HARVARD Kennedy School
JOHN F. KENNEDY SCHOOL OF GOVERNMENT

HARVARD ELECTRICITY POLICY GROUP

HARVARD ELECTRICITY POLICY GROUP
SEVENTY-FOURTH PLENARY SESSION

Shutters on the Beach
Santa Monica, California
THURSDAY AND FRIDAY, FEBRUARY 27-28, 2014

Rapporteur's Summary*

Session One.
Energy and Capacity Markets: Carts and Horses in Parallel Universes

Turmoil in energy markets prompts action to redesign real-time pricing models for energy, scarcity, intermittency and uncertainty. The implications for revenue adequacy and investment in the right kind of capacity for generation and demand response yield a parallel universe of attempts to design better forward capacity markets. The parallel policy discussions struggle to deal with problems better treated if the universes were better connected. What are the major design defects in day-ahead and real-time energy markets that give rise to the call for capacity markets? How can energy market redesign alter the need for and structure of capacity markets? What are the purposes that the capacity market would serve with a better energy market design? How can demand bidding, scarcity pricing, and better models of the value of reliability address the underlying problems, and simplify or improve the specification of what is needed for capacity markets? There is no alternative to having an energy market, and the principle of keeping the cart before the horse dictates the priority for fixing the energy markets. But most of the pressure is to fix old or found new capacity markets. Are there alternatives to capacity markets, and how can we think about the value that capacity markets bring to the electricity system?

Moderator: This session is focused on this discussion of energy and capacity markets, and those of you who know these presenters know they have very divergent views on the question of energy and capacity markets. The turmoil in energy markets prompts action to redesign real-time pricing models for energy, scarcity, intermittency and uncertainty. The question here is, what are the major design defects in the day ahead and real time energy markets that give rise to the call for capacity markets?

PHONE 617-496-6760 **FAX** 617-495-1635
EMAIL *HEPG@ksg.harvard.edu*
79 John F. Kennedy Street, Box 84
Cambridge, Massachusetts 02138
www.hks.harvard.edu/hepg

Speaker 1.

Good morning everybody. I'm very excited to be here and have this interesting topic that obviously cuts across many different areas.
Here's a pie chart showing the regional fuel mix for New England. And while the gas number is roughly a third in terms of capacity, in terms of actual generation, that number is inching well over 50% and has been for the last couple of years, and has certainly driven, in New England some of the situations that have led us to examine issues associated with the energy and the capacity markets.

I think there are three major elements that have driven a number of the uncertainties that have forced us in many respects to take a deeper look into these markets: natural gas, that has driven lower overall prices (even despite what we've seen this winter, and this winter has actually also highlighted some of the volatility that can become inherent with further use of natural gas); integration of the variable/distributed resources (and I'd also include demand responses as one of those); and then out-of-market revenues--the big ticket item that has gotten a lot of press are MOPR issues, but I actually want to focus a little bit on some of the more traditional out-of-market issues, which are out-of-merit dispatch, uplift issues, and the impacts that those types of actions, albeit for potentially very real reliability reasons, have in dampening and undercutting the price signals that are occurring in the market.

So, as always, it's all about the money. And that's what this comes down to. So as we look at this, to take a little bit of that step back, let's make sure that that pie of money is the right size. Let's make sure it's getting allocated to the right people and that it's being sliced up in the right fashion.

So in terms of the size of the pie, what is it that we're looking for in terms of overall revenue adequacy for the marketplace? I think when we talk about capacity markets, it's often termed as the "missing money," which is right. And yet, when we look at the energy capacity and ancillary services markets, what are the opportunities across those markets to get the revenues? Let's make sure they're coming in at the right levels, and again, that the prices being sent through those markets are the ones to actually provide those services, avoiding the out-of-market payments.

Similarly, I think there needs to be a clear definition around who can participate and under what terms. How do you get the right folks in there so that you're ensuring that the folks that have the opportunity to capture that revenue are the ones that are going to providing those services, or at least have the capability of doing so, and certainly can deliver on it?

And then finally, slicing it up, making sure that you're putting the right products in the energy, in the capacity, and the ancillary services markets, potentially creating new products…

But before we even get to any of that, make sure that overall the different pieces actually fit together, so that when you hand out the different pieces of the pie, if you took them back, you could actually reconstruct the pie, and it wouldn't have a cubist painting look to it. And as part of that, I do think it's important to take a holistic view across the markets.

FERC, to their credit, has done deep examinations, most recently of the capacity markets across the regions. I think one of the key takeaways from the technical conference that was held back in September is that you can't look at the capacity markets independently. You have to look at them with the energy markets and with the other markets and make sure that they are coordinated. And that is even more challenging in markets across the country, and especially in New England, where they are designed one at a time, and historically have been designed through settlements, and there is concern about whether or not there is somebody who is actually holding the pen and making sure that the pieces come together. So coordinating between the markets and making sure that they actually fit together is critical.

Price signals are another key component--making sure that the out-of-market payments are not undercutting the true price signals that are necessary. From my perspective, the key to that is making sure that you're actually defining, within the products, what you're looking for, making sure that all of that is captured through the markets and not, "Well, we've got this one definition for what we're looking for from the capacity side, or the energy side, but you know, there's something that's fallen through the cracks, and for that, we're just going to have to dispatch folks out of merit or create these uplift payments." All of that needs to be included.

And the last item here is mitigation, which from my perspective is the element that isn't talked about nearly enough. What we see is the potential for a market monitor or other entity t replace the business judgment of an actual resource operator. That, from my perspective, is not the role of mitigation. Mitigation is there to help prevent and deal with market power and manipulation. Instead, what we've started to see is this practice of, "Well, gee, I know you think it's going to be that number on the fuel market, but really, it should be X." And that is replacing the business judgment of folks who are putting their capital at risk and entering into the marketplace, and it's something that I think is extraordinarily difficult to regulate, but it's something that needs to be addressed.

So all together it's creating an explosive situation. But I'm an optimist. It doesn't have to be combustible. And what I would offer here is a modest proposal, rather than an overall scheme on the design. I think we can take a targeted approach, and to me right now, the low hanging fruit here is, let's get the product definitions right in each of these different markets. What is it that we're actually trying to buy within the different markets? What are the attributes associated with the service? Let's make sure that the elements within the broad definition are actually capturing the needs of both consumers and operators.

And then, finally, what are the obligations of the resources that bid in to provide those services? We need to articulate those up front, so we're not in situations like the one we ran into recently in New England, where we had to have a big fight down at FERC over the performance obligations for a product that was sold three years ago, because there was lack of clarity around those obligations. Let's identify those up front, and make sure that all of those different attributes, all those different prices are reflected in the actual prices that are clearing in the marketplace that will then incent the appropriate behavior and investment to get us there. It's a modest start, but I think it's something attainable in the short to medium term, while at the same time we're all dealing with the grand market designs that we're all in the middle of.

And with that, I would be remiss if I did not at least pay some lip service to the fact that we're going through quite an interesting discussion in New England on the capacity market. We've got an ISO New England proposal. We've got a NEPOOL (New England Power Pool) alternative. So if you want to know more about that, I'd be happy to talk to you at the bar and give you my cracked, clouded crystal ball on how all of this is going to shake out, but obviously that's a big deal. That's the elephant in the room that we're dealing with in New England. So with that, again, I appreciate the opportunity to be here, and look forward to the discussion afterwards.

Speaker 2.

Thank you. I'm going to try to go through the beginning parts of my presentation relatively quickly. For most of you, this is just reminding you of the context. But the focus is on scarcity pricing, and here I’m thinking about, in particular, real-time and day-ahead kind of frameworks, and questions of resource adequacy.

Speaker 1 has already mentioned the familiar “missing money” problem. This is a graphic that we used before to represent the short-run electricity market. When you get into tight situations at the maximum capacity…in the original design, we thought demand bidding and price responsive demand was going to solve this problem for us, and we didn’t worry about it too much. But we didn’t get responsive demand for a variety of reasons that we’ve talked about before. It’s not the only thing that causes depression of prices. There’s a whole series of actions that cause depression of prices. But it’s critical, and we recognize that pricing in real time markets has not been adequate in the past to support the kinds of projections of what people think about what we need in terms of investment, although it has had the effect of improving investment in all these different kinds of markets.

The response to that, generally speaking, is to recognize this as a real problem, but the response has often, until recently, not really focused on the problem of really improving scarcity pricing to deal with all the issues of investment incentives, demand response, renewable energy, transmission, and so on. The typical response--not everywhere, but often--is to come to the conclusion that fixing the scarcity pricing problem is too hard, and therefore we need something else, and the something else is a capacity market. And then we get into all the details of capacity markets, and then I can just incorporate by reference everything Speaker 1 said about the issues that come up there.

So my efforts, as you know, have been to focus on trying to fix this scarcity pricing problem, on the grounds that it would help, broadly speaking, and would remove some, if not all, of the problems associate with these markets and providing adequate incentives in operating terms, and for investments.

And the conceptual idea, illustrative, that we’ve talked about before, is to focus on operating reserves. Operating reserves were originally, in the schemes of these things, thought of as sort of fixed requirements. We knew that wasn’t correct, but it was good enough, and if you had demand participation, it wouldn’t matter very much, and everything would work out just fine. But if you don’t have demand participation, one way to approach this problem is to recognize that operating reserves actually don’t have fixed requirements. If you are at some minimum contingency level, say 3%, and if you could buy a little bit more operating reserves, it would be worth something, and as you bought more and more, it would be worth incrementally less, so you get the standard downward-sloping demand curve.

But here I’m talking about, of course, not demand curves for capacity markets that are three years ahead. I’m talking about operating reserves, where they’re for the next hour, or 15 minutes, or whatever the timeframe is that we’re building into that model. And if we had that kind of Operating Reserve Demand Curve story for energy and reserves, then we would get a mechanism that would in fact produce scarcity pricing. When the system was slack, there wouldn’t be much difference in prices. But when you got into the significant capacity utilization, you wouldn’t be driven down to the offer curves or the variable costs as people are estimating them, because the demand for operating reserves would set the price and set the scarcity price.

And this is an idea which has been around now for a few years and adopted in various ways in different RTOs, which I’ve listed here. But the problem with the existing implementations is that they don’t do a very good job of explaining the rationale behind them or connecting them to first principles, so that we can think about what we want this Operating Reserve Demand Curve to look like and how it connects to more fundamental ideas.

And a sketch of some of those fundamental ideas (I won't read everything, but you can read about them if you wish, and it's in the handout) includes connecting to the value of lost load and other emergency actions. So when you're curtailing load, or you're doing things which are essentially out of merit, or you're taking some kind of special action in an emergency, you should have a connection to that, which reflects the opportunity cost of doing that. Another fundamental is including some representation of uncertainty, because the inherent characteristic of these operating reserves is to deal with an uncertain future. Also, integrating the minimum contingency reserve requirements, which are there as a constraint to prevent cascading failures in the system, and so on.

So there's a list of things that we would think about, and the first part of that story is this probability and the value of lost load. At any given level of reserves, you will have some probability that in the next hour net load will go up or down. And if it goes down, well, then you don't have a problem, and if it goes up, you could have a problem. And if you go below the minimum level of reserves, which in this picture is zero, then you would get into the situation where you were either curtailing or taking advantage of non-market opportunities. But the curve itself, which defines the marginal value, trails off as the loss of load probability declines.

So it has a lot of nice properties. You could connect it to the value of lost load. This is a standard calculation we're all familiar with, and we usually talk about it in the context of forward capacity markets and long-term reliability tests. But the same principle and idea applies an hour ahead, but it's very different an hour ahead, because basically you know a lot more, so you're forecasting a lot less. You know where you are, what plants are available, and all those other kinds of things. So it's a lot simpler to do and have reliable calculations.

The connection with minimum contingency requirements so that you don't have cascading failures is this--it's just that there's a lower bound threshold, which is not zero. It's something positive. In this picture it's set at something under 2000 megawatts, and this is what in Texas they call "X" in the conversation about the Operating Reserve Demand Curve. And this is the idea that once you get below this level, you're going to have to do some kind of non-market intervention, which, for shorthand, we're going to talk about as load shedding, and then you have to value that somehow. In the simplest story, that would be to value that at the value of lost load, which I've assumed here is $10,000 per MWh, and then you calculate the loss of load probability for the rest of the curve, which tails across. And I was a little surprised when we first did this, but obviously after you think about it, when you're at that minimum contingency level, there's a big jump step up, because that's a deterministic requirement as opposed to a probabilistic story, and with the probabilistic story, there's some chance things get better, not worse. And so that's why it doesn't go to 100%, so it connects at a lower level, a little over $6,000 in this example.

I'm going to slow down a little bit now, just for those of you… [LAUGHTER] This is all the stuff we've talked about before, so this was on the pop quiz. But you can take that same idea, and you can then extend it to deal with nested models. So you have spinning reserves and non-spinning reserves, and they interact with each other in a particular way, and you can describe what that is, and that's all doable, and that's actually, for example, in the Texas design, that idea comes along.

And now I'm going just explain quickly what this next picture is about. The simplified idea that's embedded in putting those two nested things together, and the simple approximation here that we're using, is that the next hour is divided into two intervals. In the first interval, only the spinning reserve is available, because it's the only thing that's synchronized and spinning, and then after, in the second interval, both kinds of reserves could be available. So the non-spin is not available in the first period, only in the second period. And if you take that little two step approximation over the period, and the net change in load model, and connect it to the loss of load probability, you get a result which is described in the equation on the bottom of the slide, which is that the price of responsive or spinning reserve is a function of both the loss of load probability at the level of those reserves, and then the price of non-spin, and there's an additive relationship between them, and that's going to be important for what I'm going to say in a few minutes.

