that's what we're all about here in this country. But in this case, they're shifting the cost to their neighbors, and that I have less sympathy for.

Question 7: I want to start with a couple of observations and basically get the panel's reaction to them. Speaker 1, you laid out the beginnings of what I think is perhaps the next real fundamental change in electricity markets when you talked about the communicating thermostats, the Nest thermostats and what their capabilities are. In Texas I know there are some examples of as much as a 50% reduction in air conditioning use during peak periods because of

precooling of homes with these smart thermostats. One can easily imagine a situation in which this becomes more ubiquitous, and it doesn't just occur in response to specific events, but it occurs 365 days a year in every interval from interval to interval with devices deciding when they're going to use electricity and when they're not, based upon anticipated price impacts over the next several hours. That clearly would change the load shapes quite dramatically.

In Texas you have actually the ERCOT forecast there indicative of interval prices going forward. That's not true in every RTO, but it is true in a couple of them. But the key thing that I think has kept this from happening is that we still have demand settled in the RTOs on an hourly basis, and, typically, in most RTOs, the distribution utility settles with the LSEs based on representative load shapes, not necessarily on actual load shapes. But one could easily imagine that changing, and I'm curious about what the panel thinks about whether that happens. Is that necessarily something that FERC has to do, or can states take on making those kind of settlement changes happen, such that the LSEs serving those customers could, for example, offer a penny reduction if they had the ability to see a thermostat that would modify usage by a couple of degrees in order to get the savings. So that's one thing I'd like the panel to respond to.

The second thing that one of the earlier questioners mentioned is the New York proceeding, where we have a New York commission that has said, "We want to have distribution level markets in order to facilitate both demand responding and participating in the markets, and distributed generation," and is that something that a state can do? Or is that necessarily federal jurisdictional, and what are the issues that will arise?

Speaker 1: In terms of your first question, the other piece of that is not just the thermostat. That's one. Although I'm not sure even that's required. But you also have to, I think, to tie it to

a retail product that it sends it through. There are actually free nights or weekends with more than one retailer now, so if you had the free nights, then that really would drive the behavior, because you would be cranking down to 60, and then turn your AC off. The other is, just a --

Questioner: I guess my point was that you don't have to change the behavior if the retail supplier can have an agreement with the customer that says, you'll have a Nest thermostat, and the Nest thermostat will have two degrees of temperature flexibility from your set point. And we'll give you information that will help the thermostat decide when to adjust. You could just have a flat price that was at a discount, and the thermostat would automatically do this, and the customer probably wouldn't even realize it was going on, because the changes would be smaller.

Speaker 1: Those products are on the market now. I know at least one REP that does that.

Questioner: So I guess my question is, where do you see the barriers to that getting more broad application? And clearly it's something that you can track, because it's not being dispatched, but --

Speaker 3: Well, it sounds like a technological problem to me. It just sounds very hard to do. I mean, it obviously sounds right, but I don't know enough about the technology. To create a separate load shape for each customer and let them work off that sounds like hard work.

Questioner: Actually, I think Nest and other people are doing it. I know at least two companies that are doing it today.

Speaker 3: But asking the LSE to then take that into account, how it prices to each of its five million customers sounds...the question is whether it's worth the amount of money they'll have to spend and the effort to get it done, and I couldn't begin to answer that.

Speaker 2: If Speaker 3 is right about distributed generation, it means they're all PURPA projects, which means that establishment of avoided costs falls right back into states' laps. The difference is whether or not it emanates from the organic police powers of the state, or whether states simply have to set avoided cost using whatever creative methodology they would like in compliance with FERC regulations. But obviously FERC hasn't come down and said that you can't quantify, say, the capacity value of small distributed generators in terms of their potential contribution to distribution circuits. I mean, that could be a creative argument that would allow New York to do basically exactly what it's doing, even though it would be a color of enforcement of federal law, or enactment of federal law.

Speaker 3: But then, of course, if you try to distinguish between firm service and not firm service, the DG provider would see.

Question 8: So I had been thinking that fixing net metering to appropriately integrate distributed generation was really going to be a state by state negotiation. But, Speaker 3, you had suggested that actually FERC had jurisdiction over this, and they just needed to exercise it, and I think in terms of unbundling retail rate and maybe taking over not only the transmission piece, but the energy piece, I wondered if I had understood that right, if that was a serious suggestion. And what would that look like if they were to exercise such jurisdiction? Is that a rule making? Is that lawsuits against the states? What, practically, does that look like?

Speaker 3: Well, first of all, it was serious. I don't believe that FERC has the right to tell states to unbundle the retail rates. I didn't intend to say that. I did intend to say that that would be the right way to fix the problem economically, if you could design the rate correctly. But on FERC having jurisdiction over net metering, I think there are very serious conversations going

on right now in Washington about whether that issue ought to be brought to FERC, and so we'll see where it goes.

Speaker 4: Wouldn't an argument be that if these are in fact, PURPA, then the states already have the ability to determine avoided costs? And then the question is, is net metering avoided cost or not? And you'll at least 50 different answers.

Speaker 3: So the argument would be, one, that FERC has to assert jurisdiction, and it can't enforce discriminatory pricing in which some generators get the wholesale rate and some get the retail rate. The second argument is that PURPA is being violated, because distributed generators are all QFs, and they're getting paid for their energy in excess of avoided cost. Those are the two primary arguments that would be made.

Question 9: It's been discussed, as everybody knows, for I don't know, a year or two years, that there needs to be another way of doing this, and New Jersey has a lot of solar. We've been working it for like 11 years now. Arizona, Hawaii, California all have some areas of issues, but it's still a small part of the electricity generation. I think New Jersey we are not quite at 2%. In New Jersey some of us have always known that net metering will eventually have to go away, because it's totally unfair. The only reason we did it was because it encouraged the growth of the industry. And so that has been my position for ten years now, easily, that net metering has to go away. But if you do it in states that don't have much solar, you're not going to encourage the industry to grow there. Add that to the good feeling part of it. Also add to it, since extreme weather has happened with Sandy at all, that terrorism, whether it's cyber terrorism or physical terrorism, is a fact. We know that China and other have gotten into a lot of computer systems, and that companies know this, because the Times and others wrote about it. And they know about Sandy. They know

Princeton and other places stayed up in one microgrid.

Distributed energy is the future of the country, because customers are walking, because for them, for practical, commercial purposes, they need that electricity. They also need the grid for the backup, certainly for the long term, for anybody who's talking about it in the business community. So that's why we're talking about a new way of doing business, because it's going to be happening.

So I guess the two issues are, Speaker 4 mentioned time of use rates. I've thought about maybe some kind of pilots of dynamic pricing for solar customers, to see if in a state like New Jersey, where for our electricity costs a big problem is the peaking, whether that would take care of it, because that's when they're going to be using their own electricity, and if they're not home, they can be selling it back in at a really high rate. Are any states thinking about doing that? Is California working on that, when you talk about the time of use rates? I can't follow California. They're changing things all the time. So that's the first thing. What are the different ways of doing this for the states that have a lot of solar, or that are building a lot of solar?

But also, I just wanted to mention, with respect to Germany, Germany did feed-in tariffs, for God's sake, and Spain too, and that's what killed them. We never did that. The industry wanted it. It was just a bad thing to do. I don't think it was net metering that killed them off. I think it was the feed-in tariffs.

Speaker 3: But their feed-in tariffs were set close to the retail rate. I mean, economically, it was very similar. Now they're below it, and the solar industry is screaming. But why don't you just unbundle your retail rates, let people compete to supply the component services on a level playing field, and let the market develop?

Questioner: That might make sense in a state where you have a solar industry. There are very few states that have that. It's not going to develop in the other states.

Speaker 1: There is actually another alternative. My own experience in this is that probably four years ago I was assigned by my colleagues to look at whether to do a rule making to have a specific carve-out under our RPS for non-wind. And the real proponents were solar. And during the course of that, they kept saying to me as one of their arguments, "Oh, but the price of solar is coming down to fast, you know, this thing can go away, and just do it for four or five or six years." And at the end of the day, we didn't do anything. Because (I can't speak for the others in terms of what they were thinking) but I kept thinking, "Wait a minute, if it's coming down so fast, why do I want to be an early adopter?" Now, fast forward 4 ½ years later. Recently one of our large munis signed a 200 megawatt deal for five cents a kilowatt. We also, this spring, have plans for a pure merchant IPP, 22 megawatt plant in far West Texas, so it's almost in the mountain zone, with no subsidy. They're just accessing the market. And so if you let the market actually react and not interfere, you may get what you want without bureaucrats like myself actually sitting down and saying, "Oh, we want to do this, we want to do that." The market actually says, now, that it's cost effective. The lines have crossed. The costs of the investment have come down to the point where wholesale prices will deal with it.

Questioner: I just think there's a big difference between the Southwest, Arizona and Texas, and states like New Jersey, Maryland, and Massachusetts.

Moderator: Actually, let me respond to that from the standpoint of actually dealing with this, at least in a tiny part of Massachusetts. One is, if you start with net metering, you're going to get the least efficient possible renewable generation. You're going to get, just call it sort of naked

solar panels. No storage, nothing. Far less efficient than large scale renewables. So what you're subsidizing is the least efficient possible source. And why would you want to do that and maintain that over a long period of time?

Questioner: Because in a state, at least like New Jersey, and I would guess in Massachusetts, Connecticut, and Maryland, first of all, we don't have a lot of land for large solar. Secondly, we don't have the sun like they have in the Southwest. And so in New Jersey, we don't want solar farms. We're too densely populated. We don't want them out there. We want the solar where the demand is. That's different than Arizona, Texas, California, where you have sun all the time, and we don't.

Moderator: Well, first of all, that assumes the technology remains static.

Questioner: Oh, no, it's definitely improving.

Moderator: Exactly. And as that improves, what you want to do is put into the market incentives to get more efficient solar production. And so what you get is more value. If you start the subsidy at a very primitive basis technologically, you're going to end up having to grandfather that, and you're going to get the issues that Speaker 2 was pointing out. Who's being discriminated against? Are these folks grandfathered? How much of it is grandfathered? What about me now? I want mine. Where's mine?

Questioner: In our solar industry, we started with 70% rebates. We stopped them probably six years ago. Those people are not complaining, who got solar. Right now, you don't get a rebate. You get your SREC. We created that, I guess, about five or six years ago. We've changed going along. You change based on the technology and the costs coming down, and it's worked in New Jersey.

Moderator: It depends on what you mean by "it worked." Does it mean you've gotten more solar? Yes. That's a pretty low threshold to judge by. I mean, if you throw enough money at something, you're going to get a lot of it.

Questioner: In New Jersey, we did not throw a lot of money at it. We, in fact, have a solar carve out, a solar RPS, and we created that because we didn't have any wind 12 years ago when I got a wind map done. So we did solar. It was the only option that we had, except for offshore wind. But it worked, and it's very cost effective. We didn't do feed-in tariffs, because that was not good. It just didn't make any sense. And we eliminated the rebates, and it's actually quite cost effective now, where the solar renewable energy credits handle it. I do think New Jersey needs to gradually do away with net metering, and I wish California would do it first, so we can see how it works.

Question 10: I have sort of a related question. Some of the objectives for installing solar are not strictly about energy prices and electricity prices. There are other objectives that explain why states have pursued this. We've talked about environmental objectives. That's one of California's main reasons. There are economic development reasons, etc. One of my questions for all the panelists is, when you talk about avoided cost, what are you including in the avoided cost calculation? Is it strictly electricity? Are the environmental benefits, the locational benefits of distributed generation, what have you, part of that evaluation? And that's one thing that I would say that Minnesota tried to do in doing the value of solar analysis, was to look at all the variables, not just the cost, but also the benefits, and they listed them out, and it wasn't strictly an avoided cost in the traditional sense of the definition.

Speaker 2: So if Speaker 3 is right, and these net metering distributed generators are under PURPA, if they are QFs, avoided cost means that they would be compensated for their energy

and their capacity contributions. And FERC has been clear that you can't require QFs, for instance, to convey their renewable energy credits back to the grid or back to the utility to retire them, and I suppose if you were, say, doing what New York is doing and investigating distribution-level markets, you could try to infer separately either costs or benefits, depending on your point of view, to the grid that redound when you add distributed generators. And the point of view on that would be that there are some grid benefits. Other people could say there are grid costs.

But you're right, avoided cost as a legal term is not as expansive as to include the broad umbrella that inspires states to pass RPSes. I mean, I would just say that, and this goes back to the RPS discussion I tried to have, these laws are so schizophrenic, they don't know what they stand for. Are they job creators? Are they favors to the unions? Are they for diversification of fuel resources? Are they to save the planet? And, you know, every state's is titled differently. Montana's has the name of the "Renewable Energy and Rural Economic Development Standard." And it was sold as something that would benefit farmers and the rural community in Montana.

And so this is the problem. On the one hand, if you were just very clear that the reason why we're building renewable energy is because we're out to save the planet from greenhouse gas emissions, then it would be easy, perhaps, to quantify the avoided carbon and compare the cost of avoiding it with other, say, carbon mitigation strategies. But these laws are just perfect examples of log rolling that turn into these unwieldy mandates under which all sorts of interest groups' desires are fitted. So, no, that certainly is not part of avoided cost.

Speaker 4: Just to tell you the world I live in, where the rest of the country is reveling in the fact that you can now shut down coal plants and replace coal power with gas, in California, gas

has become the new coal. And in this world, with respect to solar, there are a number of people in the environmental community that are going after large solar guys, because they're not as cool as the little guys. So, I mean, go figure. But that's the world in which I live.

The reason that I originally got interested in this is, why are larger solar producers getting paid five cents or six cents per kilowatt hour, and somebody who has got rooftop solar is getting paid something different? Now, there may be other values associated with that. There's REC credits to go with that. California's got a property tax exemption for solar equipment. I mean, there are a couple of other ways that you can come at the same problem on a state level. But that's, at least, the way I've been thinking about it. It's kind of on an energy level. But it is getting pretty frustrating, because, as I said, I used to think I was wearing a white hat, doing all the good things by encouraging renewable resources, only to find out that the Sierra Club really doesn't like me [LAUGHTER] because I represent those evil large solar guys.