You don't have to parse this equation. It's just implementing what's in this picture. The important part about it is that it's additive. So the price of spinning reserve is an increment above the price of non-spin, and that's important for what I'm going to say in a few moments. This has all been investigated at length.

My favorite paper that I've ever been involved in …I'm now starting to use it in all my presentations, because the coauthors are William W. Hogan of Harvard University and the ERCOT staff. [LAUGHTER] We had a long conversation about listing everybody's names, and this was the vote….This paper gets into issues of scarcity pricing and resource adequacy, that kind of Operating Reserve Demand Curve is in the process of being implemented in Texas, where the work is going forward. It would improve many things in scarcity pricing dealing with resource adequacy.

But the point, which I have made many times and repeat here, is that posing a choice between capacity markets and better scarcity pricing is a false dichotomy. Better scarcity pricing is a good idea no matter what, and it also makes the capacity markets less important, but it may not eliminate the need. It may not solve the problem of resource adequacy. Whether or not we have a resource adequacy problem depends on the planning standard of what we're trying to accomplish. We're going to hear a lot more about that, so I'm not going to say very much more about that, other than to say, asking this question is really important: "What are we trying to accomplish? And what is the standard? And how do we think about that?" And we'll hear more about that from others here this morning.

And the justification for the planning standard would depend on a more nuanced argument for market failure that goes well beyond suppressed scarcity prices. So if we solve the economic scarcity pricing problem with Operating Reserve Demand Curves and a few other things to fix anomalies in the models, which is not trivial, but not that hard, the kind of things Speaker 1 has listed off for you, you could still end up with an argument that says, "That's not enough." It might be enough. But you could make an argument that it's not enough. But we ought to figure out why and what exactly is the reason that we think it's not enough, and I suggested some examples here of things that might be appropriate, but I'm sure we'll have a chance to talk about that later.

And then if you decide that it's not enough (now I'm really going to slow down here) we have, broadly speaking, at least two paths that we can go down if we think the reliability requirement based on a simple economic equilibrium may not be enough. And one way is capacity forward markets, and it creates all of the issues that you heard about and you're going to hear more about. But one of the things you notice is the problem that Speaker 1 talked about in these capacity markets, in that we spend a lot of time trying to figure out complicated rules so we can provide incentives for performance in real time for the capacity that we have contracted for ahead, and the rules are all complicated and trying to undo one or the other, and they're not internally consistent, but they're all guided by, in the end, trying to make the penalties look like scarcity prices, or higher scarcity prices, or something like that, in real time.

And so one approach to this problem is to just go do that directly, and not go through the capacity market story, and that's the second possible path. Which is to say, if we're still worried about resource adequacy, it is not necessary to have a forward capacity market. We can still have changes in the spot market in order to deal with our conservative assumptions about reliability, if we could articulate what those are. One approach to this that you're familiar with and we've discussed is high or no offer caps in spot markets. So, Alberta is a good example. And if you're following what's going on in Alberta, you know about that discussion as well, but, basically, the shorthand description is that in Alberta, the solution to the missing money problem is, "Exercise market power." So that's the policy, and people can exercise market power, and that's a way to get prices up, and then you get more money. I think that's a policy which is, shall we say, difficult, if not impossible, to transport across the border.

But there's another way to approach that problem which is being discussed in various places, and that is higher scarcity prices. In other words, take the basic first principles analysis that I described with the Operating Reserve Demand Curve, and then tweak it. But know that you're tweaking it. So now you come along, and you say, "This is what we think is our best estimate of all the parameters. Here's what first principles would tell us. Now we're going to take one or more assumptions that are embedded in that, and make a conservative judgment about what we want to apply for that component, and then apply that as a way of providing incentives in real time and day-ahead in order to address this resource adequacy, reliability issue if we think we have one." And I'm not prejudging whether or not we have one, but if we do have one, then we have this problem.

And if you look at the Operating Reserve Demand Curve in the stylized version that I've been talking about here, an augmented version of that has basically three parameters that you could think about and have a conversation about, and all three have been suggested in various combinations by various people. And the first parameter is the value of lost load. So, this is a fuzzy number. I use $10,000/MWh as the round number. In the proposals in Texas, they've been talking about $9,000. You could argue for higher numbers. And so on. So it's not as though there's a rigid empirical test that tells you what the right number is.

But the problem with tweaking that number a lot in order to get more money into scarcity pricing is that it can create a fundamental inconsistency with what you actually do in real time operations. So if you're actually curtailing people, and you're charging them twice the value of lost load for the remaining load that's not curtailed, you're going to have a problem. So this is not exactly the most efficacious way to try to improve scarcity pricing--it will raise the prices paid in this Operating Reserve Demand Curve, but it's going to create these collateral operational problems.

I think the same thing is true with this "X" value. This is the minimum contingency level. And remember, it's supposed to be a proxy, not just for load shedding, but any kind of out-of-market events, and then pricing that--and again, it's the same thing. You could make that number higher, and then you'll have higher scarcity prices, but then you'll also get into the situation where you may not actually be taking any non-market actions, but the prices are going up to the value of lost load, because you've set this number conservatively, and now you're going to have all kinds of inconsistencies and perverse incentives created.

The third parameter is the loss of load probability. And I think that that's the right way to think about this problem, for two reasons. First, because it doesn't require you to do something that conflicts with what you're doing operationally, and second, because it is a vehicle for having a conversation about how conservative we want to be in setting our reliability judgment about what's missing from the model, and what we want to include by making it a conservative judgment about the loss of load probability.

So it's a different way of thinking about the problem. It's not one day in ten years, or whatever. It just says, "I'm going to assume that the probability of a short term interruption here is higher than the empirical data that I've used to estimate it, and I'm going to give myself a margin of safety," and then it's a judgment call, in part, about what the margin of safety might be. I have no idea at the moment the answer to that question, although I have some ideas about how we could talk about it.

But just to illustrate this idea with the numbers that came out of the Texas analysis, with $9,000 as the value of lost load, and $2,000 as X, the blue line on this graph is the stylized version of this Operating Reserve Demand Curve. I haven't done the split of spinning and non-spinning here, but you can see the idea. And then the other two graphs are superimposed--just suppose I change the estimated loss of load probability by one standard deviation. So I have an empirical estimate, and I just shift it by one standard deviation, and you get the red dotted line in the middle. And if you shift it two standard deviations, you get the green line at the top. And just by inspection, you can tell that there's a lot of money here. OK? So this is not a trivial issue here. And relatively small changes, comparatively speaking, given the uncertainty about what these probabilities are, could have a material effect, and it has all of the advantages that we know about. It provides the incentives at the right time. It raises the prices for demand response. Performance incentives are natural. You don't have to create them artificially. And it would have all kinds of very attractive features, and it's an alternative to a forward capacity market. I suppose you could do both. But I do think of this as now trying to incorporate our concern that resource adequacy isn't completely accounted for by the blue line, and we want something more. And this is a way to get more, but have it consistent with all the operating characteristics of the market.

The reason I went through that equation before is that if you actually implement this idea, my recommendation (not just from me, I've discussed with other people), is that you focus on doing this for the non-spin and not the spin. OK? Now, why is that? The non-spin gets to the problem you're worried about, which is just availability of generation. It's not that it has to be spinning. And if you apply this change in the loss of load probability to both the spin and the non-spin, the way the equations work is, it will change the gap between the two, so now you provide a much stronger incentive for people to run the plant and have it spinning, which incurs real economic costs. That's going to be expensive, and it's not solving the problem you want to solve. Whereas, if you focus on just the non-spin--remember it was just additive--what it does is, it just raises the non-spin, that also raises the spin, but it doesn't change the differentials, so it doesn't change the incentive to actually make the plants spin, and so you get the right economic mix between the two of them. And the conservative assumption is then applied to how you price reserves that are available. And I get asked lots of other questions about this problem, and this is the slide that has all the answers. [LAUGHTER] Thank you.

Question: What did you say? [LAUGHTER]

Speaker 3.

My talk is going to focus on a topic that Speaker 2 mentioned but went over very quickly, and that is price responsive demand.

First of all, I'd like to review today's capacity markets and how we got there. Then I'm going to suggest an approach or direction to move in to improve the markets that we have today, and in the end, show why this might be a much better idea. And it was a topic that was discussed early in the design and sort of left by the wayside.

Today's capacity markets are basically needed for two reasons. One is, there's not enough price responsive demand in the energy markets. And because the energy markets have price suppression, it has created the "Shankar missing money problem." The capacity markets create what I would call weak call options in the energy markets, but as we have seen over the last several years, they require a lot of administrative interventions in these markets and are highly contentious because there was probably too much money at stake. Some of the administrative interventions include the fact that the capacity markets are designed for the summer peak and not, necessarily, for the off peaks. There's a debate about what the marginal unit is, what the cost of entry of the marginal unit is, and, as we've already seen, what one in ten actually means, what a forced outage is, forecasting demand, market power mitigation rules, choice of zones, RMR status, going forward cost, and a question about exactly what is comparability.

The capacity markets also require the ISO to forecast future demand, retirements, future transmission, and profits in the energy market. The forecasts are inherently wrong--it's not the ISO's problem. All forecasts are inherently wrong. And the capacity markets put most of the risks of being wrong on load, which creates a principle-agent problem, because the ISO always wants more reserves, and not the optimal number.

We have a CONE (cost of new entry) debate, which is just a big generic cost of service debate. Anybody who's been around this industry long enough knows what a cost of service debate is. And it's essentially a jobs program for cost of service consultants. [LAUGHTER]

The current DR programs are a weak substitute for either "iron in the ground" or price responsive demand bids in the energy market, and we have seen this over the last several months. We get too much or too little. We get it too late. We get it in the wrong place, and we get it at the wrong time. And there are measurement problems in figuring out exactly what we have got. And so my feeling is, the DR programs need to evolve. And if we continue on the path that we're on, you can envision essentially a Rube Goldberg ATM for subsidizing technologies, and not a capacity market, and in some sense we're moving in that direction.

So what about the redesign? How can we change direction? And essentially I just listed market design principles here, the first of which is, you want to maximize benefits to society from the markets. You get that when suppliers bid their marginal costs and when demand bids its marginal value. You want to make sure the settlements are non-confiscatory, that is to say, don't take somebody's property, and incent efficient behavior. If you're going to do equity, you should probably focus it on need. There's also a parsimony principle, which I'm not really sure how it holds, but I used Einstein's quote, "as simple as possible but not simpler." And there's using bilateral markets to equilibrate risk.

So the first thing, and what I believe is the major problem, and something we haven't focused on enough, is price responsive demand in the energy markets. And that is essentially a very simple concept. It's a concept that demand bids into the energy markets, just like the generators do. But we've seen for the past several months, and maybe the past several years, that we need to focus on a better bidding program, that is to say, what's the marginal value of demand? What's the fixed cost of a call to a demand resource? What's the lead time? What's the minimum duration time? And what are the ramp rates? And you can get the demand participating in all these markets, plus the ancillary service markets, and in some sense, I believe that's the goal that we want to head towards. And if you have price responsive demand, you can always make the market reliable, because you can simple curtail demand based on its demand curve.

So we have the energy market enhancements. We get more price responsive demand participation. We get rid of the arbitrary caps on the bids and market clearing, and as a result, occasionally the prices could get very high, and in that sense I think we need stronger mitigation. I mean, the worst thing in the world, in my opinion, is to find yourself in these scarcity positions, and then to uncover the fact that you have generators exercising market power, which is going to create a huge backlash. And you need good shortage pricing, also known as scarcity pricing.

The results, and this essentially depends on both the shortage pricing, and I think more importantly from time to time that the supply curve and the demand curve actually meet, and they will meet at numbers around the, occasionally at the numbers close to where Speaker 2 said, six or eight or $10,000. But the good news is that you don't have to go through all those difficult equations that Speaker 2 put up on his slide. The demand response is actually going to tell you how to set the price. But you need the scarcity pricing to essentially incent the demand to bid into the market.

Now, one of the results here is, you're probably going to get load factor improvements and demand shifting its peak demand into off peak periods and things of that nature, and just straight up conservation, so it's not clear at all whether or not the energy prices overall are going to be higher.

Monitoring mitigation and manipulation becomes more important, as I said, because the prices get higher. I would argue that we can get rid of the market share test, the pivotal supplier test, the conduct and impact test, because they take up a lot of time that you can use for better optimizing the system, and focus on marginal opportunity costs and marginal opportunity value. And to that, it goes to one of Speaker 1's points, and that is to say, we really don't fully understand what the marginal opportunity costs of natural gas are, because if you buy your gas a day ahead, it may cost you $10, and if you have to buy it on the hour, for example, if you're scheduled to be a reserve in the New England market and have to buy it on the hour, it may be $140. But we have not had a robust discussion as to exactly what those numbers are and how you should deal with them in terms of the marginal cost curves.

The capacity market redesign--well, first of all, price-responsive demand is exempt from the day-ahead market, because price-responsive demand does not need a reserves commitment. You make the market reliable by essentially curtailing price-responsive demand. If you want to, you can add firm fuel requirements and firm transport requirements and all kinds of that stuff to the capacity market redesign. But the capacity market may still have a residual value. It may basically keep retirements from being premature, and it may actually incent construction when needed.

Transition isn't going to happen quickly. A lot of these capacity markets are already committed four and five years out, so it's going to take some time. We're not really sure how much demand response we're going to get into the market. I would even go so far as to have an auction to pay people to actually bid into the market. In theory, the auction should clear at zero, but we may need some kind of an incentive to get these people to actually bid into the market.

Capacity market prices and revenues would decrease, because you put more money into the energy markets. And with less money in those markets, they become much less contentious. The generators are going to make more money in the energy markets. They're going to have a stronger incentive to be available when the system is really under stress. And if they're not available, we don't have to have a big debate about what they should be paid or what they shouldn't be paid. They're simply not going to make any money if they're not there when the prices are high, and we won't have a whole lot of debate about penalties and things of that nature.

For demand, price responsive demand doesn't have to pay for capacity. It doesn't need capacity. It can get revenues in the ancillary service markets, and it has a much stronger incentive to conserve because the prices are going be higher, and a lot of the measurement problems we have now with demand response go away. There is a role for hedging. Arguably it's more of a bilateral market than it is a general hedging market, because people have different risk profiles about what they want to hedge and how much they want to hedge. And the states can hedge on behalf of retail customers if they think it's necessary.

Now, if you want to do equity, my feeling is, find a way to find the poor and subsidize them. And if you want good conservation, you price the externalities. And that's it. Thank you.

Question: My question is about the bid mitigation marginal opportunity cost and marginal opportunity value, is that only for generators, or is that also for demand side bids? And then if it's demand side, I just wondered how you calculate the marginal opportunity costs.

Speaker 3: Well, the marginal opportunity costs are for the generators, the marginal opportunity values are for demand. There's good news and bad news here. Demand is usually at least in order of magnitude smaller than the generators that you worry about, so I'm not sure how much of a problem that it. But it's certainly something that should be under discussion. And I put opportunity costs in there, because if you say marginal costs, some people will say marginal opportunity costs. When I say marginal costs, I mean marginal opportunity costs. But for example, say we're having a max gen emergency, and you have to run a generator beyond its normal operation, a lot of the ISOs have numbers in there for marginal costs that are probably way too low. And we haven't had a good discussion about what are the potential real opportunity costs of running a generator hard.

Question: When you're talking about how the states can hedge, what are you talking about, like a New Jersey, the BGS (basic generation service)?

Speaker 3: Basically, that's a hedge. And it may become much more important, because you're hedging against the potential for much higher prices, maybe overall lower average prices, but when you get into some of the situations that we saw this winter, when all of a sudden we realized that that $1,000 bid cap and price cap that was never going to be triggered actually was, and what resulted… hedging becomes more important.

Question: Do you have any other examples? Because I don't want to start PJM with this.

Speaker 3: No.

Question: You talked about exempting price responsive demand from the capacity market. How would you ensure the availability of price responsive demand in the relevant timeframe?

Speaker 3: Well, they have to put in equipment. I mean, if they're going to be exempted from the capacity market, they have to bid into the market, and they have to respond to price signals. I mean, we depend on compliance with those rules, and the generators generally do that. So I don't know why we couldn't get that kind of response from the demand.

Question: Is it enough to have a smart meter and be enrolled in a certain retail tariff? Or do you have something sort of more onerous in mind?

Speaker 3: Well, if you're a belts and suspenders guy, you might want to have a switch you can operate remotely. But I think, as a general rule, once the demand commits to do that, they'll do it. I mean, if that's a problem, then we have a bigger problem than I thought. And they are facing much higher prices. So it's not like it's just, "You're obligated to do this." It's that they're going to pay a very high price if they don't cut their demand.

Question: One thing we think about in terms of demand response is this sort of discrepancy between load buying at a retail price, which has a certain rate structure to it, and how that may be very different from what load would get paid as a resource in the energy market. Are you assuming that away, or does that complicate your story?

Speaker 3: It complicates it. I don't have an easy answer for programs that sort of flip the incentives, and we've seen plenty of programs where, when you had one type of rate design, and you changed a lot of things around, that rate design didn't make sense anymore. So you have to have faith that the states will do the right thing. Obviously, the states could probably turn back a lot of things. The hope is that you're going to get most of this response, especially at the lower price levels, from industrial customers and commercial customers who have more at stake and have more expertise.

Question: But optimally you would want the demand that's responding to be buying energy at the same price that it's selling reduction at?

Speaker 3: That's my hope.

Question: What is the FERC's stated rationale for continuing to require what you referenced--the traditional market share, pivotal supplier, HHI (Hirschmann-Herfandahl Index) type mitigation requirements for market participants in an RTO, when the Commission says, at the same time, "But if you fail those tests, we'll ignore them anyway," and you're going to rely upon the MMU (Market Monitoring Unit) mitigation of the RTO itself?

Speaker 3: Well, it's a jobs program for anti-trust consultants.

Question: On slide 14, maybe I'm misinterpreting what you said here, but you're only referring to demand response that actually bids into the ISO.

Speaker 3: ISO energy markets.

Question: Yes. And actually, in some markets, well, in all markets, you're ignoring the fact that there's going to be a lot of demand response that's passive. You know, small customers that simply respond to price. The ISO doesn't even know they're there. And this is an important element, and in fact I was going to bring this up with Speaker 2 during his discussion, because this accentuates the importance of operating reserve pricing, because that operating reserve pricing curve sets the price that these small customers respond to.

Speaker 3: Yes, the reason why I prefer a big chunk of price responsive demand is because both the day-ahead and real-time algorithms are look-ahead. I mean, the day-ahead looks 24 hours ahead, and the real-time market usually has a look-ahead that's somewhere in the range of four hours. And so you want to give those algorithms the opportunity to schedule demand response that is actually bidding into the market. I mean, by no means do I think that this is an easy task, but it's a debate we haven't had. I mean, eventually you want to get the ISO to learn what it sees in terms of the demand response that you talked about, the one that isn't bidding into the market, and it's going to have to forecast that. But when you're doing the four hour look-aheads and things like that, I think that the operators would prefer to have a bunch of levers they can pull, and especially since some of this demand response is going to take time. You certainly don't want it on a two hour time, but certainly getting it down to 30 minutes or things of that nature, so that you can manage the system better…Obviously we, I mean, the operators, make mistakes all the time. They start up units when they really don't need them. Because they're conservative, they will probably call demand response that they don't need occasionally also, because they're still going to be conservative.

Comment: Yeah, I know that well.

Speaker 3: Oh, one other thing. If you have control of the demand, you can also deal with local voltage problems. And that's something that you're going to need an actual bid into the market for.

Speaker 4.

This talk is a summary of two reports that we've done in the last few months. One is that ERCOT reserve market report, and the other is a study that we've done for FERC on the tradeoffs between resource adequacy and economics. These slides are way more detailed than I can cover in the next 20 minutes. But I think they are a good summary of what otherwise would be a 250 page report reading exercise.

So I want to talk briefly about when we might need a capacity market, or whether we actually need a capacity market, then go through some of the findings of the ERCOT report, highlights from the FERC Report, and a few concluding thoughts on what to think about before implementing a capacity market and the policy implications of all this.

So we've already heard, when do we need a capacity market? There are all kinds of answers, and I think everyone is right, because it's a combination of things.

First of all, let me say it's not a question of energy only markets versus capacity markets. It's really a question of whether you want to impose a mandatory reserve margin requirement onto an energy market. If you impose a reserve margin requirement, such as a 15% minimum reserve margin, then you have created a capacity market whether you like it or not. It might be bilateral, so then the question becomes, well, do you want to create some efficiencies by implementing an RTO-administered near term or forward capacity market? But the real deciding policy question is not whether you want a capacity market, but whether you want minimum reserve margin standards.

And why would you want that, given how complicated it is? Well, it does relate to missing money, but where does the missing money come from? Well, it often comes from energy market designs that lead to price suppression. The price caps may be too low to create scarcity pricing that reflects the value of lost load to customers, for example. There's often a poor integration of demand response resources. If you have emergency demand response, unless that demand response is setting the energy price, you get price suppression by dispatching demand response, reducing the load, and reducing the market-clearing price. That's all happening in RTOs today. There are often substantial locational differences that are not reflected in market prices, not so much in LMP markets, but the Texas zonal market had that. The California zonal market had that. And then there are various operational actions. Operators often make out-of-market commitments of units that get recovered through uplift charges. Those costs are not reflected in market prices, and so they mean energy market prices are too low compared to the marginal value and the marginal costs of the system.

But that's not the end of it, because there are some other challenges. We found that in very hydro-dominated markets, for example, you have very unusual risks. You really only get scarcity once in 20 years, when you have unusually high or unusually low hydro conditions. If you have a restructured market where private investors are supposed to make the generation investments, private investors often can't deal with such idiosyncratic risks, and then you might need a capacity market just to avoid these extremely tail-weighted price distributions. But you can also, of course, create distortions by out-of-market payments for some resources that lead to oversupply of the existing market. It's not a problem to subsidize renewables or hydro or something else, as long as you don't oversupply the market.

If the investment on the margin is a market-driven investment, you might get away from it, but if load growth is low, and there's enough existing capacity, if you then shoehorn subsidized resources into it, you basically create a missing money problem that leads to all kinds of inefficiencies, including the inefficient retirement of perfectly good existing units.

Ancillary service markets. As wind integration, for example, becomes more important, there's more money going to finance those markets. And if we are trying to get the energy market prices right, that's easy compared to the ancillary service markets, because we don't even know exactly what products we need for ancillary services. Do we need a flexible resource product? Do we need a ramping product? What is the right mix of products? And all of these things can create a missing money problem that results in underinvestment--but underinvestment compared to what? We've done some simulations I'll show you that says what an inefficient outcome would be. The trouble is that an economically justified reserve margin is often, I would say usually, less than the reserve margin that you would get with the one in ten standard.

So if you really wanted a one in ten standard on resource adequacy, none of these market based fixes can get you there. You can add money into the scarcity pricing and do a few things like that, but the reality is, if your resource adequacy preference is higher than what fully efficient energy markets would provide, you need to do something about it, like implementing a reserve margin requirement.

So with that preamble, let me go into some of the work that we've done. In the ERCOT report that many of you may have seen, we basically simulated, on a probabilistic basis, the kind of pricing and reserve margins that the ERCOT market, as currently designed with the scarcity pricing, with demand response setting market prices, with a $9,000 price cap, what that would get. And we estimated the economically optimum reserve margin on a risk neutral basis. The lowest cost outcome is about 10%. The current market design, because the scarcity pricing curve in some parts exceeds the marginal system costs, will give you about 11 ½%. And the one in ten reliability standard would be about 14%. So if you think 14% is what you need, the current energy market, even though we assume a fully efficient market with scarcity market pricing, demand response, price responsive demand, and all these things, wouldn't quite get you there.

So what would it cost to enforce a one in ten reserve margin at 14%? We've estimated that it would increase, on a long-run average basis, customer costs by about 1% of retail rates. Now, that is considering only energy and capacity prices. What's happening is really that the capacity price would increase customer costs by close to 10%. But if you go from 11% to 14%, you actually reduce energy prices by about 9%. So the net impact on customers is about 1%. But of course, if you put in a reserve margin requirement, you do have some other potential benefits--some risk mitigation, some DR integration. Some of the DR can enter the market more readily with a capacity payment. But you also face significant costs. If you put in a reserve margin requirement, it creates a lot of complexity, not just the complexity of the capacity market, but also defining what resource adequacy is and defining how much each type of resource actually contributes to that capacity.

So, we modeled 15 weather years with all the renewables going with it, and for each reserve margin point that we estimated, we have about 7,500 annual simulations of generation outages, all the things that you might encounter, to estimate what the various costs are for the broad distribution. And if you look at that, and most of these simulation results are being done for the one in ten standard, except that we also added economics to those simulations.

This just shows you that at 14% you had about 0.1 loss of load events per year, so that's the one in ten-ness interpreted by ERCOT. If you go down to an 11 ½% reserve margin, you have about .3. So you have about three times more loss of load events at an 11.5% reserve margin than at a 14% reserve margin. On average, overall outcomes, the worst year is always a lot worse, and the average is driven by the worst years, so you have to be a little bit careful with these numbers.

But just to put this into perspective, a 0.1 loss of load event where, on average, you shed 3,000 megawatts, that adds up to about one or two minutes per customer per year. So when we talk about reliability, it sounds like, "Oh my God, we need to safeguard reliability!" but resource adequacy is two minutes a customer a year. At the distribution level, customers face 100 or 200 minutes of outages a year. So let's not get too carried away by the difference between a 0.1 and 0.3 loss of load event number. But there are other financial implications that are very important.

So what this chart shows is (and EPRI has done this back in the '70s with some of its models), are total system costs across different planning reserve margins. The pink bars are the cost of adding new resources. We used CCs (combined cycle plants). You can use CTs (combustion turbine plants). There's not that much difference. So as you add more CCs to increase your reserve margin, you get certain benefits. You get a reduction of any dispatch of existing plants that have higher operating costs than CCs. That's that purple slice. You get reduced import costs. You get reduced demand response costs. You get a reduction in price responsive demand, which, you know, if price responsive demand cuts back at a price of $3,000 a megawatt hour, that's their value of lost load, so to speak. And the top slice in red is actually the load-shed events, which we valued at $9,000 a megawatt hour. And you get the lowest total system cost at about a 10.2% reserve margin. That's what we're talking about as economically optimum, risk neutral. There's a huge distribution around each of these cost points, because this is just the average over 7,500 annual simulations.