Speaker 3: I just wanted to make the point that avoided cost is defined in the statute, and the Supreme Court has addressed the issue, and it is energy and capacity. So any environmental payment that would be made would have to be made under a separate law.

Question 11: At least two of the panelists have suggested an unbundling regime in which power that is purchased from the grid pays the retail rate, and power that's delivered to the grid gets paid at the wholesale rate. In California, in addition to the net energy metering and renewable portfolio standards and everything else, we also have a mandate on the IOUs to procure 1,325 megawatts of energy storage. So the question is, how do you believe we should be dealing with energy storage? What are the jurisdictional bounds for the power that you take from the grid in order to put into the device, and the power that you put out of the device, because

clearly buying at retail and selling at wholesale is not consistent with energy storage, whether it's in front of or behind the meter?

Speaker 1: You're going to have to pay me for that answer. [LAUGHTER] We actually dealt with that issue, at least in the context of compressed air storage, and our decision was that if you're drawing power off the grid to store, then it's a wholesale transaction, and you didn't have to pay any ancillary service cost or any of the retail charges, and you'd be charged the local LMP, as opposed to the zonal price on that. And so we treat it as a wholesale transaction, the storage, if you bought it for resale in the wholesale market.

Speaker 4: Yes, because I think that you're raising a point that I know we're arguing about now in California. So what is storage? And a couple of years ago I was on an air resources board advisory committee. We identified storage as being a major game changer. And at that time we were trying to move wind from the nighttime to the daytime. So now this is a totally different issue. But people are having a really hard time determining what storage is. I mean, it's Tupperware. It kind of depends on what you're putting in it. Right? So there are people arguing, "Well, it's automatically a renewable." Well, that's not necessarily true. I've got a great picture in my office of an AES plant in Chile that's got a coal plant in the background. They're using the batteries basically for local system support, so it sort of all depends. And then if you put it on a distribution system, is it actually providing the distribution services? Or are you storing electricity coming from some other place? I know, years ago, AES had a two megawatt battery package sitting at the Huntington Beach station, and nobody could figure out what to do with it, because we couldn't answer the question. ISO couldn't figure out, well, what is it? Do we tie it into the grid? Or is this Edison's responsibility?

Speaker 3: Well, let me just ask the question. How is storage any different from pumped storage, hydro? You're using another generator to take in energy that you can then discharge at another time. FERC views it as generation.

Questioner: Well, one difference, which isn't really relevant to this discussion, is that pump storage hydro is ineligible under the California requirement to procure the 1,325 megawatts. But that notwithstanding, I'm not claiming that there is any difference. I am saying that it's even more complicated to make the argument that unbundling is clearly what's appropriate, because when you buy, it should be at retail, and when you sell, it's at wholesale.

When you say that if you're buying it for a particular purpose of storage, then it's different, and it's actually a wholesale purchase, I'm just having trouble reconciling all this, even though I absolutely believe that if we're going to go forward with storage, it's got to be purchased at wholesale and sold at wholesale. It's the only thing that makes sense. But I don't know how that reconciles with the logic for unbundling for distributed generation. And I'm also wondering, when we talked about the backup generators for Texas, are those also in a second separate meter buy all, sell all model? And if not, why not? You're deciding that it's somehow different if they're claiming to be used for backup generation as other uses on the grid? Is there a distinction there? Or is the model in Texas also applied to backup generators?

Speaker 1: The backup generators actually, if they're put in for backup, well, it means they're supposed to have a device that keeps it from backflowing, and it predates, actually, all this. You have to go to safety. But the problem is a lot of folks who had it installed in their homes, the electrician doesn't do it, which is why the distribution utilities are concerned about it. But, in theory, you could do the same thing, and there are some companies that do. So they're not putting the generation onto the grid, but it's still

DG. What they're doing is severing their connection from the grid, and self-supplying in that case, and again, at that point, what is it? Is it DR? Or is it DG?

Questioner: And if it's DG, do you apply the same rules that basically say, you have to sell it all into the grid, and everything you purchase is at retail?

Speaker 1: Yes, if it was going on the grid, yes.

Speaker 2: You know, I think storage is certainly a much more difficult thing to value than, say, the non-firm energy that a distributed generator would produce. The latter's production fits into a more well-established and homogeneous and liquidly-traded category of energy, whereas the types of things that storage provides are things for which even organized markets might not have a market product, and which fit into multiple market product categories, whether it be the kind of fast-reacting schedule three stuff that Order 755 envisioned, or a sort of flexible ramp product like CAISO is discussing. I can't and I won't endorse what California is doing. But let me give some tepid praise for it, which is, if there was ever an energy product which invited the command-style decision making of California, as opposed to relying on a market to surface it, it might be something like storage.

Questioner: And I don't expect you to address this wholesale, retail, jurisdictional question, but it's even more complex in storage when you consider that some storage is potentially multiuse. In other words, sometimes you may use it as transmission or distribution, and other times participate in the market with it.

Speaker 4: And wait, there's more. I got myself uninvited to an energy storage meeting once by making the following observation: who gets the REC? So when my wind generator basically sends it to the battery, they want the REC. Well, the battery guy's going, "Wait a minute, no, I

get the REC." Or maybe we have two RECs. So we all get credits for it, which you obviously can't do. So just pay attention to California. We are the nation's lab rat. So we will look at this in every possible way we can, and there's at this point no answer to your question.

Question 12: I appreciated Speaker 4 taking us back to wheat. But I guess the one caveat I would have is, I wonder if the Supreme Court of today would reach the same decision. My observation is, if healthcare is not interstate commerce, I can't imagine home grown wheat is.

But the other observation I had was, there have been a number, I guess five decisions, four in district courts and one in the Court of Appeals just last week, telling states that they don't have the authority to order and compensate generation because it interferes with the FERC jurisdictional capacity market. Is that not relevant to this discussion? I think in some respects it is. One of the cases addresses Minnesota's RPS, or Minnesota's efforts to end their use of coal. It says that Minnesota can't do that, because that's effectively regulating North Dakota's consumption decisions. And then you have one in Colorado that says that it's OK for Colorado to restrict use of coal, because it is not regulating, say, Wyoming's decision. Those decisions, to me, are all over the map. I have some observations about what makes them different, but I wonder what your thoughts are.

Speaker 3: I think they support my argument. Wholesale is wholesale, retail is retail. And you can't call something that's wholesale something else and get away with it. But the facts are different. I mean, these jurisdictional cases stand on their own. All I can tell you about the New Jersey and Maryland cases is that the right team won.

Speaker 2: So why would a state have the authority to order the construction of renewable generators under a renewable portfolio standard,

but not to retire existing generators, or do something else regarding the generation mix?

Speaker 3: I think the problem here was that this scheme involved bidding the unit into the wholesale capacity market at a pre-established price as part of a scheme to reset the value of capacity for that generating unit and putting it in a separate category with everybody else that was in the market. And so it was a direct attempt to price capacity through a state law. Do I have that right?

Speaker 2: I think so, but the only observation I would have to respond to that is that FERC developed rules to handle that. So the court could have said, “State, you have all the authority in the world to build generation. FERC has all the authority in the world to protect its wholesale market.” What’s the problem here?

Speaker 3: I don’t think the court intended to say that the state couldn’t build generation. I think the problem with this scheme was that they were paying them a specific proprietary, guaranteed price for their capacity, which interfered with the operation of the FERC-jurisdictional capacity market. That’s what the preemption issue was in that case. I think states have the right, they’ve been doing it for 50 years, to approve generation projects in their state or not approve them. That happens all the time, and I don’t think anyone’s ever suggested that that’s inconsistent with the Federal Power Act, or is preempted in any way.

Question: I didn’t think the states should set that price. I thought it was dumb to put it in the contract. It was done anyway. Now, do you think, if the price wasn’t in that law, that we would not have gotten defeated?

Speaker 3: I’m not the right person to ask. But based on what I know, yes. I think you would not have been defeated...I’ve got some people here telling me I don’t know what I’m talking about, which is not the first time.

Speaker 2: The other reason the Court of Appeals cited was that it wasn’t only the fact that the price was established in the contract. It was the fact that the contracts of both states required them to clear. So, as I think Speaker 3 correctly said, each of these cases falls on the facts in each case, and it was the combination of the fact that it was a contract for differences and the fact that they were required to clear. It wasn’t just that the contracts set the price for the particular plant that got the contract. It was that the effect was to then affect all the rest of the generation in all the other states in a multistate jurisdiction. That’s at least the way I read the case.

And to Speaker 3’s last point, the states do have and retain the traditional regulation over generation, because there was some concern the District Court had kind of gone too far in how it explained its rationale, and we were very clear to say, “Hey, the state still has all the power the state used to have,” but on these particular facts, it was the right result.

Question 13: On the DG debate, I would agree that the more we get into it at an earlier stage, the better. And I think we have 22 states now that have some sort of docket opened. And it’s pretty broad. State statutes vary. My state in particular offers a very rich package to in-state solar generation. It gets up to 54 cents a kilowatt hour if the panel is procured within the state. It’s only 14 cents or so if it’s outside of the state. We have all these commerce clause issues, but I don’t think they’re going to be raised. So I think it’s a good thing to get going.

Speaker 3, to your point, if the federal government tries to take DG over, there’s going to be a big reaction from the states. And I think that would be a foolish thing to do. NARUC leadership has been in touch with the Department of Energy, because we hear that Secretary Moniz and his team under the QER (Quadrennial Energy Review) may want to look

at distributed generation. And we don't like the way they're going, and if you come up with some innovative legal argument to take away our jurisdiction, that will be interesting, but that will be kind of a big fight, I think.

My question for the panel is really 111(d). I think all of this is kind of irrelevant now in one sense, because we have a national energy policy, 111(d), now. That's kind of the law of the land, because Congress probably isn't going to act on the Federal Power Act thing. So my question is, you have these four building blocks in 111(d). You know, you have reduce within the fence, economic redispatch, renewables, and then you have energy efficiency. It seems to me that if DG and DR are encouraged by EPA, maybe with the blessing of DOE and FERC, to be clean, to be non-carbon emitting, this could have a pretty significant impact on how the states develop their plans, with corrective action or some sort of enforcement from the EPA. So do you have any thoughts on that?

Speaker 2: A couple, I guess. First, you know, the resource planning that has traditionally been the province of states, state utility commissions or sometimes, in the context of transmission, RTOs, may now be the province of state air quality regulators. How funny is that? And there are two broad sort of approaches that one might see states take. One is sort of what California has done, and I'm going to praise California now. AB-32 is setting up a liquid carbon trading market that surfaces the most cost-effective carbon reducing actions, whatever they maybe happen to be. The other is going to be an approach of central planning, because a governor of a particular state may say, "Oh boy, I've just been handed by the EPA a huge taxing opportunity, or job creation opportunity, or whatever. And we're going to comply with this EPA mandate by saying, 5% distributed generation over here, a wind farm over there, a solar project over here, a new gas plant over here, and retire that coal plant over there, and compensate them something, too." That will be,

for many states' political establishments, an irresistible temptation, no matter how ridiculous it is. If the rule stands as proposed and is substantially the same in its final draft, yes, there's going to be this log rolling process all over again, and the craziness of state renewable portfolio standards will be in a distant second place to the potential craziness of state 111(d) plans.

Question 14: This morning I congratulated the policy group on the 75th meeting. It is amusing, distressing, disappointing, and frustrating to hear questions relating to a national energy policy program today, 75 plenary sessions after the first one, when I think certainly within the first five meetings we had the very same discussion, and the very same frustrations that there was not a plan in place. And now we have what we have because there's never been a plan in place.

It is actually somewhat amusing to hear that "avoided cost" is a judicially defined term, where there are at least 50 different incarnations of avoided cost around the country, ranging from whatever the cost happens to be in any hour, to whatever the cost happens to be of capacity and energy from a certain kind of generation over a year, to reference plan costs, to God knows what else. And it may be judicially defined, but it certainly has not been handled as a defined and sort of generally accepted term in the business, and that has been a problem for all of the generators and all the people who are dealing with how to measure the effectiveness of various different kinds of additions to the grid, whether they be DG, DR, utility scale, etc.

Speaker 3: I agree with the avoided cost part, and a good avoided cost methodology will sort of inveigle environmental considerations into the avoided cost. For instance, it will ask, what will be the price of carbon's effect on wholesale energy market prices in year five, and as a long-term avoided cost rate over 20 or 25 years, it

will attempt to approach those questions and get to a price.

Speaker 4: In California, we obviously had great avoided cost calculations back in the '80s. Thank you very much. And that put all my kids through very nice schools, and we used to argue a lot about that. But what we moved to now, this is kind of, I think, an important distinction, is our renewable folks now have to pretty much compete against each other. So that competition is driving what it costs in the RPS, which is why you're getting six cent solar. Again, I don't know if anybody's making any money in that business. So it's driven in that way. And I also think that this, if we're not reinventing anything based on Speaker 3's analysis that these are PURPA QFs, it does leave the states free to kind of figure out how they want to calculate what the value of net energy metering would be in terms of pricing. But we'll see.

Question 15: Speaker 3, help me think about the DC Circuit Court's decision. It could be quite circular. So let's just say it's upheld, just hypothetically, and DR moves to the states. And now demand response is not a supply side resource, but is a demand resource and shows up as price responsive demand, impacting forecasts, load predictions, and that curve. It's aggregated by utilities and bid into the ISO under business rules. Now you have utilities aggregating demand response and bidding it into an RTO, impacting and relating to the wholesale clearing price. Doesn't that also throw it right back into federal jurisdiction, after it just got relegated to the states?

Speaker 3: Maybe it's late, but that went over my head.

Questioner: We'll talk about it at drinks.

Session Three.

Cyber-Security vs. Physical Security/High Voltage vs. Low Voltage: Which Should Be the Priority?

With growing demands for increased grid security, there is a growing tension between demands for greater physical security of network facilities and upgrades to protect against cyber-attacks. These demands must also be seen in the context that most service interruptions are experienced on the low voltage, distribution, systems that are highly vulnerable to environmental and other challenges, while the mega threats envisioned by national security advocates are at the system operations or high voltage, transmission levels, and/or at large generating facilities. While both levels merit concern, which should have priority for the industry and for regulators? What are the metrics for measuring the cost-effectiveness of investments in security? How should regulators respond to these competing demands in terms of cost allocation and recovery decisions from customer classes with differing needs for secure supply? What should be subject to government mandates and what should be left to the discretion of the industry?

Moderator: Good morning. Our topic on cyber security versus physical security raises a number of questions. Mainly, how do you allocate resources? It's really about, where do you allocate the resources and what dangers do you perceive to be the most threatening? And I would just throw one question out, which is, if an outage comes from just a simple thunderstorm on your block, is your electricity any more or less out than if the outage comes from an asteroid or a terrorist attack? If the electricity is out, the electricity is out. So that gets to the question, where do the resources go?

Speaker 1.

OK. I'm going to try to do what the moderator just said and try to talk about these threats, and try to put them in some kind of perspective, and then talk about a little policy stuff.

I've broken the threats down, into natural events and human intervention. And you can read these. We all know about weather, and as the moderator said, that's what we're used to. We're used to thunderstorms, derechos, tornados, ice storms, wind storms, hail, fire, and whatever else we see.

But now the electric industry is being asked on an unprecedented basis by the regulators to look

at human intervention threats. And since we know what a lot of these things are, I'll take a few minutes to try to explain some of the things that you don't know.

This chart was prepared by the Chertoff Group, the head of which is former secretary Chertoff. And it tries to put these different types of threats in perspective of likelihood and consequence. And if you look at the thing that has the biggest combination of likelihood and consequence, surprise, surprise, it's natural disasters. There are large consequences to nuclear attacks, CBI, and electromagnetic attacks. But you have to put all of these in perspective. These are the kind of things that can disrupt the electric system, and policymakers need to discuss these things because there are costs, there are consequences, and there are cost consequences.

I'd like to talk about a couple of things you may not be all that familiar with. Space weather. We all know about regular old weather. We had some tough weather in the east this winter. This is space weather. Solar flares, solar magnetic disturbances. The problem is, you can't see what's happening. So I'll try to show the part you can see. On the left here is something called a coronal mass ejection. That's when you have the solar flare and the sun spits out a bunch of highly-ionized particles. And what can we see? What we can see is what you see at the right. It's

an aurora. By the way, there are also auroras in the south. They happen to be called aurora australis, rather than aurora borealis. But it happens at both poles.

Here's what happens. You get this stream of ionized particles, and it hits the wonderful magnetic field of the Earth, which protects us against all sorts of bad things. Well, it interacts with the magnetic field, and just to put it in the simplest manner, the way we generate electricity is you have a moving magnetic field and you have wires called transmission lines. You induce current in those transmission lines. And that's the threat that we're talking about.

Physical security. This is public information. In fact, it's from the *Wall Street Journal*. It gives a timeline of the attack at Metcalf Station on August 16th, 2013. It was a sophisticated attack, and Speaker 3 will talk further about that.

Electromagnetic interference. This is a picture of a fictional device. Note the source, Ocean's 11. OK? You all saw the movie, right? Basher, you know, he triggered this thing and the lights went out for 30 seconds. That's fiction. That's not what would happen if you had a device. But here is a picture of something that is purportedly a real device, which somebody carried to a conference in London and somehow got it on an airplane. (They ought to think about TSA security). But, yes, he got that on an airplane. It creates a high electromagnetic field.

Next, this is actually a picture of the aftermath of a nuclear explosion out in the Pacific, taken from Honolulu in 1962. They had flickering of lights and they had other impacts on the island of Oahu. And that was the first time that they, at least in reality, I'm sure the physicists figured this one out, that they saw the effects, the electromagnetic effects, not the bomb effects, on the electric system of a nuclear explosion.

This is the one that people tell you, "We're going back to 17th century." It's called high-altitude electromagnetic pulse, and there are people running around Congress saying, "Watch out for the North Koreans." And that's purportedly the real threat.

What we're talking about is a detonation at altitude 30 miles, 40 miles, somehow it's either over Omaha or Columbus, and I don't know why. I think Columbus because its line of sight is such that somebody determined you can get the maximum number of customers. You have several impacts. The first one--there was a movie in the 80s, *The Morning After*, or something like that, with Jason Robards, you know, and they see the explosions over Kansas, and all of a sudden the cars stopped running. Well, that's what you see. All the electronic stuff gets fried. That's that threat. The other threat, the E3 Impact, is similar to the solar storm.

So these are some of the threats, whether they are probable, whether they are likely, whether they are preventable, that are being brought up by numerous people who are telling us that we need to consider them. No one's talking about funding. No one's talking about what it's going to cost. No one's talking about the fact that there's a large department of the federal government that inhabits a five-sided building that has certain responsibilities. But that sets the stage.

So what are the effects? Well, I think we know weather. Generally wind storms affect the distribution system. That gets real personal. That takes out customers.

When you start getting into space weather, that can affect the high-voltage transmission. And these other cyber attacks, physical attacks, can

affect the entire system. You can read the next slide. These are some of the NERC standards.

The only thing I have to add is, for geomagnetic disturbances related to space weather, the operating standard EOP-010 is on the FERC agenda for next Thursday. I expect FERC will approve that standard. But standards can't do everything. There are lots of other processes. We have information sharing, so you'll hear the term ES-ISAC (Electric Sector – Information Sharing and Analysis Center). We have emergency response teams, very, very smart people who understand the cyber stuff. And, you know, we do have physical security at our stations, in spite of what Congress may believe. We do not really want our stations to be destroyed.

So, resiliency and restoration. Let's just assume you can't prevent everything. Because you can't. One element is the Spare Transformer Equipment Program. It's an asset-sharing program with 50 utilities sharing transmission-to-transmission transformers. Spare Connect would be a voluntary program for other spare equipment.

Utilities are working on transformer transportation. I assume most of you have seen big transformers. They are big. They got to be moved.

There's a Recovery Transformer. It's been a DHS/EPRI project to be able to take these things and move them very quickly, say 20 hours from St. Louis to Houston, and have them energized in five days.

And then another part of resiliency and restoration is incident response, which a good example of was what was seen during Sandy.

Priorities. As I said, at the distribution level, you see the outages. But the high-impact, low-

frequency transmission events, that's the stuff that's new. And what do we do about it? How much money do you invest? What should come from the federal government, where things are national, really national security? And then a three-legged policy, prevention, resiliency, and restoration.

So what do we do? Well, we have to work together. This cannot be utilities by themselves. There are lots of policy decisions that have to be made. We don't collect intelligence. We run systems. The government collects intelligence. Of course, there is this little problem that very few people have access to classified information, and if you have access to classified information, you may not be able to tell your CEO, which is a problem. In our case, our CEO and other people do have the clearances. And that's a government program, too. So we need a balance. I think lots of us said, "If everything is a priority, nothing is a priority." We need to establish priorities, what we do and what we fund.

And then cost recovery. We look at the distribution risks. They're very frequent. They affect all the customers. But if you start going toward, for example, physical attacks, you can't protect every distribution substation. You need to be able to say, you know, we're going to recover. At Commonwealth Edison, and I suspect other places because of where you locate stations, we've had floods. And floods have taken out substations. And so you rebuild them. There's nothing you can do. You've done it. We've done it before. People did it with Sandy.

You have to be able to have a resilient system, and be able to recover. What's new are these transmission risks--as I said, the high-impact. I think we need a balance: prevention, resiliency, restoration. And we need a, I hate to say it, national policy. We do need some national government-industry cooperation. Where are we

going to put our money? What are the biggest threats? Who are going to be the actors? And it needs to be done without the shrill, the world is coming to an end rhetoric that puts aside worries about what it's going to cost. Because, in the end, the rate-payers will pay.

But in the end, we want a system that can withstand even the worst reasonable attacks. Because, you know, speaking now not for the company, and maybe not even for myself, but we don't want a situation where you have outages of electricity for months. That's unacceptable. It's unacceptable to the country, and it's simply unacceptable. And the only thing I can say in the end is, when our backs are up against the wall, we find ways to do things that you wouldn't necessarily think we'd do, even if it means laying cables on the ground and keeping people away. So I don't know if I've done my job in scaring you. Hopefully a little education and some thought. So, thank you.

Speaker 2.

Thank you. I'm a technologist, now working significantly in the public policy school. And I think the cyber area, including the energy area, is one of the areas about which I think we have to think ahead. It's an emerging threat, and trying to understand that is important, because too often we establish the policies after the event. And this is really my main message.

And the second main message is that actually this field is highly interdisciplinary. The technologists have to be actively involved, as well as the political scientists and the public policy makers, and you've got to bridge those divides.

Let me give you an example. When I joined the Belfer Center five years ago, it had a huge and extremely influential program in national

security policy. It was well known for its work, it starts with many of my predecessors, Graham Allison, and others. And of course, the biggest threat is the nuclear threat. And there it is well understood that you have nation states, you might have to worry about North Korea or Iran or the Russians, as in the past.

And until 9/11, we didn't realize there could be a very game-changing threat, namely, terrorists. And then seven years later, Mumbai was in India's 9/11. So it got repeated in a different way with serious consequences to the psyche of the country. Very often when I talked at the Belfer Center about the international security cases, the perception was that cyber security is not something so important, the real threat is nuclear and so on. So to bring this issue to the forefront is, in my view, an extremely important thing.

In the cyber area, the actors are not necessarily state actors. There are brilliant computer scientists, I can tell you, all over the world, in Eastern Europe, in China, in North Korea, in India, Russia, whatever. And there are bad guys here, too. And so one has to be aware that there are an enormous number of non-state actors, and there are always evil guys out there, most of them. So that's point number one.

It is a highly interdisciplinary challenge. And in this area where energy and information technology meet, because of smart grids, because of various information technologies becoming all-pervasive, including banking, etc., and also for the increased use in renewables, the system might become much more distributed than central.

And my two research fellows here in this room, who actually looked at this intersection between energy technologies and the cyber area, they recently pointed out there was this editorial in

the *New York Times*, “Smarter Electricity in New York.” And they said, the distributed system will be very good. It will reduce some of the physical effects, etc. But in fact, you have to worry, because when you do that, the cyber threats may increase. So somehow those will have to be balanced, since this is one of the areas we want to talk about.

Hurricane Sandy was a big event in the Northeast. I have a son who lives in Summit, New Jersey. And he had no power for 10, 15 days. He has a home on the shore. Only his house was left standing and the entire block was destroyed. So the take-home was about the lack of resilience in the system. I wrote an article with another post-doc, “4 Ways to get Phone Service the next Time A Hurricane Sandy Calls.”

My past was at Bell Telephone Laboratories. Whether you liked Bell or not, the telephone system always worked. It was reliable. And even when the power went down, the phone system had its own electricity. In fact, I still keep two old line Bell phones in my house. I have a house on the Cape, and we have lots of power outages. Because I know my cell phone will not work, but that little phone which is plugged into the wall will still have power.

So I got very upset when I heard, not just about the power outages of Sandy, but that many people could not use their phones during Hurricane Sandy. What really upset me was, Verizon, all of them grew out of AT&T. Verizon, AT&T, all these companies were Baby Bells. But then they decided to forget their origins and build systems which couldn't talk to each other.

So Verizon was on what is called CDMA, AT&T was on GSM, and the Verizon people could no longer talk to the AT&T people when

Hurricane Sandy happened. It was a serious issue. And these companies had assured the government, “Oh, we will have our systems, they are compatible, etc.” Oh no. AT&T and T-Mobile got together, because they could work with GSM. And so T-Mobile and AT&T subscribers could work, but not the others.

So this tells you there are some great issues of standards now which didn't exist before, and which were of serious consequence. During a disaster, communication is almost the most important thing. And, of course, you have to put out the fire, and know where the fire is, but the communication... So I want to lay the groundwork here that we all know best, everyone, there has to be some kind of proper partnership between government and industry.

I want to summarize what is known and what is unknown. The knowledge about cyber security is limited and provisional. Information and communication technologies are central to the provision of electric power. When Secretary William Lynn, he's the Deputy Secretary of Defense in the first Obama Administration, came to give a talk at the Belfer Center, he said, “My biggest responsibility is the infrastructure, obviously.” And this is the defense secretary. He said that the civilian infrastructure is his biggest responsibility and that's where he saw the cyber issues to be extremely important.

The electric power grid will remain vulnerable to cyber attacks and cyber exploitations. And one of the key things is zero-day malware. I don't know how many of you have heard of zero-day malware.

It's a huge issue, because they are of course unknown vulnerabilities. And cyber attack can cause physical damage. It's not just taking the money from the banks, which is important, or taking the credit cards...when Stuxnet

happened, that was a huge, huge effect, because everything is computerized--in fact, the controllers for the Iranian centrifuges. Centrifuges are the stuff which purify the uranium. And those centrifuges spun uncontrollably because somebody infiltrated the Iranian system. We don't know who. You can guess who it was. And there's a country out there which actually is very good in computer science, one of our great allies. And so that really gives you a wakeup call that you could in fact affect, through the Internet of things, the controllers and the smart grid in unknown ways.

And our reliance on this technology will continue to grow. I mean, we're not going to have an argument about whether it is going to be centralized or distributed. I actually believe that ultimately it'll be some kind of hybrid. We don't know exactly how, but this reliance on information and communication technologies will grow.

What is it that we do not know? What is the likelihood of a disruptive attack like a 9/11, like a Mumbai? We know terrorists can do this. And Stuxnet was almost that for the Iranians, right?

What is the upper limit of damage? These questions are all important, because ultimately we have to balance the costs with the risks. And how will capabilities of different actors, non-state actors, change in the coming years? That really is a huge issue, because not only do we have to have standards within our country between the government and the industry, but also we have to have norms which have to be established internationally.

And this is still a very important area, and right now India, China, Russia, the US, and the European Union, all the major players, all have different views on how this needs to be done. So this is just from the point of view of

international threats. And, of course, locally as well. We are currently still deciding what the rules of the road should be for next generation communication systems.

So my job, I feel, is really to keep thinking ahead of the future. That's what the labs taught me. And I really believe it's extremely important in this area that the electric utilities are so important, along with the telephones. You can argue which is more important, but if you have a fire and no power, you know, you're sunk. OK?