So what does that mean with respect to the reserve margin that you get in a market environment? This chart just shows you the average CC energy margin that you get at the different reserve margins, and the blue line is the cost of a CC, and it shows that you need about an 11 ½% reserve margin to get, on average, a profit in the market that covers your investment costs. But that 11.5% is quite uncertain. It's an equilibrium number, and even slight changes in sensitivities of the assumptions could make a big difference--you could be anywhere from 9% to 13% in equilibrium. And of course, you could have boom/bust cycles that have far wider swings than 11.5%, so even if you end up at 11.5% on average, you could be at 17% in some years, or it could be much lower in other years, because of how the economy adjusts, and because of how investors might be adjusting to the expectations.

And this is all interesting, because if you look at the difference between the blue line (the cost of new entry) and the red line (the "base case" cc energy margins) on the right, that's the missing money. If the red line is below the blue line, that means that that's money missing to make your investment back. So if you want a reserve margin that's higher than 11.5%, you have to put some money on the table in addition to the energy market, either through scarcity pricing or through capacity payments.

So if you flip that around, then you get the red line on this next chart, which is the capacity price at different mandated reserve margins. So if you mandate a 14% reserve margin, you get about a $40 per kW year capacity price, because that is the money that's missing in the energy market that you need to put on the table to allow investors to make back their investment costs.

If you have a reserve margin requirement of 11%, the expected capacity price is going to be zero. You can put in a capacity market at an 11% reserve margin requirement, but the energy market should take care of that, except where you go through boom/bust cycles, or the economy is adjusting, and things like that. So there might be a benefit to having a minimum reserve margin requirement of, say, 10%, just to be sure you don't fall below it. It still means that capacity will have no value in most years, but if you have an outcome where things drop very low…ultimately, this is not about economics. This is about policymakers' acceptance of unusually challenging market conditions. If you want a safety margin, you could put in a reserve margin requirement of 10%, and not create much of a capacity market, but use that as a safeguard.

So we talked about uncertainty. On the right of this next slide you see the average annual spot market prices, and a distribution of those prices. So if you take that 11.5% reserve margin, you see the average price there would be about $60 per MWh. That's about 20% higher than the price would be at a 14% reserve margin. But you see there's a huge distribution between the fifth percentile and the 95th percentile of possible annual outcomes. And, just as important, the median outcome is about $10 less than the average outcome. And the average is close to the 75% percentile, so in ¾ out of all years, you will have market outcomes that are below the average. And the other 25% of the years really what brings up the average. And if you look at what that means for the energy margins of a new plant, that uncertainty is even higher, because now you're looking at the profit margin, not at the price. So, yes, on average, you make your money back at 11.5, but in half of all years, you will be making back much less. That's a pretty big uncertainty if you rely on spot markets. Of course, you can hedge some of that uncertainty. But this also shows that the higher reserve margins drastically reduce the spread of the variance that you get from year to year.

So if we look at the supplier net revenues, the blue bars are the energy margins. The line is the cost of a new plant. And those pink bars are the capacity market revenues that you need to make up for the missing money. The dots tell you what your margins will be given the combination of energy plus capacity markets in the top 10% of all years. And you see there's a huge uncertainty. So even at an 11 ½% reserve margin, the top 10% are more than twice the average across all years, but about half of that you can hedge simply by seasonally forward contracting. Basically most of the stuff that you can hedge is weather uncertainty.

This slide shows total customer costs--that's what we talked about. There's some risk mitigation. There is a difference in capacity price between 11 ½% and 14%, but most of that is offset by lower energy prices (at a 14% reserve margin).

And a few words about the FERC report. There's a lot of discussion about one in ten, and how important it is to maintain a one in ten reserve margin. We've actually documented the fact that there's a wide range of differences in how the one in ten standard is applied. In most systems that use a one in ten standard (and not all do--the Southeast does not use one in ten at all, for example) it means .1 loss of load event per year. But even within that .1 loss of load event definition, we found that differences in how that is calculated and how reserve margins are calculated, gets you an up to five percentage point difference in reserve margin. So you can't really distinguish between a 10% reserve margin and a 15% reserve margin. It might be exactly the same reliability standard, just calculated differently.

But we think this is very important, because if you recognize how imprecise one in ten is, it gives you some flexibility, like a sloping demand curve. How acceptable is it to have a sloping demand curve that gets you below one in ten? Well, it might be perfectly fine, because we can calculate one in ten in different ways and get a wider range than most of these sloping demand curves get us.

So a couple of pointers on the FERC report on resource adequacy, which had some differences in scope from the ERCOT report. One is, FERC found that interconnections with neighboring systems have big impacts on planning reserve margins. You could get anywhere from a 10% reserve margin to a 16% reserve margin just by increasing or decreasing your interconnections with neighboring systems.

Demand response. We found that the optimal level of demand response is about an 8% to 14% range. But we also found that it's very important that demand response has to bid into the energy market to make this work, and there's decreasing value in demand response that either has call-hour limits, or has bid caps. If you have a 60 hour per year limit on how often demand response is called, the capacity value of that declines very rapidly. If you have economic DR that has a price cap of $1,000 MWh, it's basically worth less, because you use up that resource before you get to the scarcity periods. You have to allow DR to bid up to the value of lost load to make economic DR truly valuable.

Price caps and missing money. This slide shows three curves, which are average CT energy margins with different price caps. If you have a $1,000 price cap, you basically are so far off in equilibrium from an economically optimal reserve margin, you have no choice but to put in a reserve margin standard.

And the optimal economic reserve margin, surprisingly, depends on how costly it is to add capacity. If new capacity is very costly, the economic optimum is lower. It could be 9%. If capacity is cheap, it could be 13%. How come we are not discussing that? One in ten is totally ignoring the cost of new resources. And if you look at it this way, you can actually come up with a demand curve that is downward sloping that does not depend on the cost of new entry. Now imagine that, if it didn't have to fight about the cost of new entry.

So I'm out of time. But about capacity markets, I want to echo some of what Speaker 3 said. Don't jump to capacity markets prematurely, and don't do them for the wrong reasons. If you do them, don't discriminate between existing and new resources. It just won't work. It won't be efficient. Don't exclude DR or renewable resources. They have a role, and don't ignore locational constraints. Europe is going off exactly the wrong way on much of that. [LAUGHTER] And don't add a capacity market just because you feel certain resources deserve higher revenues. It's not about adding revenues; it's about creating more efficient markets. And don't subsidize resources that oversupply the market. And don't do it without fixing the energy and ancillary service markets.

Ultimately, it's a policy choice. It's not about one versus the other. It's really, what is our policy choice? What is the mandated reserve margin? What is our reliability requirement? How do we trade off risks? Do we have the tolerance to live with the risks and high cost outcomes that will have to happen in an energy only market? And I think if we opt for a reserve margin requirement, we really ought to be thinking through all these points very carefully. Many of the capacity market problems have been caused by going too quickly without thinking through all the nuances. Thank you.

Question: Does the loss of load event calculation of one in ten take into consideration whether the loss of load was based on lack of reserves, or a weather event, like the distribution system goes down, or something like that?

Speaker 4: Well, both. You can lose load because of big generation outages, or you can lose load before of hot weather. And often these things are combined. So it can occur for all kinds of reasons, including inadequate reserves, inadequate generation, but also just big swings in load that the system can't handle.

Question: Just so I understand…it also takes into consideration if the lines blow down?

Speaker 4: No, this calculation--it does assume interties to neighboring systems. But this is not a loss of load calculation that is related to one transmission line knocking out a substation within the system.

Question: Years ago I recall a New England situation where there were operating actions that were needed to bring reliability to the one in ten standard. Do you actually allow the one in ten standard to be met with those operating actions? Or how do you take those into consideration?

Speaker 4: No, the emergency actions, like even voltage reductions, are explicitly modeled. They're explicitly modeled as a system cost, basically with the rank order that you need to define the scarcity curve. For example, a depletion in the non-spin reserve has a cost, but it's less than a depletion in spinning reserves. It's less than a depletion in regulation reserves. It's less than an implementation of voltage reductions.

General Discussion.

Question 1: My comment is based on the description of the panel in the program, which I thought was very well done, "Carts and horses and parallel universes." And there's a statement towards the end about how the principle of the cart not being put before the horse dictates the priority should be on fixing the energy markets. But then the description of the panel goes on to say that most of the pressure is to fix old or found new capacity markets. And while I have my opinions, I'd like to hear what the panelists have to say about the real world consequences of the failure to follow that principle of not putting the cart before the horse, because it was a very interesting discussion, but if someone kind of heard a replay of it, they might get the sense that this is all kind of dry and academic, and not of any great real world consequence, when obviously from our perspective... But I think it will be helpful to underscore from you all's perspective sort of what the real world consequences are for failing to get the cart and the horse lined up correctly, and what kind of timing we have to work with--because if you think about it, this is 2014. This isn't 1995 of 2005 or earlier in the evolution of these markets. And here we are talking about some pretty fundamental problems and fundamental questions. So I guess if you could address first the real world consequences, and then the timeframe we have to address these issues before the failure to do so become very apparent and very costly.

Speaker 1: All right, I'll bite first. I think the short answer to your question is, we should have fixed this yesterday. We're, at least in New England, seeing the real world consequences of it now. Certainly we've got what I would call more traditional retirements that we all kind of saw coming over the last couple of years, having impacts on the operations of the system, with some of the older thermal units. But then we're having some of the more counterintuitive types of resources be impacted as well. And certainly one of those kinds of things that has happened in New England, and we're seeing in other regions, is retirement of some of the nuclear units. You know, Vermont Yankee has certainly been very well publicized in its challenges in Vermont and in the region, but in 2012, it ran at a 90% capacity factor and provided five million megawatt hours of base load energy into the region, and not only couldn't make money, but was losing money hand over fist. How does that work?

I think from an energy market standpoint, that's where some of these nexuses come in, and questions around getting those markets right and getting them right now. That is a challenge, and certainly as we talk about any of the proposals that I think we have, they're not ready to be implemented now. They all take certain lead times, which is in part why I think focusing to a certain degree on the energy markets today, recognizing that the capacity markets have lead times as the reforms occur, is where we're going to get the best bang for the buck.

But I completely agree. I think the urgency is real. We're seeing those retirements. And the question is, where is the next level and wave of investment going to occur? And what's going to support it?

Speaker 4: Well, the challenge I have with your question is, what cart and what horse? Because somebody's cart is somebody else's horse, and I think we have a problem here. Some people want to say, "Well, you have to fix energy market first." Other people say, "Oh, I have to fix the flexible resource commitment first." The other people say, "Well, you have to fix the capacity market first." And I think we ought to step back a little bit and figure out how the pieces fit together, and then plan how to get to fixing all these things over the long term. My problem is that people are jumping very quickly to quick fixes that just will make things worse over time, like this penalty factor in New England. It's going to create huge inefficiencies that delay fixing the energy market. Really, as Speaker 2 said this morning, you ought to fix the scarcity pricing system, not put something in place that is easy to implement but ultimately leads to long run distortions. On inefficient retirements--well, I wonder how Connecticut feels about the high-cost capacity contracts that they've signed now that other units retired, possibly prematurely, and now they're paying for both. They're paying full prices for capacity markets and the capacity that maybe was not all needed.

Speaker 3: I'll take a shot. First of all, hope springs eternal. We've sort of understood this problem for quite some time, but this past year we've seen so many things fail--we've now see the bid cap fail. We've seen price demand response programs not actually serve what we thought they were going to serve. And on the bright side, we have smart grid technologies, much faster computers. We can communicate better. We can actually deal with very small entities now better than we could when this was maybe an academic or more of an academic debate, and certainly if I were a nuclear plant, I would love to see myself getting higher prices in the energy market to essentially keep me from shutting down. I mean, it's a strange irony that renewable energy is going to shut down the nuclear plants.

Speaker 4: Well, is it that, or is it the low gas prices?

Speaker 3: It could be low gas prices, but certainly the renewables are causing a lot of problems for the nukes also, especially when they drive the prices extremely negative, and the nukes have to sit there and take it.

Question 2: Just an observation and a question. I think we finally have come to a point where the technology has caught up with the economic theory. I think that's sort of the theme behind this panel. But the question I want to ask the panel is, are we now taking reliability in the form of resource adequacy, which we've heretofore thought of as a public good, and are we really turning this into a private good through the use of demand response? That is the first question. And, second, is this, at the end of the day, just an academic exercise, given the fact that you've got governments coming in with RPSes that are going to create RECs, and you've got the production credit, which creates incentives for renewables to run at negative prices? And given the fact that we aren't pricing in externalities, and the fact that retail rate design hasn't caught up with wholesale market design and is likely not going to do so any time soon? So is this really just academic until we get those things taken care of?

Speaker 4: It's not academic, because we're not academics. [LAUGHTER] But more importantly, starting with your last question about how retail rate design hasn't caught up, well, you don't need a lot of price responsive demand to make it work. I mean, we looked at Texas and found that if you get a couple of thousand megawatts of demand response participating in the energy market, that's all you need to get the price signals. The price signals lead to bilateral contracting. You sort of get things going. If you have a $1,000 price cap, there's no incentive for competitive retail service providers to be very fancy about their critical peak pricing or whatever they can offer. But once you get better price signals, a lot of these other things happen, and what I found very interesting about Texas is that as the scarcity pricing and higher price caps were implemented, it was the generators who were bilaterally contracting with demand response providers to physically hedge their exposure to outages in the real time market. And, you know, if you have 70,000 megawatts of generators, and only 5% of them are hedging their exposure, you already have signed up, you know, several thousand megawatts of demand response bilaterally. And they will have a bid price, because these contracts work off strike prices.