Cyber security is, in fact, an interdisciplinary challenge which needs to bring all of these different groups: computer scientists, electrical engineers, social scientists, and lawyers together. I have struggled within the university alone to actually make sure there are ties between the Kennedy School, the School of Engineering, which has outstanding computer scientists, and the Law School, which has people who really think hard about what the policies should be.

And, in fact, that's beginning to happen, because this is really important. So the fellows are much of the bridge, and I really would like to encourage industrial partners and overseers to think ahead and to try to bring the different communities together. And this also includes government-industry partnership here. Because it cannot be by the industry alone, obviously. It can't be top-down either. It is a different kind of technology, and we really have to learn to do this in some way and set the ground rules.

So that's most of my talk. And let me just end with a few other slides.

The search for metrics: fuzzy terminology, conflicting interpretations, and setting standards. Because there are many unknown features. General Keith Alexander, who actually came

and visited the Belfer Center a year ago, he was head of the country's Cyber Command. (The Defense Department does have a big Cyber Command, and Keith Alexander, until about six months ago, was the head of it. And he said, "Every day, America's armed forces face millions of cyber attacks." That's what he claims. And people challenged him.

And of course you can argue about what is a cyber attack, how consequential was a given cyber attack, and how do you know? All of these are not crazy questions, because people can come into your computer surreptitiously, in the dark, and get out without leaving any trace. And that's quite common. The computer scientists know that. Because the attackers are trying to find out where your vulnerabilities are, waiting for their moment when they will actually come and attack you. So whether to count those probes as attacks is one of the disputes. In fact, that's part of the issue with zero-day malware as well.

Discovered vulnerabilities: what next? How significant are discovered vulnerabilities? What quantity of limited resources should we deploy to manage this risk from discovered vulnerabilities? You want to have some leading-edge people in that field--you don't have to have a huge army, but people who understand it so that you actually are prepared for that zero-day, for the 9/11 or the Mumbai event.

Governing emerging technologies and evolving risks. It is a crosscutting challenge. We need to invest in security, but how aggressively, and when? My post-doctoral fellow, Ryan Ellis, has written a paper exactly on that progress in the standards which we're trying to work to set up between this industry and the government in a collaborative way, and that's actually an important first step, and you people know much more about it than I do.

And then at the same time you need to have people at the leading edge, because ultimately you do not want to have that 9/11. The complex questions need involvement from a broad set of disciplines. The computer scientists. Technologists, I know (I was dean of the School of Engineering) are fascinated by that technology. That's what gives them the kick. But they need to realize all of the other consequences, and vice-versa, too many of our policy leaders do not have any feel for that technology. And of course, that divide has to be crossed, and that's what we're trying to do here.

So I wanted to mention that now at the Belfer Center, I've worked hard to create a cyber project. We bring in research fellows from different disciplines and actually have finally had papers published in the *International Security Journal*. You don't know what a headache it was to get it, because people didn't believe it was any threat comparable to the nuclear arena. And now it's slowly being recognized in that arena.

And the same thing needs to happen in this kind of arena, where these fellows work with people who understand the electricity industry. You are the people on the ground. I always want to connect theory with practice. So it would be very great if we can develop some of those interactions, because this will be important. So we are creating right now an executive education program at the Kennedy School, it's inaugurated from this July, which will actually try to bring leading people here. We've got some scholars between Harvard and MIT, and at Harvard we have several people working in this area now.

Because I'm convinced that our public policy leaders really need to know. And we're getting a lot of applicants coming in this area. And we might want to concentrate some time in the electricity area. It is important, even though we

don't know all the facts. That's the time to prepare. You don't have to put enormous resources like you might want to do against Hurricane Katrina or something else, but you do want to be prepared, because of the fact that the Internet of things and cyber are coming close together.

So the conclusion, then, is that cyber security is a public policy challenge. It is highly interdisciplinary. And we want to bring these different groups together, both the theory and the practice, the social scientists, the policymakers, lawyers, and the computer scientists, together in actually addressing this task. It will require all of that. And we know Target paid horribly by what happened when it didn't pay attention. Wal-Mart didn't. And I really hope the electricity doesn't go down. I know how much my son suffered in New Jersey, and we took care of all of them in the house in Boston. And so we do want to be prepared. There are examples where the cyber has had serious consequences. Thank you.

Speaker 3.

Good morning, everyone. Thank you so much. As Speaker 1 mentioned, part of what I wanted to focus on was talking about what happened in California with regard to the PG&E incident at the Metcalf substation near San Jose, and how this addresses the issues about physical security, cyber security, and interdependencies, including the communication system.

The Metcalf substation is right next to San Jose, California. It's technically in south San Jose. So it's right off of highway 101. And so it really is an important substation going into the Silicon Valley.

And when you think about California, we have three of the top ten largest cities in America: Los

Angeles, San Diego, and San Jose. San Jose is a larger city than San Francisco, and, of course, is the home of Silicon Valley, which really starts from San Jose, although Santa Cruz would also argue they're in the Silicon Valley, and goes all the way up the peninsula, and then increasingly we have a lot of Silicon Valley assets in San Francisco. So this station has now been identified by PG&E as a critical substation.

So I think one of the lessons is to do threat assessment and vulnerability assessment. And that was also one of the directives from the FERC order that followed this particular issue, in terms of hardening physical security as well as addressing cyber security, is to first and foremost identify risk.

So, given where this substation was located, it is an important station. But you can also see from a little bit of the map, you know, that this is very different from a station right in the middle of the city. It is in a more rural area of San Jose that is on the way to Gilroy, if you've ever had the opportunity to go to the Gilroy Garlic Festival and have the garlic ice cream.

And I mention that, too, because there are a lot of coyotes in this area. There's a reason why San Jose has more cowboy bars than San Francisco. And I also mention that because it is not unusual for people in this part of San Jose to have guns, in part because of the coyotes, and whatever else they do. And so it actually took a while for reports of gunfire to actually start coming into the station. And right next to this particular station, there's a ranch where there's cattle grazing. So cattle would come right up to the fence.

So one of the things that's important about the Metcalf incident is that this really demonstrates the intersection that Speaker 2 was talking about between communications and electricity, but in a

different way. Because the first thing that these people did (and, again, I'm repeating things that were both on the news in San Jose the morning after the attack and much later in the *New York Times*) is they cut the AT&T lines.

And for any of you who also are told, "Oh, we're building a whole new network and the cell phone network, or the VoIP network is a whole new network," this demonstrates it's one network. So some people opened up the manhole, cut the AT&T lines--I won't go into exact details about how and what they cut, but they managed to cut the whole shebang, right? Plain old telephone service, cell phone service, Internet service, everything. Then they went to another nearby manhole, and they also cut the wires for Level 3, which is one of the very important middle-mile Internet backbone providers.

Now, these people still have not been caught. AT&T actually has a reward that's out, the FBI is actively investigating, PG&E has been cooperating, of course, with the investigation, as have been local police. And they've not been caught. So one of the questions is, what were they trying to do with cutting communications services? Were they simply trying to cut the visibility of PG&E into its substation? You know, were they trying to really address the ability of the electric system to understand what was going on? Or were they really trying to create both a blackout in south San Jose and a loss of communication services? Which is very scary.

It's also worth mentioning and emphasizing, especially since we're here in the city of Boston, that this happened the night after the Boston marathon bombings. So the marathon bombings were the previous morning, and then this event happened between about one o'clock and two o'clock in the morning the following evening.

Again, coincidence, or part of a more coordinated attack? We still don't know.

The fence alarm was then activated some time later. Then there was an initial transformer system alarm. So, luckily, in terms of resiliency, there was some backup that provided some communication to PG&E, and also alert that something was going down. And then, finally, police arrived on the scene when shooting was reported.

Again, it's been reported in the press, there were over 100 bullets fired into the substation. I have some pictures of the damage that was done. It's been reported that these were high-caliber bullets. I can tell the regulators in the room privately more details, although I know that the National Association of Regulatory Utility Commissioners, has gotten some other briefings for critical information threats. But let's just say, these people do not appear to have just been casual people walking by who decided to discharge their leftover bullets from the coyotes, right?

They were very careful, they had very sophisticated technology, they knew what they were doing, and they cleaned up after themselves, which had some benefit but also made it more difficult to catch them. So they did a great deal of damage to the substation. It cost about \$15.4 million to clean up the damage. And I'll show you some of the pictures of some of the damage that they did so you can see some of the bullet holes. They mostly, with the shots, managed to have a lot of oil drip out of some of the tanks, and so that caused various issues with regard to the cleanup.

They actually did not take down the substation. It continued to function, but it did power down to a lower level. And one of the things, also, to emphasize is, since this happened in the spring,

we were also lucky in terms of the timing, because the demand was low. It happened at two o'clock in the morning, and the next day was not particularly hot or cold in San Jose. We did have to do a demand response incident and ask people to conserve electricity.

And the other thing worth mentioning is, since they also cut the communications line, there were warnings to people. You know they had to put stuff out on the news for the people in south San Jose who lost all telephone service including cell phone service and lost 911 access. So on the news, you know, they said, "If you need 911, please walk to your nearest fire station, and here's the fire station. Or if you can, drive out until you can get a signal." They actually leafleted the area.

And then this is where it's important to know, who are your vulnerable populations? Often with electricity companies, they have lists of people who are medical baseline who might be on respirators or other types of things which need electricity. So even though electricity was not lost, again, these people were very vulnerable without communications. So this affected a very large part of the population of San Jose, but it really was a wakeup that while we were very focused on cyber attack, the old-fashioned physical attack could also do a lot of damage.

So in the aftermath, not only does the criminal investigation continue, and of course now we have new FERC standards, but we're also looking at what we can do. The FERC standards require us all to look at what we can do to promote physical security as well as to think about how we integrate this into our overall security and threat assessment. And so one of the things that they have done is also looked at putting shields up in front of some of the critical

infrastructure so that a bullet couldn't penetrate things that are really important.

Also, they are thinking about fencing, whether or not chain link fencing is really the right thing to do. But I would also suggest, in addition to physical barriers, thinking about things like lighting and cameras. And also, how can a light be more than a light? And there already are lights that are available, and some that are coming out and being developed, where you can embed things, like not only motion detectors, but cameras, in lights. You could also imbed a Shot-Spotter or some of its competitors, in lights, so that when a gun is fired, the streetlight calls the police. You could also set your lights so that if they detect a gun being fired, that the light would super-illuminate. You can do all of that through lighting. And through lighting, you can actually expand beyond the perimeter of your fence. There's even some lighting that also could incorporate things like detecting a mass of 100 pounds or more moving towards you. So you want to be able to filter out the coyotes and get in the people. (Although I was showing some people a picture of a recent trip to far northern California where I visited with the Yurok Tribe and the Karuk Tribe. So there, the bears weigh 350 pounds. So I have an ode to the California Golden Bear here. So again, you've got to filter out the bears.)

But physical security is very important. And FERC has been looking at this issue, as well as NERC.

One of the things that we look at in relation to security-related events reported to FERC is, how important are these threats? This is a chart of some of the reports that are made to FERC. The thing that is reported most is basically vandalism. Copper theft is far more common, in terms of being a security threat. In this chart, for

suspected cyber attack, there were only three reports to FERC.

Last night on the plane I was reading a book on cyber security and cyber warfare which also said that if you're a Fortune 500 corporation and you haven't reported that you've been hacked, it's just because you haven't discovered the hack. So, you know, there are a lot of vulnerabilities with regard to cyber security. Certainly there are a lot of bad guys out there.

When I visited with the Diablo Canyon Nuclear Power Plant, they were saying that one of the benefits of the way that that plant is designed is that the road between the main access point and the reactor is seven miles long, and the reactor's way at the top of the bluff. So there was great comfort from the idea of this very long road to get there, and the people running around with guns and grenades.

But also it seemed a little bit like playing Cato to Inspector Clouseau, right? But then after Fukushima, we started asking different questions about vulnerability. Because in Fukushima, it was not only the wave that got them, but also where their power backup was located that got them. And so we started asking about, you know, how are you provisioned for power backup if the power goes out?

And they said, "Well, you know, we have some agreements, and we have some verbals with the army, and they'll support us, and, you know, we'll get backup fuel from them." And I was like, "OK, well, I'm a contracts professor. Do you have any contracts in place for backup power?" They're like, "Uh, no." So, you know, when the stuff hits the fan is not the time to negotiate a contract for backup power.

Tony Earley did work in the nuclear industry and now has negotiated contracts for backup

power. Because you also want to have people who are at least committed to prioritizing you. And that's also one of the lessons from Sandy. One of the greatest vulnerabilities in Sandy was the inability to pump gasoline and pump diesel. So, making sure that you also have access to backup power, whether it is from diesel, whether it is from the ability to physically turn on diesel tanks and have spigots...in a lot of rural areas they're already set up that way. Looking at storage, what we can do in terms of alternatives to help to reduce vulnerabilities. And also just recognize, you know, the different ways in which threats come.

When we talk about vulnerabilities and the human threats, it's not only bad guys, but also just the things that we do. So I was reading in this book about how there's one trick called the candy drop where bad guys will actually leave flash drives in the parking lot of defense companies, and some people actually pick them up and put them in their computers. OK? So don't do that, right? Just treat it like a piece of candy you found in the parking lot and don't eat it.

But then also there are these issues about malware. I shouldn't rag on my husband here, but last year my husband ended up in the doghouse because he was on the computer at home and he says he clicked on a little link about Katy Perry. He's a Katy Perry fan. And you know, lo and behold, there are these fake FBI warning with the ransom-ware and all that. So God bless the Geek Squad. And so he had to take a day off and pay the Geek Squad to come and clean out our computer.

So I was pretty upset for a day or two about this. But then, you know, I realized, how many times have you been looking at a website and then you see some ad about something that you searched for previously, and it's like, "Oh, I was looking

at those shoes.” But now you never know, right, what is actually infected with malware. So as we look at these types of vulnerabilities, and in terms of human vulnerabilities, part of it is the training, and training people about what to do. “OK, leave the disk in the parking lot that you found on the asphalt,” you know? “Don’t click on these things.”

But also, thinking about physical separation of certain systems. So, for example, when we talk about SCADA (supervisory control and data acquisition) systems and their vulnerability to hack, this can be super scary when you’re also talking about things like water systems and water purification systems. So I visited with one of our water companies that we regulate, that they are treating for perchlorate. It’s actually a vestige of the aerospace industry in Los Angeles. And perchlorate cannot be boiled away. So it’s very important to do perchlorate.

Actually, they had a little failure, like, two days before I came. So they had a bottled water alert, and just that morning things were back, and they were able to deliver water again. I actually felt sorry for them. It’s really bad day when a commissioner’s coming and you have a bottled water alert and you’re a water authority. But they are so concerned about hacking for that system, because if it fails, that’s what they have to do, is bottled water. So they have the water ready to go, the bottled water.

But that particular system is not connected to the Internet. Because what they’re doing is so incredibly mission-critical in terms of treating this water. So, you know, it’s sort of like, they call it the air gap, you know--the nuns put the balloon between the two dancing children, or teenagers. So this is really more of an air gap approach in terms of, how do we get to security?

So just a couple of closing thoughts. The Internet of things is already here, and distributed resources in generation are already here. They’re not going away. They’re just proliferating, as is the Internet of things. So the question is, really, how do we also proliferate awareness of cyber security threats, making sure that we have those vulnerability assessments and that we’re taking steps to do smart things? But also, you know, watching for our other flank and realizing that other things can get us that we didn’t expect.

And when we look at other threats, a lot of our biggest threats...for example in California, we just talked about yesterday the threat to our electric system from drought and from smoke, and heat can affect line loss, etc. Smoke can also interfere with the lines. Our San Onofre Nuclear Power Plant went down because of excess vibration inside the plant. And then, here, Metcalf was just a reminder of physical threats.

So the last thing that I’ll mention is that California is collaborating with industry to try to address these issues, and the California Public Utilities Commission has worked with industry and the legislature to authorize the California Energy Systems for the 21st Century, or CES21. So this is a collaboration between Lawrence Livermore Laboratories and our large investor owned utilities. And they’re looking at two different issues, one is cyber security threat analysis, and also looking at potential solution. And then the other is renewables integration.

And we have dedicated about \$35 million to this project over five years. They have put in their first proposal, and their first proposal is going to be machine-to-machine responses to cyber security threats. So they want to be able to look at automating the response to cyber security threats. I certainly agree you need great people to be able to do this, but also I think we already are seeing a lot of bots and lots of very

automated cyber security threats and we need responses that can work as fast.

And one of the things that Lawrence Livermore also can do (I encourage you all to think about working with the National Labs), is that they're saying when you have at your disposal supercomputers and the ability to do really massive analytics, that it drives you to ask different types of questions. So it's simply an analytical and a research tool to think about the solutions. And part of the solution here was also in terms of promoting coordination.

And this is an area, in terms of antitrust law, that had for a while been somewhat gray in terms of, how far could the industry go in coordination with each other without actually creating any antitrust problems in terms of collaboration? And the Justice Department and the Federal Trade Commission recently put out guidelines on cyber security coordination that actually encourages this as a pro-competitive activity, as long as it actually doesn't bleed over into sharing of information about prices and outputs.

And so one of the things that we did take out of CES was that originally there was a proposal that they would develop and market joint solutions and establish joint pricings. So that's the kind of things that starts to bleed over into antitrust land. But short of that, I think that this is a very productive collaboration. As I said, we just got in the first proposal, so we'll be considering that at the commission within the next few months. And so hopefully we will have some good working coming out of it from this collaboration and see how the machine-to-machine goes. So thank you very much, and leave those disks in the parking lot.

Speaker 4.

Good morning, thanks. So for those of you who are not familiar with PSEG, I put some of the facts and figures on this slide. What I didn't add here was that PSEG is Speaker 2's son's public utility. I should probably add that to the list. And we have a growing population of coyotes in New Jersey. We also have a lot of guns. I don't know how they compare. But because of the asset mix, and just being in this industry, PSEG faces a lot of risks. And you heard about some of those risks yesterday.

PSEG faces commodity fluctuation risk, and customers being dissatisfied with a whole host of things. And these three risks that I'm going to focus on today. Each of them is a little bit different, but they have similar characteristics in how we approach dealing with them and how we evaluate the threat and the likelihood of the threat. So I do think there's a common theme that can be seen in each of these kind of unique categories.

And we're reminded every day--or maybe not every day, but today in the newspaper, if you haven't seen it already, there's an article about a bomb that went off yesterday, I believe, in a generating station in Arizona. And I immediately checked with our security folks, and they had already been working with the FBI. But these threats are coming about every day, you know, whether it's a major storm or whether it's the Metcalf situation or whether it's some cyber security attack, which you don't hear about as much but certainly they are occurring regularly. We do hear from our local branch of the FBI about concerns on a constant basis and we work with them on that.

So how do we manage these risks and prioritize them and address them? Well, this is a framework that I copied from a joint DOE and homeland security paper that was issued for the energy industry. And our company uses it. I

think many of the energy companies use this framework. And you can see how each of the pieces is very logical, assessing the risk and understanding it. And it has a circular nature. But what's perhaps most important is to realize that we can't eliminate these risks. We can't have absolute reliability and we can't protect against all cyber attacks or physical attacks.

So it's a matter of understanding the risks and understanding that they come from many different sources. Obviously we know, perhaps most of us in the room, about the type of unpredictable weather that we can face. But we also have to think about our own contractors. At PSEG, we have about 2,000 active contractors on our site all the time, and understanding their background checks, and where they've been, and what they've done before--as well as suppliers and various vendors that bring things in. Even, you know, the Coca-Cola delivery truck that comes into your secure area to deliver to your vending machine, you have to understand all of those risks.

You have to also understand your risk tolerance. You know, some things you can tolerate being attacked, and you can deal with them, and understanding that is a better choice than spending the money to try to prevent it. But appreciating it, understanding your risk tolerance, understanding the likelihood of that risk, is really critical before you make the investments and apply the resources to try to mitigate the risk.

And one steady element, from PSEG's perspective is that building resiliency and redundancy into our electric grid really does help on all of these types of risks. It helps to mitigate and reduce the level of harm that we can face from severe weather or from cyber or physical security. As one of our executives at PSEG constantly says, "On the physical side, I

can't protect every single asset I have out there." And so, understanding that, you can isolate that and have some redundancy built in to address the problem, which is really critical.

So what can regulators do? State and federal regulators play a very important role in working with utilities and our industry on understanding these risks, understanding what the options are, and sharing information. And they have many security experts available to them that they can collaborate with. And I put down a couple of categories here where regulators really do play a critical role. Probably the most important one is information sharing, on a confidential basis.

And we've learned, I think, as an industry, that confidentiality is challenging. We have very curious newspaper writers, and learning how to deal with that...But for the most part, when I talk to my security folks at PSEG, they believe that the relationship with the government has been very helpful, very collaborative, extremely cooperative. We do have a common goal. And so overall it's been a very positive relationship.

And on the state regulatory side, as well as at the FERC, supporting investment where you have determined that investment will help mitigate the risk, and you've gone through that assessment that I had on the previous page. And most recently in New Jersey, some of you might have heard that we had our Energy Strong program approved. And our Energy Strong program was approved as a \$1.22 billion investment over three years in our distribution system to harden our system and to build in resiliency and redundancy to prepare for future storms.

So we're just getting started on those investments. It'll take about three years to get most of them in. A couple of them will get done sooner. Some may trickle on a little bit past the

three years. But that was, I think, a very good example of where we worked with the state and the stakeholders that were going to be impacted by this and came up with a solution that we all agreed on. It was not as big as what we had hoped. But we'll be back for more investment.

And at the legislative level, clearly there are many other aspects of information sharing: helping us work through the challenges of transporting equipment, whether it's a in a Superstorm Sandy type situation, or some other situation, bringing in army-type vehicles; national security-type measures to help us get gasoline to gas stations; and all that coordination. The federal government and Congress and the Pentagon play a very critical role.

So for PSEG, some of the specific things that we've done on the security side is that we have a very specific group of people that this is all they do. It's very important, when you have these types of critical assets and you are aware of the risk that you face, that you have people for whom this is their job. And those people have to have the right security clearance. We have several associates that have secret government access. It's very important, because otherwise you can't learn about the information that they're learning about. And we do have foreign governments often trying to access our system. And for being able to get access to those government conversations to learn about them and understand them and share information, it is really critical that you have those clearances.

We also participate in several key task forces. You can't participate in everything, so we've identified these through our internal experts, many of them former FBI agents themselves, and IT experts who focus on, for example, what's the latest attack that could happen on the cyber security side and evaluate whether we

should have honey pots, or things in our system--all these great little words they have in the cyber security world.

So those people participate in select task force. I think we're unique in the fact that we participate in three FBI joint terrorism tasks forces, because of our location in the Northeast. And we also participate in quite a few of the industry efforts to share information and understand what other companies are facing and share what our experiences are. And a lot of benchmarking, and lessons learned can be gained from that. We cannot install all of the mitigation measures that people identify and that the government comes up with, but we learn from those dialogues and committees which ones seem to make most sense for our unique assets. And we have been able to identify which of our assets would have the most harm if they were attacked, and really focus our attention on those.

So, in summary, in facing these risks, we try to be proactive. We try to be informed. We try to make sure that we have the right people thinking about this. As Speaker 2 said, it's not just what you know, but having people think about what we don't know and what we haven't thought about yet, and having an understanding of our risk tolerance, our investors', our regulators' risk tolerance. Understanding which of our assets are most likely to be attacked, trying to assess what remedies could protect against an attack, or at least slow down an attack, or make us aware of an attack sooner.

And as Speaker 3 said, we have many measures such as cameras and all these high-tech lighting equipment, Spot-Shotters, everywhere around the cities that we operate in. And we spend a considerable amount of money on those investments. We try to do it prudently and carefully and thoughtfully. And we recognize that we're not going to catch everything, but we

try to identify what we think is the highest risk and the biggest harm, and we constantly evaluate it, as the framework indicated earlier.

And a best practice, in our opinion, is where you look at all of these things holistically. And you can see, we have in here our Energy Strong program, various committees that we're part of, being part of benchmarking and analysis. And that's it. Thank you.

General discussion.

Question 1: Thank you. And thank you for the presentations. I wanted to ask a question which has always puzzled me when talking about this and related topics, and I warned Speaker 2 I was going to do this. If you think back, remember the Y2K problem, where the date was going to turn over and the software had a zero-day problem where we didn't have the right date representations?

And it dominated the news cycle for literally years in advance, and we spent an enormous amount of money on repairing the software. There was no doubt that we didn't catch it all. I mean, it is completely impossible to get it all. And then the day happened, and nothing happened. Right? And then it just disappeared from consciousness, this thing which had been all over this discussion.

And Speaker 2 and I have a colleague here, Matt Bunn, who is the world's expert on the loose nukes problem, particularly after the fall of the Soviet Union, and on weapons floating around and materials to make nuclear weapons. And he gives a seminar on a regular basis, and I go to it. And if you think Speaker 1 is scary, let me tell you, Matt Bunn will make you really worried. And then I always ask the same question at the end of the seminar, and I'm asking it now, which is, "Why hasn't it happened already?"

I mean, the way we hear about this, there are so many people, there are so many ways, there are so many things, there are nuclear weapons all over the place, there are cyber attack opportunities... And I just think there are one or two possibilities to explain why this hasn't happened already, but I'd like to hear what others say. One is, it's harder than you think, and that's kind of the Y2K story. It's kind of harder to create the science fiction movie outcome, and it doesn't really have that kind of impact.

Or maybe, there are some kind of defense mechanisms that we have, and some of these things that we don't know about, because they are classified, and I'm glad they're doing it and I hope they keep it a secret and I hope it keeps on working.

But why, if it's this serious, this dangerous, and this easy to do, why hasn't it happened already?

Speaker 2: I think it's always, from my perspective, a question. 9/11 hadn't happened until 9/11. That's one thing we should remember. Second, there have been lots of things which have happened, in terms of theft. I mean, enormous amounts of bank records, etc. I think that's a known fact. Right? And the communications infrastructure is so important, and in the Metcalf case, cables were cut, and we don't know exactly why.

So the point is, I think we have to balance this issue. And my own view simply is the following. Yes, some of it is slightly exaggerated, but there are, there was the Stuxnet issue. The Iranian centrifuges were disabled. So there is a real proof of a real thing being attacked, besides bank credit cards stolen. I mean, Target nearly lost its business. The CEO resigned. OK? So there are these examples here.

It's not the same as blowing up a power plant, but on the other end, you could certainly affect the electricity industry big-time by disrupting the communications infrastructure. I think the real thing which we need to do is to balance the risks with the costs. Like, you have to isolate the water system because you just cannot afford to have poisonous water. Electricity might be a slightly different situation.

And my advice simply is to always have a small group of people...first of all you need to have an emergency response system, depending on the scale of the response. And it did happen, phones didn't work, and there was a serious issue in this country. And we really need to have some farsighted people, a small group of people here who are always thinking ahead and aware of this threat. That's so important. That doesn't mean you spend billions of dollars. It can be relatively small.

This is quite important, so you actually are prepared. That's sort of my answer. Because the nuclear part is very different. In fact, it is much more difficult. There are issues of proliferation, of course. But, also, if somebody stole nuclear materials, there is the possibility, though you wouldn't hit all of the United States, that some significant small city could be affected, which we will not want. But I think there it's a very different situation. I don't know.

Speaker 3: So part of what I would add to that is that, while Y2K didn't turn out to be the huge problem it was thought to be, there were actually some isolated instances. My cousin actually did some Y2K consulting, and had a couple of his clients call him at two o'clock in the morning. These were smaller clients, you know, that didn't have the capability to do everything that was necessary to prepare. But what Y2K really did for our country, in retrospect, was

incentivize updating and replacement of a whole lot of communications and computer infrastructure.