Speaker 1: You touch on the tension that's been inherent in these markets ever since their development of a federally regulated wholesale market design, done on a regional basis, with individual state policies that sometimes, if not often, go in divergent directions. And how do we sort it out? And I don't have a great answer for you. I think you've touched on exactly the right tensions that we're seeing now and that are evolving. I think the trick is creating a market design that is flexible enough to hopefully be able to withstand some of those externalities that do come in either on an individual state basis, or otherwise, that insulate a little bit the actual market dynamics. All of that is certainly a lot easier said than done. I don't have a great answer for you on how exactly to do it, but I think that's now the challenge that is before us, particularly given the fact that I don't think we're going to see any of the jurisdictional lines that exist change any time soon. There certainly doesn't seem to be a will on either side to revisit that conversation.

So how do we try and integrate these things a little bit better? I think, again, the more specific we can be about what types of resources are necessary for reliability and the operations of the system, that will then make it a little bit easier to make sure that the markets at a wholesale level become reflective of the dynamics, and then, yes, you're going to have to layer on some of the retail purchases and other mandates that come in, but I think it allows a little bit of a better separation to exist and more certainty for resources to be able to participate. But it's hard. I don't know how we get there.

Speaker 3: To answer your private/public good question, the answer is, yes. And over the 30 plus years I've been a regulator, I find that once you declare something to be "the public good," it's an invitation for mischief, whereas private goods seem to take care of themselves. And I don't know how you do it, other than starting with getting the wholesale market correct, and then hoping that the states follow suit. I don't think the states can take the lead if you have a bad wholesale market design.

Question 3: Starting from the idea of getting the markets right, I'd like to throw in a slightly different market design angle and see what you all think about how that changes the story here. At the California ISO in the coming year we're going to be starting an initiative to create a new ancillary service, a flexible ramping capacity, recognizing that a lot more of the challenges of operating the grid are not just having enough capacity in the right places, but rather certain kinds of capacity. But part of designing the new ancillary service is also redesigning the cost allocation. So that instead of all of the costs of ancillary service being charged per megawatt hour of load and exports, to identify the facilities or entities attached to the grid who are adding to volatility, which is the driver of needing more flexible ramping capacity, and then using that to pay the entities that provide the flexible capability. And that seems to me to suggest at least the first step in a process of taking more of the expense of running the grid that has to do with balancing volatility and allocating those costs in such a way that the entities that create volatility pay, and the ones that can mitigate it get paid. So if we add that dimension to market design, how might that affect the story we've been talking about?

Speaker 3: It can't hurt. I mean, I think it's an absolute necessity, if you want to get things right. We've discussed this before, and I always have and desire to have a longer conversation about that, because again, I have a hard time understanding whether people are talking about defining a separate product that deals with volatility and defining separate uses that create volatility, versus having shorter periods over which we're doing the pricing, and so on. And so if you have five minutes versus an hour dispatch, and prices are changing rapidly every five minutes within the hour, and you have some resources which are flexible, so they can adapt to those prices, and other resources which are not flexible, so they can't, so they just get the average, it kind of takes care of itself, and you don't need to define a separate volatility product here. And so I'm not sure that I've been fully convinced that there really is anything, other than this problem that we always have some interval where we're averaging, and then within the interval, you have this problem that's going arise, but if you went to continuous time, it would sort of disappear. Now, you can't go to continuous time, but I think it's more just having shorter periods. When conditions are changing, you change the conditions. You change the signals, and then people who can adapt, adapt, and those who don't, don't. And you don't have to define it as a separate product.

Questioner: So you're saying maybe one minute prices and actually settling on one minute prices, or something like that.

Speaker: Yeah, I mean, we're moving to five minute prices, but in principle you could move to one minute, given the computing and the timing and all these kinds of things. And so is that the problem that we're worried about? The averaging within the interval? Or is it something else? And I'm not sure that I fully understand the distinction between the two.

Speaker 4: Yes, I think that discussion about flexibility needs is sort of the same discussion on a different time scale as resource adequacy. I mean, of course you can fix it through the market, but unless you have these five minute price signals that can reach the value of lost load, you're never going to get there, because I think you need to get demand response involved.

We know in MISO that aluminum smelters are providing regulation much faster than any generator can ever provide. But you don't get the demand response on renewable balancing without good price signals. So I think we do need better price signals. We do need to get beyond the $1,000 price cap. But I also think we're jumping too quickly to this idea that there's an absolute need for flexibility. I think we need to think about ramping as a tradeoff between shedding load, dispatching high cost resources, prematurely curtailing renewables to make the ramp more manageable… There are all kinds of options. And if I look at the Cal ISO duck chart, there's a huge difference between predictable ramps and unpredictable ramps, because if you know that every day net load is going to increase by 3,000 megawatts from when the sun sets, you don't need flexible resources. You can manage most of that through unit commitment. So there are layers of that, where I think we're jumping too quickly to putting in constraints, and putting in a minimum flexible resource requirement is just putting in another constraint that creates a new market that interacts with existing markets in ways we don't quite understand. And I think there, too, we ought to look at the interactions between these constraints and these markets in a more integrated fashion.

Speaker 2: If I had to choose between hourly pricing and creation of a flexible product that could adapt within the hour, and five minute pricing and no flexible product definition, I would choose the latter without a doubt. And then if I choose that, then I'm not sure I need anything more. That's the part where I'm confused.

Speaker 1: Well, we dispatch on a five minute basis, but we're too nervous about the prices, so that we average them over an hour, because we operate at that level.

Comment: For the load we do, but not for the generator.

Speaker 1: Well, but we operate at that level with a lot of uncertainty, because we have state estimators that guess, essentially, at what the parameters of the system are. Now, hopefully, we're going to put in all these PMUs, and we're going to get a lot of the noise out of the system, hopefully. But I haven't seen a big push to go to five minute pricing. I don't know all the details, because there are a lot of sort of things swimming around in the soup at the five minute level that I don't understand. So I get very nervous. I mean, in theory, yeah, it's a great thing to go to one minute pricing, but when I talk to our engineers, I get an earful.

Question 4: I've got two questions. The first one is, is there anything out there, nationwide or regionally, that says how much loss of load is because of distribution or events like a tree falling on the line and taking out a whole city, or something like that? Or how much of loss of load is actually due to lack of reserves? And then if it isn't out there, should it be? And then, are some of the loss of load questions actually dealing with the NERC rules rather than reserves? And then my second question goes to Speaker 4 on something I think I just heard you say, that one thing that you're seeing is generation hedging with demand response providers, and I just wondered if you can elaborate on that a little bit more, because I can certainly understand generation hedging or gas costs or those kinds of things. But in the markets we're talking about, I was wondering why a generator would hedge with a demand response provider.

Speaker 4: OK, I do have some numbers for you on your first question. These are not very good numbers, but there are some statistics out there. And based on what I looked at, distribution system outages count for about 90% of total customer outages. Resource adequacy/ generation adequacy-related outages account for maybe between one and three percent of outages, and the rest of it are transmission-level outages that are just a big line going down, knocking out a substation or something like that.

With respect to your second question, if I'm a generator, I bid into the ERCOT day-ahead market, say a 500 megawatt plant. It might be a hot day, and the day-ahead price might be $1,000 a megawatt hour. I say, "That's great, I'm committed to that." And then my plant has a forced outage, and the real-time price goes to $9,000 a megawatt hour. I have to pay the $8,000 per megawatt hour difference on the generation that I lost. And that's a huge liability. And all those dollars add up very, very quickly. So how do you hedge that? And real time is like, what, 15 minutes? So there's not a good financial product to hedge that exposure. One way to hedge it is to sign up with an industrial demand response provider who for $3,000 a megawatt hour, drops the load by 500 megawatts, and I hedge 6,000 megawatts of my 8,000 megawatt exposure.

Questioner: Just a follow on question--wouldn't you be able to go out and do hedging? In other words, a generator hedging their price does not need to hedge with the demand resource provider. I can see where you're going with that, that's one example, but they could hedge their price with a trading organization that provides risk management, those types of things, as well. So there are other ways for a generator to hedge.

Speaker 4: Yes, but most of the financial hedges are not applying to the real time market. They might apply to day-ahead markets. So there are just very few financial products available in real time, and I talked to several generators, and that's what they're doing, because that's readily available. It works in the real time timeframe. And industrials like it, too, because they get a reservation charge for being available.

Questioner: Thanks for that. That gives me some good ideas to take back.

Question 5: My question is a little bit more fundamental in nature, I guess. As we talk about what the price signals are for efficient markets, one of the big issues is how do you price penalties? And I just want to get apparent penalties for nonperformance, either of the generators or big demand response, and by various providers. How do you, from an economist's point of view, or depending whether you think you're an academician or not, how do you price nonperformance and to make sure the price signals are adequately giving not only incentives for adding new resources, but also for against nonperformance also in this case?

Speaker 2: Well, I think Speaker 3 said it earlier. My answer would be, if you get the prices right in real time, including scarcity and all the other kinds of things… Nonperformance to me means that you had an obligation to do something, essentially a contract to provide something. You failed to provide it, so it's an imbalance idea. You're out of balance with your contract. You have to buy back the service at the prices that existed real time when you're not performing. So the generator that's not available because of willful non-availability, or because of forced outage, or because they get struck by lightning, whatever the event, they have an obligation to meet, and they have to buy it back at the price, and if the price goes to a very high number, the value of lost load, it's going to be very expensive for them. And now you're done. You don't need a separate penalty scheme, as long as you've got the prices right. Where you need the penalty schemes is when you don't get the prices right. Which is where we get all tangled up in our own underwear here. I'm not going to give people the right incentives. I'm not going to give them their right prices. I'm going to tell them they have to do something. I'm going to have penalties, which look like the things that are the things that I can't do in order to make them perform. Fix the problem in the first place and get the prices right.

Speaker 4: Of course, if they are suppressed prices in the energy market, you might have an incentive to underperform, and then you do need penalties…

Speaker 2: They do have an incentive.

Speaker 4: …penalties for nonperformance.

Speaker 2: No, you should fix the prices in the energy rate.

Speaker 4: It might be easier to put in a penalty for nonperformance than to fix the energy price.

Speaker 2: I think the evidence is the contrary, that it's not easier. There's this assertion that's made all the time, but I don't think it actually is easier. I think it's harder. It's harder to design the penalties. It's harder to enforce them. It's hard to figure out what they do. And it's hard to deal with the unintended consequences. Whereas, if you're getting the prices right, that isn't that hard, and it doesn't create as much collateral damage. It's not perfect, but it doesn't create as much collateral damage.

I didn't respond to an earlier question before because I was mad. [LAUGHTER] But now I've calmed down a little bit. So I mean, as everybody here knows, this is not like the first time I ever said, "Get the prices right." And it sounds kind of boring, and you don't want to keep repeating it, but it's true. And when I was first talking about the Operating Reserve Demand Curve, I went around to lots of different RTOs and in front of FERC, and I said, "This is what you should do. This is what you should do. If you have to choose between capacity markets and scarcity pricing, do scarcity pricing. But you don't have to choose. You should do both, but the priority should be to do the scarcity pricing first."

And what I ran into universally was, "We're busy. So we have this scarcity problem. The prices aren't right in the energy market. We're going to have to create capacity markets. When we get perfect capacity markets, and we solve that problem, then we'll come around, and we'll figure out how to do the scarcity pricing."

And I said, "This is backwards. You've got the priorities in reverse order. You should do it the other way. Do the scarcity pricing first." Frankly, I feel unhappily vindicated. Right? [LAUGHTER]

Speaker 4: I do think we need to think about penalties in a way to set up a system that makes people rely on markets in bilateral contracting. You don't want to have a system where nonperformance is cheaper than contracting bilaterally, whether the energy prices are suppressed or not, that we have to think about. So if we just look at the capacity market, and I mean, I hate penalty prices in the energy market, because, as Speaker 2 says, scarcity pricing is so much more efficient. But if we have a capacity market, and we have a missing money problem because there are certain margins that are higher than what is economic and optimum, then if people don't show up with capacity, they ought to face a penalty that's high enough to make them replace the obligation in the market, and that's maybe a thought I have to add.

Speaker 1: And I think part of the challenge, if we're going to go down the penalty path, and not, as Speaker 2 noted, the path of actually getting the prices right, is then how do you set those penalty levels? Because in part what you're trying to do is mimic an otherwise well-functioning energy market and have the penalty then mimic what that price otherwise would be, and create the counterfactual penalty number coming out of it, which becomes tricky when you don't know what necessarily the price would have risen to in that event, if not for that penalty structure, and we start getting wrapped around the axel on it. And this gets even more complicated when we then layer on top of it what are the risks that we're trying to include here? Is it, as would occur in a truly well-functioning energy market, a case of, "You're not there for whatever reason, and so you didn't get the opportunity for that cost. You were never paid it, and you have to purchase it back in the marketplace"? Or, because we're now getting into a more theoretical pricing structure of what the penalties otherwise would be, is it that things that are outside the control of the particular resources are hedgeable risks? I think we start opening up a can of worms by going down the path of penalties that make it so extraordinarily complicate that I'm with Speaker 2. I think it is infinitely easier to get the prices right, work on the carrot, and not so much the stick, to make some of these issues happen and have the more efficient outcomes.