So that was part of, I think, why it turned out to be not as big of a deal, because a lot of things were just replaced. We do see and we hear about things that are happening all the time, like denial of service attacks. Those are very real. There are a number of ways in which you have attacks, you know, worms are very, very real and happen all the time. And you know, these kinds of things, as they get inside the system, and as more and more of our systems are computer-operated as we are relying on SCADA systems, as we're relying on communications, again, you know the vulnerabilities, if you have a SCADA system that's connected to the Internet, that's extremely vulnerable.

So thinking about the architectures that you can use to help protect against that, I was reminiscing with another participant about the Diablo Canyon Nuclear Power Plant, and he was remembering during the height of the energy crisis one day getting a call that Diablo Canyon was closed because of kelp having swarmed the intake. And actually last year it was the jellyfish cousins that also hit the intake. And it was the second time the jellyfish cousins had hit the intake. So it sounds like a sci-fi movie.

So, you know, there are a variety of threats. But also, when you go inside some of these older power plants like Diablo Canyon, the control room of Diablo Canyon reminds me of, a scene in the original Star Trek where Spock and Kirk go back into some old military facility, you know, where the computer is as big as this room, you know, with all the things on tape. And that's what the Diablo Canyon control room reminded me of. There are a lot of old-fashioned dials still (they say that people can read dials faster than you read digitally), but it is very deliberately not

connected to the Internet in there. You know, they've got a lot of really old-fashioned controls that are isolated because they're trying to create an environment that has the air bubble where they could be hack-free. But we certainly do see other instances. There are reports of hacks into thermostats.

And when we talk about the Internet of things, and not just distributed generation but also other distributed computing, it may be that the greatest level of vulnerability are these things now being set with passwords and sufficient security so that...you know, you don't want to end up in the movie where your house traps you and attacks you, right? So there are a variety of ways in which I think that these are real issues, but where, again, we need the awareness of the evolving threats and the variety of natures as well as preparation and expertise.

Speaker 1: There have been penetrations. You can go on the DHS website and you can read about them. They have not affected the electric network. There are several that have affected the water networks. There are lots of small water networks. DHS has action teams. This goes to what Speaker 2 said. There are some very smart people who are out there ready to help and to put patches in place. But there have been penetrations.

As far as the electric network, you have to decide whether you believe or not that our systems are already penetrated. There are some people--again, this is public non-classified reading material--some people who believe they are penetrated. And what is keeping them safe is, effectively, mutually assured destruction, that is, government-to-government. But it's something that the national security people are taking seriously.

There are efforts to start distributing government technology. It's called Cyber Risk Information Sharing, CRISP (whatever the P stands for). It's going to be expanded this year to 20 utilities, maybe 50 by the year after. And it is automated.

But I think an answer to why it hasn't happened is that the people who really, really have the capabilities at this point don't have the intent. We are not at war. So it's what Speaker 2 said, it's the lone wolf, if you want to call it, the non-state actor who may not have the skills, no matter how high they may be, of the cyber army, whether it be ours or a state actor. But I think you have to take on faith that it's possible. And I guess, in my own mind, if we have a cyber command whose job it is in time of war to bring down other people's systems, I've got to believe that nations with equivalent capability have equivalent organizations. Am I being paranoid? You know, even paranoids have enemies, I guess.

Moderator: Well, let me just ask a quick follow-up. Are you being not paranoid enough? I mean, you said there's no state actor with an intent... I mean, Iran was attacked with Stuxnet. Why don't they clearly have an intent to retaliate?

Speaker 2: May I? First of all, they suspect Saudi Arabia was attacked significantly, Saudi Aramco, that completely brought down... And they suspect it was the Iranians. I don't know the answer. That's number one.

And I think with China, it is much more connected. They're not going to attack us militarily. But it really is going to be the threat of information. Right? And so I think the bigger threats here are, it's not a question of bringing the electricity system down, but really the communications part, which is also so central.

Also, not having an event like Y2K happen, partly because people did some of their own work... We could say, "Well, the TSA has now worked, there has been no attack in the US since 2001. So why don't we disband all the TSA?" And I'm no great friend of TSA, but you know, they might also be doing a good job here in the way they are doing this.

So there is a balance, of course, with the cost. So the fact that there are real cyber events is indisputable. Stuxnet was really a thing, but also lots of bank thefts. Man, that's really a serious issue, of course, in a different way. So the cyber threat is real. The question is, will it destroy the world? That is a different matter. But you could bring things down. You could bring the communications infrastructure down.

Speaker 4: And could I add something? I agree that there's real proof out there that we know this can be done. I mean, we see that when there's a financial gain to be had by hackers getting into your system, they do it all the time. The Target example is a good one. And it's happening regularly. So unlike Y2K, where it was a theory about what might happen, we see this happen. And I think, with reference to what Speaker 1 referenced about the intent, we don't know this for certain, but we do know that government entities are constantly pinging our system. We work with the FBI about that. Are they in there already? That's the part we just don't know. I don't know if the attack on Iran really qualifies an attack. It seemed to me more it was a monitoring, kind of testing. And maybe they're doing the same thing.

Moderator: Oh, I think they perceived it as an attack.

Speaker 4: They perceived it as an attack, just as Germany perceived some of our monitoring of their telecommunications. So you have a

combination of, we know it can be done, we know that even for telecommunications devices the technology exists right now for people to remotely turn on the speakers and listen to your conversations from your phone and watch you from the camera that you have in your room. You can buy software to do that for very little money in our local stores.

So you know it can be done, and it's just a matter of, do people have the intent to do real harm with it? So you have to monitor it. At PSEG we don't spend nearly as much money paying attention to that and watching it as we do on storm hardening and resiliency, because we know that there's not as much we can do on the cyber security, so it's much better to be aware and work collaboratively and understand it and try to get a handle on it. Spending millions and millions and billions of dollars to try to address it might just be throwing money, you know, as an individual company, in the garbage. So you have to work more collaboratively with law enforcement and national security.

Question 2: A sufficient number of people were asking about the incident at Nogales, and I thought I'd just give you like a 30-second overview of that, since there were enough people who were curious. And then I had a question as well.

Essentially a makeshift bomb was placed under a 50,000 diesel tank at the Valencia Generating Station, which is a peaking facility near Nogales. And it did not explode. But the FBI, the Bureau of Alcohol, Tobacco, and Firearms is investigating, along with our local law enforcement. And the spokesman for Unisource, which is a subsidiary of UNS Energy, and the parent company of Tucson Electric Power, he did note that 30,000 customers could have lost power, because there is a substation adjacent to where the tanker is located.

So there's a good story in the *Arizona Republic* today about it, which I'd be happy to email it to anyone who's interested, certainly of great concern to us on the commission, needless to say. And we do, in Arizona, have a program that was put in place in the year 2000, which was, I believe, instigated by the FBI and the Department of Homeland Security, called the Arizona Infragard Program. And it basically is an information sharing program from the feds to instruct utilities and others about threats and how to combat them.

And last September, I participated in a classified FBI briefing. And one of the comments they made, which was not confidential, was that we need to break down the silos between commissioners, utilities, and law enforcement. Part of the challenge, of course, is that so much of it is classified. And I wondered if you had any thoughts as to the best way we might go about doing that. I mean, we just discussed that in the broadest terms, but I would be curious to get your thoughts on how we can best collaborate, as it were. Thanks.

Speaker 1: Let me just give an example. Starting last December, there was a joint government-industry effort in ten US cities, I think it was ten US cities and three Canadian cities, for cyber, for physical security workshops where they had government, industry, law enforcement. It was aimed at education of both utility personnel and also of local law enforcement, to understand the kind of things that need to be done.

You know, some of the simplest things, like making sure law enforcement has the address, knows how to get in, knows where they have to go. It may not be so hard within the city of Chicago, but in a rural area a facility might not even have an address. So there are efforts being undertaken at the federal level to do this.

As far as the other thing, and I think both Speaker 4 and I may have referred to it, going back to 1996 and an executive order by President Clinton, there is a certain apparatus for each of the critical infrastructure sectors in the United States. And under that, one of those apparatuses, is called the Electric Subsector (because electricity is a subsector of energy) Coordinating Council.

That council has been reformed in the last year, and it is made up of 20 CEO-level people. And when I say CEO level, I mean these CEOs of IOUs, Munis, Coops, the industry associations including NEI, and NERC has one representative there. And they meet periodically at the deputy secretary level, with the deputy secretary of energy, the deputy secretary of homeland security, the FBI, someone from the White House, to go over the various issues, the various threats, and action items.

They also include secure briefings. There's been an effort to get all the CEOs briefed. Now, understand, that doesn't include the states yet. This has only been going on, like, for a year. Before that, NERC was it, and it wasn't expanded enough. And there have been actions out of this. One of the biggest actions is, we all now have, and we've exchanged, emergency response plans. A lot of these have been informed by Hurricane Sandy. They've been improved upon. And we're talking.

Let me just give one example that you don't necessarily think about. If there's a cyber incident that knocks out power somewhere, what's the most important thing the utility wants to do? Restore power. What are the most important things the FBI wants to do? They want to close off the crime scene and collect evidence. Those two actions are not compatible. But we are talking. We are talking. And that's an

example. Not the only one, but the long and short, it has to be a government-industry collaborative. The government and the regulators have capabilities we do not, and we have capabilities they do not. We have to work together to get it done right.

Question 3: Thank you. So, you know, we're very excited about the collaborative that we have authorized with Lawrence Livermore Laboratories and the investor owned utilities. We're looking forward to what's going to come out of that in terms of their assessments and solutions. And hopefully it's a model that we can look at with our sister states. NARUC, led by our immediate past president, Phil Jones, really made cyber security a priority. That was the number one theme of his administration.

Of course we have a critical infrastructure committee. You know, I was looking this morning at some of the reports that NARUC has done, including questions that regulators can ask about cyber security where we also look at risks and costs and various sorts of issues--the human factor as well as collaborating with the federal government and some of the federal forms. As you mention, there are sectors, not just the electricity sector, but the communications sector...

And I think one of our challenges is to really get us talking across sectors. The communications sector, in part because many parts of the communications industry are no longer subject to rate of return regulation, has really resisted some of the reliability requirements that are imposed on the electricity industry. But, yet, it can become part of the Achilles heel for the electricity industry, as well as a way into vulnerabilities. So looking at how we can promote that collaboration, I think, is going to be very important to the future.

Question 4: I have a deceptively simple question, and it regards cyber security. In this space, what is success going to look like? How would we know when we've achieved it? In other words, I don't think it's realistic to think that utilities are going to prevent sophisticated state actors from hacking their control systems. All the information sharing in the world's probably not going to achieve it.

So is success keeping the floor relatively high? Preventing non-state actors and capabilities from shifting? Is it ensuring that we have resilient systems that, when they fail, they fail gracefully? Yesterday the comment was made that reliability probably isn't priceless. There's a point at which you're spending money to achieve a very marginal gain in reliability. I'm sure the case is the same with security. So, again, in this case, what is success going to look like?

Speaker 4: No, I think the highest level of success would be that, you know, five years from now we're still having this conversation about the potential threat, and we've been able to defend against any major problems. But I would say the next tier of success would be that we identify the cyber attacks as soon as we can, because I think one of the biggest concerns is that they're sitting there and they're just waiting for the right moment.

And then that we have plans and procedures in place to bring the system back as quickly as possible, whether that's through having additional redundancy in the system and being able to isolate it, or having a successful program to work with our neighboring utilities who are not impacted, and with federal and local agencies, to get the system back. But I think it really has to include the restoration efforts, identification and restoration working the way

we planned, and the way that we handle all the drills and preparation for it.

Speaker 3: I think that's a great question. You know, with cyber security and the variety of attacks that we do see--whether from denial of service, worms, attempts at infiltration--the reality is that the need to be vigilant about that, I think, is going to be persistent. So this is like flossing your teeth, where you have to keep at it every day.

And so looking at the current new threat levels, trying to morph to be able to deal with that, seeing what we can do through automation, really identifying the vulnerabilities, training people to minimize the human aspect of the vulnerabilities, staving off the big attacks, and also creating resiliency and redundancy. What are your plans for recovery? That could involve a combination of demand response and alternative sources. One of the fastest growing companies in America is Generac, the backup generator company. So a lot of people are prepared at a business level and even an individual level for the backup, and I think we have to design systems that are also prepared for resiliency as well.

Question 5: There's only a finite amount of money one can spend on security. And how do we establish the priorities between, you know, natural events, physical security, and cyber security? And so how do you establish the priorities?

Speaker 2: Well, I think partly, you use your experience in judging what the threats are. I mean, obviously with storms, etc., you have a whole history, and you begin to start doing that. You can always argue, should we put all the cables in the ground? We don't. Right? And the same thing with climate. But I think in the cyber area, the way I would do the priorities involving

threats, I set a small group there. But the communications part is so important that I would put some resources there in terms of my priorities, because in fact you cannot afford to lose your communications infrastructure, and you may have to work with the phone company or whatever, to do that. So I think that's the arguments one has to go through in terms of the cost-benefit analysis here.

Speaker 1: I agree with everything Speaker 2 said. The problem is, the policymakers who sit in that building with the dome in Washington tend to attack these issues one at a time (no pun on the "attack"). And so one day it's electromagnetic pulse, "You must do something!" The next day it's getting worked up over, "You haven't done enough about physical security," as if we have not been paying attention. So you need a standard.

In 2007, there was something called the Aurora Alert. OK? This is not classified, it's out there. You can read about it on the NERC site. One of the national labs did an experiment and they found that if you opened and closed a circuit breaker very rapidly, you could destroy a small generator. You can even see this on CNN. DHS somehow let that tape out. And all of a sudden, there was this huge panic that, "You've got to fix the Aurora problem." And there were hearings in Congress, and, you know, NERC got lambasted, and we got brought up there, "What are you doing about aurora?" While the engineers believed this was a discreet, limited issue, it got into the political arena and just went nutty. We need an intelligent conversation of the federal, state, Canadian (because don't forget about the Canadians, we are connected to them), and industry about the priorities. FERC has ordered us to develop standards on solar storms. Was that wise? Those people are paid to make that decision. I, you know, am not going to say whether it was right or wrong. That's their job.

But that's going to be money that's going to be spent, and that's money that's not going to be spent on cyber or physical security. Or it's more money that's going to be spent. I think we have to have that conversation and, you know, try to get Congress not to go nutty with the issue of the day. But we need the conversation. And maybe we just have to have it state by state as to where we're going to put that money.

Moderator: Let me follow up. Because you reference Congress, and let me speak as a state regulator and just ask you a question. I mean, really, Congress is secondary to this, in a way. I mean, certainly it is involved at the highest level. But most of what is going to be invested in cyber security--hardening substations, hardening distribution systems--is going to come before state regulators who are going to be asked to approve it, and it's going to come out of the pockets of consumers.

So first of all the "conversation" will take place in a lot of regulatory proceedings at state level. And I always remember that great quote from Alfred Kahn about how a utility would build a pyramid if they could put it in the rate base. If a regulator tells the utility, "Any amount of money that you put into hardening the distribution system, hardening cyber security, hardening substations, we will give you immediate cost recovery plus a very generous return," isn't there a danger of, frankly, getting too much of it? Because that money is coming out of the rest of the economy.

And of course this obviously is the hard thing about rate of return regulation. You're trying to duplicate the results of a competitive market when you don't have one. So, you know, you're trying your best to get the best result you can get, knowing it's imperfect. Isn't there a danger that waving the flag of, you know, securitizing

everything, and I don't mean in a financial sense, but in a, you know, "Harden this, harden this, harden this," that we're frankly going to get overinvestment, and that is not a good thing?

Speaker 1: Well, that's why I raised Congress. Because, even though they don't do rate cases, if you look at some of the drivers that I just discussed, the order promulgated by FERC was driven by the Senate. It was driven by the Senate as a response a year later to Metcalf. We were going along doing the work in what we thought was a prudent, reasonable manner. We know what the critical substations are. We really do. We know the kind of measures that need to be taken.

Speaker 3 mentioned ideas like using opaque fencing, you know, so then you can't see what you're shooting at, things like that. But Congress just got spun up. They got spun up on Aurora. That's where I see the risk that you're talking about. And so somebody passes a rule, and now you have to comply with the rule. Granted, you're absolutely right, it's going to come before the state commission as to whether what you did was prudent. And now you, as a regulator, I think, have to balance the risks versus the costs.

Speaker 2: Could I add something? I've never heard utilities ask for that. And I know this is mostly a room of state regulators, but you know, utilities really don't want to build pyramids in their system to include them in rate base. We care about, you know, customers moving out of the state to our next-door neighbor, and losing customers, and we're constantly under criticism about the level of our rates. I think there is a point, and I don't think any of us really know where it is, where electric rates or gas rates become too high for customers.

So we're always evaluating, what is the right investment? And what we did recently in this Energy Strong proceeding, I think, is a good model. We went into the regulator and we said, "All right, we have these specific things that we think would be very helpful to do. We don't need to do them to meet our statutory duty. But we think these make sense. They're expensive. We need to work together to decide if you agree we should spend the money on these things." And we had AARP in there, and the Sierra Club, and the large energy users. And at the end of the day, it was a lot of torture in between with everyone.

But at the end of the day, we agreed on a set of investments that everyone said made sense based upon the risk of future events that no one really could predict when they were going to occur or how they were going to occur. But we said, "This level of protection makes sense." So I think that's a good model. We make evaluations every day about where to put our money. And in my presentation I pointed out, we spent about \$500 million on physical and cyber security in the last few years. We've spent billions on infrastructure.

So we are making those choices. But as Speaker 1 said, we don't have all the right investments to make to protect against cyber security. So it's more information-sharing, collaboration, understanding the risk. And those are different types of investments or expenses than building redundancy into the system, or taking a substation and raising it up above the flood level that's changed because of whatever reason you might perceive. So I think we are faced with those risks, and utilities are not always just trying to increase their rate base.

Speaker 2: I want to take on this question at a different level; namely, there are some shorter-term issues that obviously require certain kinds

of tradeoffs. I really want us to think of the long term. That's what I was taught. And the long term means a small amount of investment in a cooperative way with industry and government. That's how the old telephone system was built resiliently.

And if you look at examples, the Gas Research Institute actually funded shale drilling, along with DOE a long time ago. So some investment needs to be made for exactly that. And the one example that I saw today was what California is trying to do, working with Lawrence Livermore Lab, to do some of those projects, etc. It is not a huge investment, but well worth the money, with a lot of leverage. So start thinking a little bit long term. That's the nature of this technology.

Speaker 3: I think we're doing that. At least the utilities like PSEG and Exelon. We've worked with FERC, and everyone agrees, us and FERC, about what are the facilities that are most at risk. And we know what those are, and we're working with Homeland Security and the labs. Because the answers are not that obvious. We need to spend the time and the resources to figure that out.

Speaker 2: And develop the knowledge base, right? If I call on the research fellow, Ryan Ellis, he can tell you why many of the companies are actually having bounty hunters, and paying them for it, etc. Microsoft, they don't want to just throw money around, but they have good reasons for doing that. So we need those kinds of case studies, etc., and that knowledge base.

Speaker 4: And it's not just on the cyber side. We just had the Navy Seals come in and test our security measures. A lot of utility companies are doing that in cooperation with the government, and doing drills and tests like that to see where the vulnerabilities are. And they need to.

Question 6: So, following up on this conversation, I just want to get to one more level of concreteness. What do each of you think we should be spending to protect ourselves? And what do you think the bill impacts of that would be? What, in California, is the bill impact of the Energy Strong proceeding?

Speaker 3: I can do the easy part first. Energy Strong came at a very opportune time, because we had a lot of other charges rolling out of the bills, including QF charges from PURPA; those contracts were finally coming to an end. And we had some tax law changes. So there was no bill impact of Energy Strong. There was a rate impact, obviously, but the total bill to the customer, when you took all those other things out, was neutral.

Questioner: Well, that's net. But if you hadn't added something, how much would the bill have gone down?

Speaker 3: It was less than 5% of the total bill. And, of course, you can slice and dice that--what percentage of distribution charge versus the total bill? But that's all public. I'm happy to share it with you.

Speaker 1: I don't know that I have numbers, but I think if you look at the threats versus consequences, we ought to continue to put money into resiliency and restoration for severe weather events. If we don't get an irrational Congressional response to the NERC standard on physical security, I don't believe that the physical security bill is going to be that large, because you're not talking about 50,000 substations. You're talking in the hundreds in the country.

I think we do have to put more into cyber security. I believe that those people who know this a lot better than I do believe that that really

is the major gross threat to the network. We are doing so. We are hiring people, computer experts, security experts. The unknowns are these emotional issues, the ones I put up there. There is a bill in Congress that keeps going around called the Shield Act that directs FERC to issue a rule for utilities to protect against high-altitude electromagnetic pulses.

Can that be done? Yes. Speaker 2 is a physicist, and he knows better than I do, we're going to put things in Faraday cages and we're going to do all of that. The military's done that since the 50s. They've hardened discreet elements. But all of those have costs. And I can't tell you what those costs are, and truthfully I can't, even in my own mind, say, should we be doing this? Because the consequence of some of these things truly is so terrible, that maybe we should. It's a national security matter, not an electric system matter. You know, in my own mind, that's the kind of thing that should be funded by taxes, not by the rate-payers, if you're going to do it. Some of these are hard issues.

Speaker 3: So, as was mentioned by my colleague, we look at these issues in rate cases, and then sometimes through other proceedings outside of rate cases, like the Lawrence Livermore Lab project with the CES21. So, at \$35 million over five years, we have 38 million people in the state of California, and PUC regulation touches about 75% of them. So, doing the quick math in my head, it's around \$1.50 per rate payer over five years. So, you know, that's actually not a lot of money, because we're peanut-buttering it over a very large group of people.

And then when you look at the potential consequences, the potential consequences are high. So I think that this is a good investment. We are seeing, in every general rate case, there is a cyber security component. In fact, if a utility

came to us with no money budgeted for cyber security, I think we would look askance at it and ask them whether or not they're being sufficiently vigilant. And the reality is that, you know, physical security has long been a need, and is something that we have to look at. I think we should look at it smartly, right, things like what was mentioned--opaque fences, lighting...

Part of the issue with Metcalf was, the cameras were facing in. There weren't enough out-facing cameras, you know. Also, doing different things with the lighting might have helped. The pictures that were taken of the people who did the shooting are very shadowy because of where the lighting was placed. So, again, this gets back to the issue of thinking differently about the threat and where the threat is coming from. But when we talk about physical security, you know, again, the Boston bombing shows us that physical security is an issue out here in the world.

I had the opportunity to actually begin working on electricity issues in 2001 during the blackouts, and had worked for the Federal Communications Commission before then. So I was working for California's business transportation and housing agency when 9/11 hit. And all four of those planes were actually headed for California, where is where they were supposed to go. So we had a very heightened security alert.

And, again, it's public information that over the years there have been people arrested in Spain and other places who had really interesting nuts and bolts photos of the Bay Bridge, you know, and these were not tourist photos. So, you know, hardening our infrastructure, really identifying critical infrastructure, is something that the federal government has been engaged in for some time, as has state government.

After 9/11, we did a threat assessment 6hw6 identified, you know, the electric grid system as one of our critical infrastructures. We have, for a very long time, been thinking about what are some of the big threats, like some of our bridges, and what we can do to harden them. But just looking at our interconnected society, we know that cyber security is a financial issue; it's an economic issue; it's a security issue. So, the reality is, this is something that we're going to need to embed in the work going forward.

Question 7: First, a brief observation that may or may not have any value as an analogy. But as we think about the lions and tigers and bears, the beasts that we fear, which we're trying to protect ourselves against, it is perhaps worth reminding ourselves that, by many orders of magnitude, the creature that kills more humans than any others is the mosquito. I don't know if that means anything for what we're trying to do here, but as we contemplate the costs and where we dedicate our resources, you know, we don't necessarily want to make the mistake of protecting against lions and tigers and bears when we're all going to get killed by mosquitoes.

But my question is an entirely different area. Yesterday we had a lot of discussion about distributed generation. And one of the questions we've been struggling over internally, as we try and prepare for a future and to facilitate distributed generation, is that there's an increasing demand for detailed and updated maps of our grid that provide information to potential developers about where it would be good and where it would not be good to develop their distributed generation, and what the cost implications to them are of different geographic locations on the grid.

It appears that it's possible that that's sort of anathema to providing appropriate security for the grid, to provide that public information out

there with those detailed maps. But maybe it's really not an appropriate basis for a security concern. I was wondering what the panel thought. Should we be trying to resist the demand for that detailed information about our grid for the very legitimate purposes of siting distributed generation, or is that really not an area to worry about?

Speaker 2: This is a real issue. I would probably develop some quality metrics here to know who I'm giving the information to. That's a simplistic answer, but that's the way I would see it. Because I think in fact there is now a real need to think of it in those terms and really develop the public policy issues connected with that, so that, you know, there may be a kind of "seal of approval," which says, "These guys are fine, and therefore do this." At least, that's what I think.

Speaker 1: I think the cat's been out of the bag for a long time. FERC requires the filing of transmission maps. There is a procedure that anyone can use to request those maps. And if your name is not Osama Bin Laden, you will get those maps. And putting joking aside, how they then get controlled after the fact...we've been in a dispute with the PJM market monitor about getting specific GPS coordinates of all substations. We feel that there's a problem in having that all in one place. But the other side of the book is, he can just go to one of these services and get the same thing, or close to the same thing. Close. These are visible pieces of equipment, I don't know how you can stop it.

A lot of this distributed equipment, it will be connected to the Internet. And for all the expertise that the utilities have--and we do, you know. I mean, we hire some very qualified people--if you've got a system connected to the Internet, I doubt your Norton or McAfee is going to keep out even an unsophisticated attacker. Now, granted, you have to attack

10,000 targets at once. But, with computers, that's easy.

And so I think what many of us have been trying to say is, we need resiliency; we need restoration plans. We need restoration abilities. Because, you know, I doubt that anybody sitting there in New Jersey and Pennsylvania remembered the 1938 hurricane on Long Island. Well, maybe some people did, but very few people did. In Fukushima, there are mementos in that area going back hundreds of years saying, "The water came up this high." Not in people's memory. That's another issue. So I think that cat is out of the bag, and we have to deal with it.

Speaker 2: In the cyber security arena, there is a great deal of debate right now about having a centralized cyber command versus a very distributed one. We talked to the computer science people; many of them believe in the highly distributed approach. So I think this debate is going to be resolved. My own guess is, it's going to be some kind of hybrid, and we're going to have to develop this in case studies. This is an extremely important area to study, the relationship between central versus distributed systems here. So stay tuned. I think it's important.

Speaker 3: California already does have maps that are available, for example of high-wind areas. The federal government has also identified certain high-solar areas. We've also classified certain areas as high-solar areas in the desert. We've identified good areas to interconnect to the grid. So, you know, you can imagine what a malicious person can do with that. But it's also important to balance that against, you know, our goals for renewables integration.

And, actually, because California is already well on its way to meeting the 33% renewable goal

by 2020 (we've already hit about 20%), we're thinking that the EPA's new proposals are not going to be a big stretch for us at all. So, you know, it's a question of balancing those benefits.

And I was thinking last night that this whole area of cyber security also runs up against the whole ethos of openness versus being closed, right? And, you know, it's interesting, because the Obama Administration has really pushed open data. President Obama has signed directives about opening public data and making it machine-readable.

I spoke a couple of weeks ago at the White House Energy Data-palooza, talking about what we can do in terms of assessments with this data and big data analysis. And you can look at some very interesting stuff, like for example some of the Volt/VAR fluctuations that are happening. And there are some very interesting solutions now to deal with that, because voltage regulation used to be something done centrally. And some of the new solutions are looking at how you can do it in a more distributed fashion.

As we deal with distributed resources, we have to change how we deal with these things. This means thinking about, OK, what data is really smart to share? Do we need exact GPS coordinates? No. Do the police need to know where the Metcalf substation is? Yes. And so, you know, it's how do you create those sorts of confidence levels for sharing that kind of information.

But, again, with this whole debate about distributed versus centralized generation, I think distributed is already here. And I completely agree with what Speaker 1 said. The weak point is not going to be the utility that can hire the Seals to do various drills with them, but it's going to be somebody hacking the thermometer that then tries to use that as an entry point to

engage in what we haven't talked about here, which is cyber espionage.