Speaker 3: Yes, and one of the things we tend to forget is that maybe initially we'll see some very big price spikes. But very quickly people will learn that they need to maybe do some extra maintenance to make sure they don't have a forced outage, or that the demand response is able to respond when the price gets too high. Today, if you're a consumer, you shrug your shoulders saying, "I know the price is never going to get above this level. So I don't have to care." And once the prices change, you're going to get a big feedback effect, at least I think it will happen this way. And prices will settle down again.

Question 6: I'm just trying to understand the relationship between Speaker 2's presentation and Speaker 3's presentation a little better. Are these two different approaches to slightly different problems, and then theoretically we could do both? Or are they two approaches to the same problem, and we ought to choose?

Speaker 3: There's no choosing. You can do both.

Speaker 2: I didn't hear the first part of the question.

Questioner: I'm just trying to understand the relationship between your presentation and Speaker 3's presentation. They both relate to missing money. But are those two things you could do at the same time?

Speaker 2: In principle, the answer is, you could do both, and in practice I would say that's maybe not a good idea here. So I think putting in a principle based Operating Reserve Demand Curve, which ERCOT is trying to do now, is a good thing to do no matter what, and it could go either way. But if you then make a decision that you are going to be concerned about resource adequacy, because this isn't enough, and we want to do something more, then I think I would be very nervous about trying to simultaneously tweak the Operating Reserve Demand Curve in order to solve 47% of the problem with the Operating Reserve Demand Curve, and then solve 53% of the problem, the remaining problem, with the capacity markets and all of the folderol that's involved with that. That seems to me like asking for trouble. And what I was pointing out was just that, if you think resource adequacy is a problem, and if you think that the Operating Reserve Demand Curve based on economics is not enough (the kind of analysis that Speaker 4 has done), that doesn't lead you necessarily to conclusion that the only choice is to go to a capacity market. The other thing you can do is to tweak the augmented Operating Reserve Demand Curve. In principle you could do both, but I'm not sure I would.

Speaker 4: Speaker 2, I was wondering, the way I heard the question, I was thinking about demand response more actively participating in the market.

Speaker 2: No, I thought the emphasis was on capacity markets, and that's what I was hearing. But if you're talking about demand response--yes. If you are talking about price responsive demand participation, I agree.

Speaker 3: Yes, right, it's a very specific part of the overall demand response. But what I see is the capacity market shrinking to a very small level, and it doing things like maybe keeping generators alive. I mean, in theory, you may need a capacity market, because of all the non-convexities and the lumpy issues and things of that nature. But the idea is to take as much air out of the balloon as possible, so that if you want to continue your capacity market, it's not that big a deal.

Speaker 4: Just to put some numbers on that, we've done some simulations on PJM, and integrating demand response into the price setting and energy market, we're doing a scarcity pricing that achieves the same effect, would take about a third of the money out of the capacity market.

Speaker 1: I think it's a noble direction to try and de-emphasize the capacity markets, and in many respects in our conversations, it does become the tail that wags the dog, but I think it's also important to recognize that even today, what is it, roughly 70 to 75% of a generator's revenues comes from the energy market. Somewhere in the neighborhood of about 10% comes from the capacity market. So even today, it's a de-emphasized market within the overall construct. Now, we spend so much time around it, because it is around that gap, that marginal amount of money that folks are trying to chase, but I think it's important to also remember that even as we talk about de-emphasizing it, it's not the main mover in the marketplace.

Speaker 4: Although it does feel like generators spent more than a 7th of their time working on capacity --

Speaker 1: I know I do. And I think it is, in part, because it is the most changeable that we're seeing right now in terms of both design, and again, that marginal amount of money that's out there to be captured. But I agree with you. We talk about it a lot.

Question 7: These markets are very complicated by their nature. The operational and financial issues that they're designed to address are very complicated. Speaker 3 mentioned earlier that we've seen, with current market design, some recent failures. I think you mentioned how the $1,000 offer cap became an issue. The seasonal aspect of demand response, when it's available, is an issue.

Another reality of these markets is that we have market participants that they need to work for. As a practical matter, many of the asset owners, generation operators, load serving entities, have limits on the complications that they can deal with in some cases. I was at MISO when we started our market operations in 2005. We considered rules like unobstructed deviation penalties to encourage generators to follow their dispatch instructions. My perspective was, you won't need those kinds of incentives or those kinds of penalties. Market operators will have a very strong incentive based on their LMP to follow their dispatch instructions. We roll into operations, and I found that many of our power plant operators, despite my best guesses, were not sophisticated commodity traders. And the prices and the signals that I thought would be sufficient sometimes were not, so I made some phone calls to talk people through why it was in their interest to follow the designs of the market.

So as you look forward to improving markets, getting prices right, with the prospect of demand response leading up to the value of lost load, the implications are that the prices could go from normal, $50 per megawatt hour a day, day in, day out, up to $10,000. So you have an incentive for a generator who fails to show up--the pain is, he pays the $9,000 scarcity price. That only works if he's got the $9,000. So just last month, during the polar vortex, both in MISO and PJM, we saw many hours, many days, where the claim price was in the hundreds of dollars per megawatt hour. The result was, we had hundreds of millions of dollars in margin calls. So as we move down this path, that's another potential area we've got to keep an eye on in terms of a potential area that could break. What's it going to take for this to work? Just a few large market participants that have the capitalization to participate and absorb that kind of volatility? Or do we need development of sophisticated hedging products for which my assessment is that many of the market participants won't have the sophistication or really the information to go out and acquire to protect themselves? So do you think the market participants can catch up quick enough with the transition? Speaker 3 mentioned a few spot prices that may cause people to take action, or that price spikes may cause market participants to take actions that prevent future price spikes. But do you think we can survive the transition?

Speaker 3: I think we've been fighting that battle for ten or 15 years. Everybody worries about the price spikes. And so we do things that don't make sense after the fact to suppress the price spikes. And that's simply the way we react, and people think that suppressing prices is a good thing-- not everybody, but there are a lot of people who think that that's the job of FERC, to put a thumb on the prices.

Speaker 4: Well, it seems to me that we just ought to make market participants more sophisticated than that. You know, to see that retail service providers go bankrupt because gas prices and power prices spike, to me that suggests that, well, maybe they should have thought about hedging or something like that. I think the down side of protecting market participants from price spikes is that you get a lot of people participating in the market that maybe shouldn't be playing in that market. And exposing them to price signals, maybe gradually, so they have time to learn, would be a good learning experience, I think.

Question 8: Which is more important? To actually get loads bidding into the market real time, in other words, loads in SCED (security constrained economic dispatch), which ERCOT is in the process of trying to do? Or is it the development of bilateral arrangements, or even what ERCOT would call "passive response," whether it's through a call option that load is sold, or whether it's just arbitraging the differences between day ahead and real time market? Which is more important? Or is that a false question?

Speaker 3: Well, from my point of view, getting the prices right, in the day ahead and real time markets, is really important, and since, once you do that, you expect the bilateral markets to take care of themselves, I don't see it as a regulatory function to engage in…I mean, maybe you do some talking about bilateral markets and hedging with people and things like that, but I don't see any active intervention in bilateral markets, or forcing people to enter bilateral markets. Now, you have retail markets under your jurisdiction also, and so that may be a much more important function for a state commission, to undertake that issue. But at the wholesale level, I'm not sure FERC would.

Questioner: I think maybe you misunderstood the question. I'm not suggesting that the regulators encourage one or the other. The question becomes, if a robust bilateral market, or just really trading, in effect, outside of bids into SCED by demand--if that develops robustly, do you even need loads in SCED?

Speaker 3: That's an interesting question. And right now, the operators would probably get very nervous, because they have to expect that demand to show up if there are high prices…

There's an interesting philosophical question as to whether or not the ISO should publish their look-ahead prices, which are today not binding, so that people can see what the ISO is expecting, at least, and some people are even thinking about binding look-ahead prices. But you know, it's a tough question, because if you see something happening an hour or so out, (and certainly the ISO has the best visibility, as far as I could tell, of anybody) scheduling the demand that can't respond immediately, or it takes an hour or at least a half an hour, is much more comforting than saying, "Oh, we see the prices going up, and we expect the demand will get off the system, and everything will be fine." And I'm not sure if ISO operators are there yet.

Speaker 2: I wouldn't require people to bid. I mean, all of these things make it easy for them to do it. And then you'll get the bilateral response, and some people will bid in, and some people will be passive. But the one thing that you do have to have in order to make all this work is *somebody* doing the demand side pricing and bidding it into the market, and that's one of the advantages of the operating demand curve, because it gets you over that chicken and egg problem, because if everything is passive, or outside the market, or bilateral, and there's no mechanism for the dispatch to actually reveal those prices because of the way the algorithms work, then you never get out of this trap. And so the Operating Reserve Demand Curve gets you out of that trap. And then if you ended up with 100% passive participation, given that you had the operating demand curve, and it was all bilateral, that wouldn't be the worst thing in the world. I agree with the comfort part for the system operators about having more knowledge, but you do have to have somebody participating, and that's what the ORDC does.

Speaker 4: One other thought. There is a lot of emergency DR that operators have learned to rely on, for decades, really. And I think it is important to get the emergency DR to pricing points, because the last thing you want to do is depress prices--you can slide down the scarcity pricing curve by dispatching emergency DR. And most of the DR, even in PJM, is emergency DR that doesn't really have much of a price, so whenever you dispatch that, you're screwing up the energy price signal. So allowing emergency DR to bid in the value of lost load, for example, is better than not having a price, and that is very important, and I think that's the easy part to do, in a way, because we already have all those thousands of megawatts of emergency DR. Adding a pricing point shouldn't be all that hard.

Speaker 1: Yes, and one tangent to that is, we've started seeing something that is rational behavior, but that is exacerbating some of the pricing issues, which is that because some of these actions, whether it's emergency DR or, frankly, other more day to day operations on the dispatch side, cause the real time prices to be depressed, that creates the incentive for load to then underbid in the day-ahead market, push more of their load as kind of a free hedge into the real-time market, exacerbating what in New England is already an "interesting" natural gas market, and exacerbating the issues around that, rather than truly bidding in their projection for real time load in the day-ahead market, providing a little bit more predictability, getting those prices right, and then allowing for better pricing to be reflected in the real time market. So it all, as usual, comes back to getting those prices right.

Question 9: I'd like to come back for a minute to the issue of flexible capacity. As the need for flexible resources increases, there are two questions that I'd like to hear the panel talk about. One is, what are your thoughts on whether those requirements for increased flexibility should be defined as capacity products, or ancillary service products, or some of each? And then, second, when you talk about those requirements and the cost allocation, is it more appropriate to think of those as costs that should be borne by the parties that are creating the need for increased flexibility, in other words, those who have the larger renewable portfolios? And the framework for that question is that, as I look at ancillary services right now, (and I might be wrong about this) I think, in most ISOs, ancillary services' costs are just allocated out to load on some generic allocation schedule. And so, for instance, for ten minute spinning reserve, the costs aren't allocated to long lead-time generators. They're allocated out more generically. And so is it appropriate to move away from that paradigm for ancillary services, because the need for ancillary services is changing into something that's much more granular than ten minute spinning reserves, where we have much more specific ramping needs and regulation needs and load following needs?

Speaker 3: In a sense, if you had continuous pricing, and you had really fast ramp rates, and things like that, the flexibility issue probably wouldn't be a problem. But I think what they worry about is, you get into this situation where you don't have the resources to balance the system, and then something bad happens. And until we get the pricing signals down to that level--and part of it is the look-ahead. I mean, there's a lot of uncertainty, and markets that don't have a lot of flexibility can get themselves into very difficult situations. And so you have to anticipate what's going to happen 30 minutes, two hours out, and sometimes you're right, sometimes you're wrong, and the system operators are doing it for you, and so you're actually scheduling the system to take care of what they expect could be the range of uncertainty, and things like that. So it becomes a very difficult problem.

Now, we have traditionally not allocated costs to generators. That could be a mistake, because sometimes the generators are the cause of the problem, and especially since they don't particularly want to move, in some cases, and because we don't want them to move, because they're low emission, and we don't price that into the market properly. So until we get all of the pricing right and get the stochastic issues corrected, I'm for saying that the flexible resources get paid by the inflexible resources.

Speaker 4: I think one thing Speaker 3 just said is important. If we go down the road where we charge ancillary services back to the parties causing it, there's certain load that causes some of it, by load uncertainty. But there are also conventional generators. If a big 1,000 megawatt nuclear plant goes down, a lot of ancillary services are held for those outages. But when it comes to the flexible load-following resources--yes, there's load and renewables, but if we go down that route, I don't think we'll end up in a place where ancillary service costs are only charged to load and renewables, because I think a lot of the ancillary services we have are because of generation outages and other factors. So that, I think, is something to keep in mind. Other than that, theoretically, if we get all the prices right, including the right products of ancillary services, we wouldn't need a flexibility requirement. But I think system operators are not very daring in relying on markets. They really want to know that three years out they have got all the flexibility they need, and even if markets could provide the right investment signals, I think the nice thing about these forward requirements are that it makes a whole lot of people sleep a lot better.

Speaker 2: I think this is a very good question, and I think it's a hard one, and I don't think we have thought about it enough. But one of the problems is that implicit in assigning the cost to the ones who are causing this cost is making a lot of assumptions about separability, as opposed to joint products, and we haven't articulated that very well, and I think it's a worthy subject that we should be giving more attention to. Recognize that in the getting the prices right story, the marginal cost of scarcity gets into the energy price. That's being charged to the load. It's being paid to the generators, and so on. It's the cost of the reserves themselves that we're not charging and allocating to the individual loads. That's a relatively small amount of the total dollars. I don't know exactly what the number is, but it's not that big a number.