You know, there's a lot of debate about what's going on from China, and of course there are a number of Chinese people who are now on the FBI's top ten most wanted list because of their participation in cyber attacks. But a lot of the alleged motivation there is also about industrial espionage, and essentially stealing intellectual property. So I think that's a whole other component that we have to be vigilant about, both in terms of the legal issues as well as the cyber issues.

Questioner: I did kind of expect that that was the answer, but it is worth noting that every year when I take my NERC training and I'm told everything I have to do to protect the critical infrastructure information from the public, that we're simultaneously sending out these maps with all that information, or at least enough of that information in it.

Question 8: So, Speaker 1, we are a member of the Electric Subsector Coordinating Council (ESCC). Last week, I attended a meeting at DHS chaired by Deputy Secretary Poneman and Undersecretary Spalding. You had 30 CEOs in the room, led by Tom Fanning of Southern. You had APPA, NREC...I was sitting next to Cheryl LaFleur and Joe McClelland of FERC. You had NERC with Gerry Cauley. You have all the players in the room that are necessary to take high-level action to direct their staffs and organizations to take this threat seriously.

Just to give you a brief overview, we talked about CRISP, the technology program that Speaker 1 said is being deployed with certain utilities. This has some problems, or some challenges, on the privacy side. But it gives instantaneous wide-area situational awareness of what the attackers, the bad guys are doing.

And I know, Speaker 3, that you've been very active on the water energy nexus. So this council is going to be reaching out...as Speaker 1 said, there are 16 critical subsectors in the country: natural gas, nuclear, finance...you know, just go down the list. These are all coordinated by federal government agencies. The electricity subsector, as most of you know, is the only one that has mandatory standards on it from a federal government agency. Finance doesn't have it. The information services subsector doesn't have it. Natural gas doesn't have it. EPA regulates the water sector. There are no mandatory standards for cyber and physical security imposed on water utilities.

So that may give you a little comfort as well, but there is an active effort to reach out, especially on the transportation side. We passed a resolution in NARUC last summer in Denver. As we saw with Hurricane Sandy, there are these big issues with transportation trying to get the crews across toll ways, state highways, interstate highways, to where the issues are. So we passed a resolution encouraging us to reach out to our state governments and highways departments, national guards. So there's going to be a lot of effort, I think, from the ESCC to do cross-sector collaboration, recognizing the interdependencies of the system.

And on the topic of incident response planning, we still have a lot of work to do to work with governors, national guards, and the states to get this right. But a lot of good work is being done.

I visited the Electricity Sector Information Sharing and Analysis Center (ES-ISAC) that's part of NERC, located in Washington D.C. And they have a lot of proprietary things that they're doing to identify problems on the system. Some of it is proprietary, but I can tell you one thing. The Heartbleed incident--remember Heartbleed

came out? Those guys told me that they knew about Heartbleed, and all the foot soldiers in the utilities knew about the Heartbleed incident two days before the CEOs did. Then it was elevated up to the CEO level.

So Deputy Secretary Poneman, with direction from the White House, I think, said, "Get the utilities on the phone." So Poneman got the CEOs on the phone. So it was elevated up to the CEOs. It was done within four hours. The only reason I raise those points is that with ES-ISAC, we have a new coordinating mechanism for electricity. That doesn't make me sleep well at night, totally. The threat is very dynamic, evolving all the time, and the skill level to buy the malware on the Internet is getting less and less. So we all have a lot of work to do.

After doing this for about a year, the challenges seem to be vendors and procurement. So what are the utilities doing on supply chain management? As we saw with Target and others, it's not Target's CIO--I mean, he probably was not doing his job well, but the contractor for the point of sale machine, that's where the vulnerability was. And, lord knows, the utilities are buying lots of software and hardware for SCADA systems, IT systems.

So that's kind of a challenge, I think, a long-term challenge that we've got to deal with. Small versus big. Speaker 3, you and I have talked about this. The small water utilities or the small rural coops in my state, they don't have the resources or the cyber experts or the money to spend on cyber security. But if we define cyber as a common good, because we're so interconnected that if one part of the system goes down the whole system goes down, then how do we deal with the issue of small utilities?

And then the other issue is metrics. And this is not really a question, but for reliability, of

course, what are the metrics that we're going to use on both resiliency and cyber? We don't have good metrics now. So one of the challenges that state commissions are going to have is measuring success.

So how do we measure it when PSEG comes to ask for \$3 billion for security? Likely some questions like, "Well, what is your metric? How do you measure on a cost-benefit analysis how good this investment is?" And that's just something we're going to do. So I don't have an easy answer to that. NARUC is being asked by DHS, DOE, all these federal agencies to deal with these issues. There's no easy answer. But I wonder if the panelists have any comments on any of those issues?

Speaker 4: So, very good questions. And let me start with the last one first, because this was actually a big issue in our Energy Strong case, cost-benefit analysis and metrics. How do you measure when the next storm, like Superstorm Sandy, is going to come? And we hired Brattle, and they helped us put together a cost-benefit analysis, which was very different than the cost-benefit analysis that had been seen in regular utility proceedings before. It was a break-even analysis.

And it said, we don't know when the next storm is going to come. We don't know how many storms. We know the life of these investments are approximately 40 years. It depends on the type of investment. So we know that once we put it in, it's going to be here for 40 years, we're going to be paying for it for about 40 years. And we know that it's highly likely we're going to have some major event during that time period. So they took the cost and said, how many of these events would it take for this to pay for itself?

And I think that was a very smart way of looking at these types of events, and it was actually, I understand, taken from or based upon some national security analysis that's done on how the federal government spends money on defense measures. And it worked. People finally got comfortable with it. We did also agree to some special metrics on monitoring the success of these investments. And I think that's also transferrable to some of these cyber and physical security events.

We agreed there wouldn't be any penalties for not meeting the metrics. They were really intended to measure whether or not these investments made sense, before we make the next round. So we will be preparing, through the life of these investments, specific information that measures how these areas where we've made these changes, added resiliency, added redundancy, how they compare to where we haven't done that. And it will be information that the regulator has.

On the first point on vendor procurement, that's been one of our top issues over the last couple of years. And just this past week, we had our executive group sign a new corporate policy that requires all of our vendors...and we have a lot of vendors. When you start thinking about, like, who are your vendors? It's everyone who does the cleaning, the mail, the potato chip machines that are in the building...We have all of them, depending on what they're accessing and what buildings they get access to, go through a specific type of background check. It costs money to do that, but we decided that it's absolutely necessary. And we have had situations where we've been concerned about learning after the fact that some of our vendors had some associations that we weren't very comfortable with.

So it's a new policy. I think it was the right thing to do. We sat down with all of our different business leaders, everyone from the nuclear plant leaders to the IT specialists to the security people, and came up with something that we all agreed would make sense and tried to minimize the intrusion into the business, and that tried to keep costs low. And we'll see how it works.

Speaker 1: Let me go to the third part of your question, the metrics. In theory, it's easy. You take the impact of an event times the probability, and you compare that to the cost. It's a lot easier to do with conventional weather, because you've got a pretty good data base. When you're dealing with very low-frequency events, things that you don't have a good data base for, or that may go back hundreds of years, it is a lot harder to do that. You, in effect, have to take it on faith that an event will occur. That's the cyber security issue. We don't know the probability. We don't know the full impact.

So what the policymakers have said is, "Assume a penetration, and assume the ability to do something." To some extent maybe that's the way the NRC says, "Assume a pipe break, assume a loss of coolant." Then you have to try to look at the expenditures and say, you know, are they in line with what you believe will accomplish that goal? The problem is, as I mentioned, this Aurora thing just diverted attention from the bigger picture. So I think you won't have the precision that you would normally get in a rate case.

You have to look for reasonableness. When you get even further out--the solar storm where a big one may occur every 250 years, you know, again, what is the impact? What are the prudent things to do? My belief is that a lot of these threats we're talking about we can solve by some sort of process, whether it's national, whether it's multi-state, of more spare

equipment. Because you won't stop everything. That gets into the vendor and the procurement issue.

Question 9: Speaker 3, you've mentioned twice the possibility of hacking into smart thermostats. How concerned should we be about hacking into smart meters, thermostats, other smart devices?

Speaker 3: I think that's a great question. And this kind of gets to the earlier question about small versus big, so that it's not just a question of small IOUs, like small water systems, where we might be able to also still regulate them, there's information sharing through the water associations, but also small products that are unregulated. I mean, nobody's saying to Nest, "You have to have this level of security," and there's not really a standard about that issue.

So with regard to the smart meters, you know, there is some security on our end, and they are supposed to be designed to be not easily hackable. But, I mean, again, if you guys are looking at, within your states, new installations, I think that that's certainly a question that is worth asking. And certainly the people who are smart meter opponents are very concerned about that. You know, the ability to even just access the data to know when you're home can result in burglaries, let alone, you know, what they could do to devices.

But also when you think about that for an industrial customer and the types of processes that you could initiate, you know, that could really be a problem. But this is a real issue with the Internet of Things, and I'm actually organizing the Internet of Things Panel in Dallas, and so this is something that we're going to be talking about. As we see the proliferation of the Internet of Things, I think it is a vulnerability that needs to be examined. And it's

something, again, that the industry really needs to embrace.

One of the issues is that, this is not about trying to foist regulation onto people. It's also about just understanding what our vulnerabilities are and how we can create security and safety as things become more interdependent with each other. And whether you're looking at it from an industrial perspective or a home perspective, there might be some reasons to keep certain legacy things that are not so vulnerable to hacking. And that, I think, we might also see in the future--you know, cyber security for appliances in the Internet of Things, being something that's actually featured.

And this is an area I think that would really be apt for standards. And on the question about supply chain management, I think this is really important, and I'm glad to hear about your work on vendors. Remember, Edward Snowden was a contractor.

In this book I was reading last night on cyber security and cyber warfare, you know, they were talking about how the janitor's computer can be vulnerable. OK, now I was thinking, "Wow, the janitor has a computer?" Many times the janitor isn't assigned a computer and a desk or an office. But whether you're the janitor or the Coca-Cola delivery person, you're walking in with your own computer now, in terms of a cell phone, and what that can do. So vendor policies are something that we really do have to be aware of.

Question 10: My major concern has been, over the last two years, extreme weather and cyber terrorism as well as physical terrorism, with the large systems that we have with central station generation and that large transmission grid.

And the military, Department of Defense, is using a lot of micro-grids for security reasons. What lessons have we learned and can we learn from what the Defense Department is doing with their grid systems? And on the issue of distributed cyber terrorism, is it easier or harder to do that?

So I had thought, from what I'd been reading, that it actually makes sense to have distributed systems because they can't take it all down, you can go offline, etc.

Speaker 2: I think that's a very important debate. There are many computer science people who actually believe the distributive systems will eventually, just like the physical security, be much better. And there's now recently a paper which I haven't read carefully which has been written, and I can probably give you a reference for it, exactly trying to debate this point about the central versus distributed. And my instinct says that distributed has certain security aspects which are good, but eventually it'll be a hybrid answer. And this is the debate which I think will be resolved in the coming year, because this is being raised extensively.

Question 11: Looking ahead, if you were given the opportunity to have a dedicated team of smart post-docs or graduate students who were already funded, and there were no strings attached, what question would you love to see explored that could really matter right now in your decision-making?

Speaker 1: I would take that chart from the Chertoff Group, and I'd use that as a starting point. Those are the threats. And I'd also have them look at the threats that we weren't smart enough to identify--the unknown unknowns. And I'd say, "Look at them, what would you do, how would you prioritize them? Think out of the box. And how do you deal with all of them?" It

has to be an all-threat analysis. It can't be today physical, tomorrow cyber, the next day hurricanes. And that's where I think the industry is trying to go, an all-threat analysis.

Speaker 4: I agree with Speaker 1. The only thing I would add is, I would ask that they analyze the likelihood of the event occurring, and what we could possibly do about it.

Question 12: So far today we've talked a lot about what IOUs are doing and not so much about what the ISOs and RTOs may be doing. During this past winter, when gas prices were high, there were all these applications made to raise the offer caps in certain of the eastern RTOs. And I don't even know if this is true, but I heard that New York ISO decided to apply to do it as an out-of-market payment rather than a clearing price, because its software couldn't accommodate paying the generators over a thousand dollars, which struck me as something that was not very sophisticated. And in the context of all of this, I'm thinking we need something very sophisticated. So my question is, do we think that the RTOs and the ISOs are doing enough?

Speaker 1: As far as cyber security, the ISOs and RTOs are subject to the NERC standards in the same way that the IOUs are. As a matter of fact, since they operate control centers, they have even higher level requirements. The control centers don't operate as substations or anything. So as far as those kind of threats, I'm not worried about them. They're with us. We're all together.

Speaker 3: So CAISO is very focused on resiliency and reliability. Those are key issues that they look at and monitor. But I think this also gets to, you know, what events are we thinking about? You know, with California we lost the San Onofre Nuclear Power Plant

because of some problems, it turned out, with the generator that were causing excess vibration.

There was no CAISO planning horizon or CPUC or CEC planning horizon that assumed that both units of San Onofre would be unavailable for any extended period of time, or that both units of Diablo Canyon, our two nuclear power plants, would be unavailable for any extended period of time. And in one minute, we lost San Onofre, and then after a year and a half, Edison decided to close it because it just wasn't economical to go through the process with the NRC.

And so, again, this is almost a failure of imagination, you know, in terms of thinking about what our real threat was. That wasn't a cyber threat, that was actually a manufacturing defect. So part of it is also looking at, you know, what are your planning assumptions? And we ended up back there again this year with the drought that we have in California. This year we have, so far, a zero-percent allocation to our water users from the federal water project in California. A zero percent allocation from the California water project, which is incredibly important.

We have certain areas that heretofore had gotten 100%, 95%, 75% of their water from the California water project. In the Silicon Valley, 55%. Thankfully, many of those areas do have water stored. But, again, there was no planning scenario that assumed a zero percent allocation. So you know, this gets to the black swan scenarios where you have a really high dependency on one or two critical things, such that you have to think about what happens when that's out, and plan for that, and then fold that into your planning and assumptions.