Now, in principle, if you could do a cost causation story, you'd like to charge that to the people that are causing the costs for the reserves, and so forth, but it's not completely obviously to me that this sort of standard shorthand that we use for cost causation is actually right. As a matter of fact, I'm quite confident it's actually wrong. But saying that I know that it's wrong, because it basically comes off of a smoothness, separability, convexity kind of implicit model, which isn't true, is one thing. But then figuring out what is right, in terms of efficiency and so forth, that's another step, which I don't have a good answer for. I mean, I have some ideas about it that we could discuss in the future. But I think cost causation is something we use a little too freely, and we don't actually know what we're talking about when we say it, a lot of the time. And so I think we ought to think about it a little more. It's a good question.

Speaker 3: Yes, I don't think I've ever seen a cost causation debate that doesn't have multiple answers. Cost causation inherently needs a rule set, and you can have a huge debate over the rule set for cost allocation. And there's a lot of play.

I mean, the whole area of cooperative game theory is essentially cost causation, and it starts out with a bunch of rules. We'll calculate the Shapley value. Well, the Shapley value assumes that there's a whole bunch of coalitions that are doing various and sundry things, or you can do the Nucleolus, which is another set of assumptions. And so inherently in any cost causation debate, except the very simple ones, there's a lot of play to figure out things.

In the old cost of service days if you ever saw a 50% allocation of costs, you knew it was arbitrary, because they just made up the number. Or if you saw a 25% allocation of cost, again it was arbitrary, because they couldn't figure out how to do it right, so they just made up a number. And there's a slew of examples like that about cost causation, that you never resolve. The DC Circuit had a court case just this week where they had a big discussion on cost causation, and it's a little bit hard to unravel, but it sort of gives you the feeling that cost causation analysis isn't as precise as we would like it to be.

Question 10: I guess the question I have is, as long as we have this dichotomy, at least in the organized markets, between very sophisticated wholesale prices and extraordinarily primitive retail prices, how would scarcity pricing work, since the end users rarely see the price?

Speaker 2: Well, I think the answer that I would give is to echo what Speaker 4 said before, which is that the formal analysis says, get the prices right on the margin, not inframarginally. The inframarginal part doesn't matter. So if you have a lot of load that's basically inflexible anyhow, and they're not going to do anything, and you're not sending them the right price signals, the money matters, but it doesn't have efficiency implications. And you don't need that much demand participation in order to get a lot of these benefits, and if you can get them on the margin, then you're OK. But if you're missing that, then you've got a big problem.

Speaker 4: And I think it's a chicken and egg problem, because if you don't get the prices right, load won't go through the trouble to create the infrastructure to be able to respond to prices that don't matter. Right? So in some ways, get the prices right. And I can tell you, if wholesale prices can reach $9,000 a megawatt hour, a lot of investors realize, "Well, we can actually make money off that. We don't need to rely on stupid pricing. We can actually respond to that." It's a little bit harder in a non-retail access state, I think, but we see a lot of large customers be very sophisticated market participants, and you don't need that many megawatts participating or responding to prices to create vast improvements in market efficiency.

Speaker 2: And they should buy up those generators that are not paying attention. Right? [LAUGHTER]

Question 11: I have a quick observation and a question. The observation would be that energy markets have also got other problems, and I think Andy, if he was here, would mention the crusade on uplift, as he calls it, that PJM is engaged in this year. I don't really recall it being a problem in the past, but I guess last year it was. And one of the big concerns many people have this year is, if you try to fix one uplift by creating proxy constraints, you end up creating another uplift somewhere else, like FTR underfunding, which by my last count in January had exceeded a billion dollars, starting January, 2010.

The reason a lot of us care so much is that it connects to the viability of hedging in the energy market. Prior to the polar vortex, most of the hedging in PJM, because of renewables, transmission constraints, and local constraints, has been in the basis market. And the level of hedge ineffectiveness of FTRs in PJM has basically made certain kinds of hedges unworkable. So that's my comment.

The question is, if you're thinking of places like Germany and California, what would you offer policy makers there? I mean, is a capacity market or some construct not unavoidable? Because if you have wind and solar on the margin, what's the discussion on energy price formation anyway?

Speaker 2: Well, I was watching an International Energy Agency presentation yesterday morning, in which they were talking about how to deal with variable renewable energy and the arrival of all of these things and the high variability of dealing with all of these situations. And they had a slide, which I copied and sent to my dear friends, which said, "best practices." And it was ERCOT with five minute pricing and locational marginal pricing. So that's the recommendation to Germany, if you asked the question in Europe. And I don't think the recommendations to California would be different than the recommendations I would make to PJM or Texas or New England and so forth, or to Germany for that matter. I think it's all fundamentally the same problem, just the politics are different in each place.

Speaker 4: One thing I want to emphasize again is that it's not just a question of energy markets versus capacity markets. The big elephant in the room is that one-in-ten standard, and whether we want reserve margins of 15% that just can't be reached with economics, because it's just not worth keeping 15% purely based on cost. So, whether it's through NERC requirements, or through RTOs' interpretation of NERC requirements, as long as we hold onto that idea that we need to have a one-in-ten minimum reserve margin, we will likely always have a capacity market.

So I think it's also time to not just think about whether it's energy-only or capacity, but really, how should we think about reserve margin requirements? And I think that's a very hard one, because when we talk to NERC about the economic efficiency of the one-in-ten standards, they say, "Well, we're not about economics. We're about reliability." And when we talk to the RTOs, they say, "Well, we just do what NERC tells us." And nobody wants to touch the one-in-ten standard, except for ERCOT and the PUCT. But I think that is one of the problems in the room that we can't quite fix with efficient pricing, because it may not be the efficient standard to start out with.

Speaker 2: I agree with that. I think it's an extremely important observation, and I think the exception that you cited, which is Texas, is something we should all be paying very close attention to, because they have tackled this problem. And Brattle has been very helpful in this report that they're produced, and I strongly encourage you to go and read the 250 page version of it to understand it, because this is a critical issue. It's been around for a long time. And we've been walking past it, walking past it, walking past it, walking past it, whistling as we go past the cemetery. Eventually, this has to change. The only question is *when* it's going to change, because distributed resources, smart grids, variable…all the things that are coming are just going to chip away at the whole fundamental thinking that goes behind the NERC standards. It cannot be sustained. It's just a question of how long is this going to be before it's replaced with something else. And this event in Texas, and this report, I think, is extremely important in leading everybody to step back and think about this in a constructive way. And so I recommend it to you, and I hope we can all learn from it and benefit from it. I think it lays out the issues in a very helpful way.

Speaker 3: Just to comment on your pricing issues and the underfunding of FTRs, I don't think there's an easy answer, but there's an interesting debate as to how to try to reflect a lot of these things that are essentially caused by startup costs and minimum run costs and things of that nature. And you can't perfectly synch them up, so you have to make a decision on how you're going to do it and what the appropriate signal is. And there is a scheme in New York that takes care of some of those problems.

But there's no simple answer, because, you're right, once you tweak something, you end up tweaking something else, and it can't synch up. My own personal feeling is that reliability folks should focus on a much shorter-term horizon. That is to say, when you get into trouble, how do you manage the system into stability? And getting involved in what the right answer is related to the one-in-ten standard, to me doesn't seem to be an appropriate function for our reliability people. They should be more focused on, how do you curtail demand to keep the system stable? Because what you're really looking for is to make sure that you don't get a cascading blackout. Curtailing demand is not a great thing to do, if it's forced. But it's a hell of a lot better than a cascading blackout.

Question 12: Just kind of to summarize, it seems like one of the themes here is that there's a lot of price suppression. And we're trying to mitigate price risk for political reasons, or for whatever reason. But we're not actually mitigating that risk. We're simply transferring that risk from price risk into reliability risk. I'll call it the law of conservation of risk. All we're doing it shifting it around in a non-transparent way, from price risk into reliability risk, hence the reason for things like one-in-ten and so on and so forth. I think, to the point Speaker 2 has made, it's not a choice of scarcity pricing or shortage pricing and the Operating Reserve Demand Curve or capacity markets. They can both co-exist. But the overarching question is, with all of the distortions, with stupid pricing at the retail level, so to speak, with interventions from states and capacity markets, RPSes, and so on, how do we change the political dynamic so that we don't have this kind of rent-seeking behavior, so that we can actually get the prices right? How do we do that?

Speaker 4: With discussions like this.

Question 13: We were taught that all this restructuring happened, 20 some years ago, so we would have reliable system with least cost to customers. And what I'm interested in is, how does this system help customers keep their prices low with the reliability there? And so I'm told that we need the capacity markets. I'm glad to hear Speaker 2 say that might not be the case. But I'm really concerned in New Jersey. We have, in Maryland and the Eastern Seaboard, really high prices, and in our commissioners' minds, at least, and our staff, that's due in large part to the ISOs and how they regulate. So all this discussion is really useful, and we're moving ahead, and the Harvard group has helped move things along for 20 years. But to suggest that we need to get those policy makers out of the picture, maybe I misread Question 12, but that's how I took it, really bothers me.

Speaker 1: I actually heard Question 12 a little bit differently, and I think you raise the tension that exists in the way that this is structured, which is the bifurcated markets between wholesale and retail, the separation even within those markets between regulating the purchasers versus the sellers, all happening in different places, and us all trying to figure out, OK, how do we fit these pieces together? The short answer is, I have no idea, and if I knew, I wouldn't be here. Or I'd be on the beach.

I think the path that we have forward is, as Speaker 4 said, having more of these types of conversations, trying to provide a little bit more transparency into what are truly the issues, the gaps that are being identified, whether it's flexibility, whether it's mismatched rents, in terms of who are the cost causers versus the cost providers. And then identifying the areas within that that can provide some creative thinking to get there. But from a practical political perspective, I frankly think we're going to find ourselves in a situation where we kind of muddle through. It's a lumpy type of industry where a few large-scale investments can dramatically shift the situation from a net short position to a net long position, and vice versa on the retirement end, and it only takes a couple of investors to make either what some might view as a really smart investment, or others might view as a really dumb investment, to get us there.

If we look at it, we had a lot of these problems masked by the irrational exuberance that occurred at the start of these markets when all of the investments came in. Now a lot of that capacity is being burned off the system. We're having challenges because of the different types of resources that are coming onto the system, and we're having some of the more traditional base load resources operating as peakers and creating all sorts of operational challenges. But again, I think we're going to find that in all likelihood we sit back at this table in two, three, four, five years from now, and a couple of unanticipated investments come in to dramatically shift where we're going, and we are going to push the balloon, and there will be some other problem that we end up dealing with. But I think we need to look at it from a little bit more of a perspective of how do we make these pieces fit together, because we're not going to dramatically shift the jurisdictions here.

Speaker 4: It seems to me that there's a lot of education that also needs to happen at the legislative level, and it's not clear who the right people are to educate legislators. It might be the state utility commissions, because everybody else is just lobbying their perspective of these things. And I think, in terms of electricity prices being high, of course that's compared to what? New plants are fairly expensive, and if you are in a situation where you have a shortage, where you need new investment…you know, the fact that prices are higher in Eastern PJM than in Western PJM, where there's excess capacity, is not a bad thing. I mean, it might be nice if prices would be lower. But if you want investment, even if you sign long-term contracts, those prices are high. So in some ways I think legislators need to understand these fundamentals better to have a constructive discussion.

And, I mean, everybody here pays more for their cell phones than for their electricity. And what does it mean to pay 20% more for electricity? When cable bills increase by 20%, there's no big uproar at the state legislative level. Or, you know, if once in ten years you shed 2% of your load for two hours, what's the big deal? I mean, customers lose service much, much more than that. But it's all over the press. It's going to be "rolling blackouts." When we did our first ERCOT report, we avoided the term blackouts. We called it "load shed events." And the first question we got from reporters is, "What is load shed events? Is this rolling blackouts?" [LAUGHTER] So I think there is that education that needs to happen, and I think it ought not to happen at lobbying stages. It ought to be in a more neutral fashion.

Speaker 3: By the way, we've all, we talked about letting the prices go higher. But I really believe that letting the prices go higher has the end result of lowering the average prices. And so the bills that retail customer gets will be lower, although we seem to sort of over-discuss the higher prices. But I think you get better capacity. You might get less capacity. And when you see the prices, you move to places where the prices are cheaper. You move to off-peak and things like that. And so, overall, the hope is that you get lower prices, not higher prices. You get a few higher-price events, but overall you get lower prices.

Session Two.
Transmission Planning: The Challenges Ahead

Order 1000 provides some guidelines on how we should proceed with transmission planning, but the devil is surely in the details. How are we to make certain that the process is fully participatory without becoming so process-laden that effective decisions will be foreclosed? With the end of the right of first refusal (absent judicial intervention), how will it be determined who will build new facilities when no one has offered to fill a recognized void or where multiple parties are competing to serve the need? In fact, will transmission planners have to avail themselves of competitive mechanisms in order to ascertain what options should be pursued? How will we deal with all of the planning issues that arise from the increasing presence of intermittent, and often off-peak, resources on the grid? How will non-transmission line enhancements to the grid, such as strategic locating of generators, demand response, increased use of DG, and altered dispatching or dispatch protocols, be factored in? How might planning lead to fewer deviations from merit order dispatch? How different will the planning processes be in the various RTO market areas, and perhaps, even more interestingly, in non-RTO market areas? How will those differences affect seams issues? EPA regulations and the retirement of coal plants create short-term (in terms of transmission planning) uncertainties – which plants will retire and what transmission will be needed to meet reliability requirements? Shale gas is creating uncertainties in the resource mix going forward and in the definition of a contingency plan – what if your largest transmission contingency is on the gas system, not the electric system? How much coordination should transmission planners have with natural gas pipelines, and how should that be carried out? These are but a few of the issues that call out for clarity and resolution as we flush out the details of the new regime for planning the grid.

Speaker 1.

Good afternoon. First, I'd like to thank the Harvard Electricity Policy Group for putting this topic on the agenda, and also for inviting me to speak on it. I really appreciate that.

First I'm going to talk about the elements and the central question of the transmission planning framework that we have.

On this slide I tried to summarize the elements we need to think about in terms of how we go forward doing transmission planning.

How big of a planning region are we planning for?

What kinds of projects are we going to consider over what timeframe? We heard some conversation this morning about reliability planners planning for a much shorter timeframe. But what does that do in the long term? We didn't really talk about that, so I'll talk about that this afternoon.

What are the benefits that we think about when we think about transmission planning?

Of course, the huge uncertainties that we're facing. We've got not only the issues with the markets, but also demand response. We've got distributed generation. Energy efficiency. A lot of folks out there are telling us, “You don't need to build transmission, you just need to have enough energy efficiency, demand response, and distributed generation and all that this need for transmission will go away.”

What is the central question though that we're trying to answer? The central question really is, is transmission an enabler or a competitor? I want to talk about that a little bit because at my company we believe it's really an enabler, enabling all of these different resources to work together to keep the grid reliable.

But in order to do that, you need to understand those resources and the impacts they have on the system.

Our current transmission planning framework tool and methodologies rely on the traditional power flow models and stability analysis. People look at the summer peak, right? They look at that one hour of the year. They look at all the contingencies. Maybe they do a shoulder peak analysis. They're doing more of that now, especially in the Midwest with the wind that they're getting and the problems that that causes in the off-peak hours, but really the approach is not very sophisticated.

The planning region sizes included in current transmission planning tend to be individual utilities, occasionally an RTO, or a single state. But as one of our speakers said this morning, if you just interconnect to your neighbor you can reduce your reserve margin needs from 16% to 10%. That's a huge savings. That's something that people don't think about in terms of planning transmission right now.

The projects considered right now, they're individual projects. Every project goes in and gets approved, typically, by itself. MISO, I think, was an RTO that did a portfolio of projects.

If you're going to look at really solving some larger strategic issues, you need to look at portfolios of projects. Not just individual projects that solve one or a few local issues.

Timeframes. One, five and 10 years are what is typically used. Sometimes people will look out 15 years, saying they're trying to take a longer term strategic look. But the timeframe is really short and it lends itself to the smallest, least cost project that will solve the issue that's right in front of you but it's not necessarily the best long-term project at all.

The benefits they look at are basically reliability, keeping the lights on, which is job one, and connecting generation and distribution. Those are what most transmission planners across the country are looking at these days.

FERC has had Order 890 out there for several years calling for economic analysis, and, really, people are not doing economic analysis. The folks who are doing it are just doing sort of this barebones production cost analysis, which really isn't sufficient to determine whether or not you should be making those investments, if they even do it.

So a lot of what I want to talk about today is, how do we change this?

Let's talk about uncertainties. If they're dealt with at all, they're dealt with in a deterministic fashion. At best, people will do some sensitivity analysis around what they have. They will maybe look at a couple of scenarios.

I don't want to suggest that the transmission planners are not doing a great job. But their job is incredibly complex even before we had all these new uncertainties that we're going to be dealing with. They have to look at all the contingencies on the system. They thousands of runs they have to do, and all that data to interpret and to make the decision as to what's the best solution. And it's not an easy job.

Unfortunately, it's getting harder, and they don't have the tools or the training or the methodology to deal with the new uncertainties that are coming at them really, really quickly.

I borrowed this flowchart of the traditional planning process from EPRI. It's very deterministic. You get your load forecast, either from the generational planning group or you get it, in our case, from the customers and that's taken as gospel. Right? That's the forecast. That's what you're going to plan for. Maybe they look at an extra 5% of load, but it's all very deterministic. They've identified their critical contingencies using power flow analysis for thermal and voltage violations and stability analysis.

And they identify whatever issues they have, and then they try to find, again, the least cost solution to solve those issues, which is exactly what they have been asked to do for the last 50 years.

They're doing exactly what they've been asked to do, but now the world has kind of overtaken them in terms of the other things they need to consider.

So do we need a new transmission planning framework? What has changed? We've got markets. We talked about that this morning. They've enabled monetization of congestion costs, ancillary services, insurance costs, etc., but they've also changed the way that power flows on the system. One of the things we have seen is power flowing east to west, where it had never ever done that before, once the markets came into being.

The benefits are much more widespread. You can calculate them. Instead of looking at just individual utilities, you're now looking at a region, a MISO region, which is huge, or PJM.

Order 890 and Order 1000 require transmission planning to include economic analysis, calculating benefits, and considering public policy, and the cost allocation must be commensurate with the benefits.

If you're going to allocate costs of transmission based on benefits, then you really need to get your benefits right. And you need to look at those over the long term, not just the short term.

We have renewable integration, which gives rise to a benefit that we call “renewable investment benefits,” like being able to source off-shore wind or your utility solar where the resource is the best as opposed to where it might be closer to load, but not as good of a resource.

The need for greater resiliency is another consideration. We saw with Superstorm Sandy the need for greater flexibility.

And also the computing power and the algorithms enabled calculation of many more benefits than they previously did. Not only do we need a new transmission planning framework, but I think we have the ability to actually implement one.

What are those uncertainties? The markets are moving power in different directions. You've got renewable intermittent generation. We talked about that. The renewables are built at the resource not necessarily near the loads. EPA regulations creating uncertainty in the generation mix. Shale gas and natural gas prices are changing, creating unexpected retirements. We had a nuclear retirement in Wisconsin.

Demand side resources and smart grid, distributed generation, electric vehicle storage--we don't really know where that's going to go, but it's very big right now. People are thinking that the breakthrough is coming, and that's going to change things tremendously as well.

You can go out any day on looking at the news and see quotes like this, but one was from a discussion in ERCOT, where they're saying that you can't keep planning the way that you've been planning. You need to change the way that you plan for transmission.

From “Utility Dive” (quoting Jim Rogers): “The Internet of everything will transform the use of electricity…” Quoting Rob Binz: “The grid will be low carbon” and interconnected. Quoting Mike Chesser, we're going “from a one-way system to a two-way integrated network.” All of these things will put stress on the system and stress on the transmission planners.

I borrowed this slide from The Brattle Group. They did a study looking at the wide-spread benefits of transmission and how many benefits there are. This is just one of the many slides that they went through discussing all of the benefits that don't necessarily get accounted for in the planning processes that we have today.

Currently, transmission planners are focused on keeping the lights on, and that is what they need to do. There are very few economic projects, and often they're just looking to achieve a specific goal at the lowest cost. That's what they're incented to do.

People are only starting to learn how to plan for public policy. Some people are moving more quickly at that than others, but the point of this slide is that there are many, many benefits that come when you build transmission. If you don't count all of those benefits, you're not going to make the right investment decisions.

I want to talk about a new transmission planning framework. With respect to the tools and methodologies used, production cost analysis is a good start but it falls very short of assessing all of the benefits. Deterministic planning for reliability is not as reliable as it once was because there are too many uncertainties.

So we need a larger planning region size. We need interregional planning. This is one of those things that even the RTOs will tell you--it's a no man's land out there when you get to the seams. They're really not planning for the seams. In terms of timeframe, we need to look beyond 10 years. The benefits are long lasting and so we need to look at those benefits.

We need to look at portfolios of projects rather than individual projects. Planners needs tools and methodologies to deal with the uncertainties that they're coming with, whether they're planning for reliability, economic and/or public policy, or all of the above.

So, what I'd like to propose is a new transmission planning framework. There would be one category of project which would be, “Keep the lights on.” It includes shorter term solutions that I think we heard talked about a little bit this morning. They still need to do reliability planning in the way that they've been doing it, but they need to be able to deal with the uncertainties. And to do that they need some probabilistic planning models and tools and some training.

They can still, then, plan for the local utility and also regionally. I think that's appropriate for those sorts of projects. They can look at single projects to solve the need, the reliability need.

They can have a shorter time frame--one, five, and 10 years, and also look at the lowest cost alternative, but also consider some more strategic solutions in some cases. And consider the uncertainties with probabilistic planning.

But for another category of project, what I'm going to call “strategic transmission,” we really need a different approach. We need production cost analysis and economic analysis tools. We need to look at a wider variety of benefits. We need to calculate the full range of benefits and beneficiaries. We need to look at a longer timeframe. 10 to 20 years. We need to look at different policies. And we need to consider the larger region, especially interregional impacts, because that is where right now the transmission is not being built.

I think that, to start, we can consider the uncertainties with a range of plausible futures. Because we're looking out 10 to 20 years, because forecasts aren't any good, what we have done at our company is try to look a really wide range of plausible futures and try to bound the outer limits of plausibility, and then look at the performance of our proposed transmission projects in each of those different plausible futures to see whether they are a robust solution, a robust choice going forward, or whether or not they might be needed in just one or two scenarios.

There are some tools and methodologies out there, but they're not being used on a regular basis, and they're not being used, in my opinion, by everyone, and they should be.

In summary, I just want to make a few additional comments. For strategic projects you really don't want to have this dichotomy between reliability versus economic versus public policy projects. Instead, if you look at all of the benefits, you look at the reliability benefits, the economic benefits, and the public policy benefits, then you can make a more appropriate investment decision.

At our company, we actually do an analysis each year where we benchmark the last year to the market. We have a security constrained economic dispatch market model that we use. We put all our reliability projects that we built during the year into and out of that model, and we calculate the savings that they would create for our customers over the lifetime of the projects. We look at that. These are projects that were built for reliability. They were justified based on reliability needs, but what we found is that, over time, they will basically pay for themselves. They return 99% of their costs over their lifetime with economic savings. And the only economic savings we consider in this analysis are adjusted production cost savings and loss savings. So we're not even doing the full range of potential savings. But even with that, these projects are basically paying for themselves. So, it just makes you wonder, are we building something big enough?

As I was listening to the panel this morning I thought the concept of getting the prices right was key. When we try to do all the benefits, it's really complicated. And it's complicated in part because you don't have the right price signals in the market. If we were to get those pricing signals correct, as we talked about this morning, that would make it, I think, a lot easier to determine a bigger chunk of what the total benefits of transmission are, by using the economic dispatch models that people already have available.

Now, because the prices aren't quite right, you don't capture all of that, and so you have to do a lot of analysis outside of the model in order to try to capture some of the other benefits of transmission.

In summary, I think we need a new transmission planning model. Reliability still has to be priority one. But I think we could accommodate the reliability planning and do something in a larger, more strategic way. I'm not advocating a huge giant joint coordinated system plan sort of “Let's build out the super highway of transmission all across the nation” approach. I'm just looking at trying to identify portfolios of projects that will make sense in a variety of futures and that look at all of the benefits that can be had.

Question: When you talk about a “portfolio of projects,” you're just referring to transmission projects, right? Or, are you talking about a portfolio of all types of resources, whether they're supply or transmission?

Speaker 1: When I say a “portfolio of projects,” I'm talking about both a portfolio of transmission projects, but we also look at the variety of different combinations of resources you could have in terms of scenarios. So, looking at a future that's got more or less renewable, more or less distributed generation, that sort of thing. So we handle that with scenarios.

Questioner: But what I'm trying to figure out is what comes first? The transmission planning or the supply planning? Is the supply scenario an input to your transmission planning?

Speaker 1: Yes, it is.

Questioner: So, there are a variety of scenarios that you input and then come out with the transmission plan?

Speaker 1: Right.

Questioner: OK.

Question: You talked about how there needed to be better or more robust economic analysis. Could you elaborate on what, beyond production costs savings, you would urge be done that's quantifiable?

Speaker 1: Yes. First of all, in addition to the adjusted production cost analysis, we look the what we call "insurance value." We look at high impact, low probability events and how the portfolio or the project would perform under those high impact, low probability events.

Then we take those benefits. Clearly, you don't want to take that whole year's worth of benefits and assume 100% that that low probability event is going to occur. So, we take those and multiply them by the probability that that event will occur, whether it's 1 in 10 years, or 1 in 20 years.

Then we consider the duration of the possible event. It might be something that maybe only lasts a month or two, so you calculate a month or two worth of benefits, and multiply it by the probability. So we'd calculate the insurance value.

We also calculate something that we call "renewable investment benefit." It is the savings that you will get if you have an RPS in your state and you have a choose between meeting that RPS with in-state resources that might not happen, and sourcing from outside the state. In our case, it's wind is what we have in Wisconsin and the Midwest. We have a choice between sourcing from western Minnesota, Iowa, and the Dakotas, where they have a much better wind regime, or building those in Wisconsin close to the load.

Well, you need transmission if you're going to build them further away, but you also get a huge cost savings in terms of the number of generators that you need to build. If you're talking about wind generation, because your renewable portfolio standard says x% of energy needs to be produced by renewables, you can get that x% of energy with a lot fewer wind machines in the Dakotas or Iowa than in Wisconsin. And that can be a huge savings.

Questioner: Do you include any analysis of the impact of the potential project on local LMPs?

Speaker 1: That's actually the basis of the analysis that we do. We use the model called PROMOD. It's a security constrained economic dispatch model. What it does is it calculates those LMPs, around the system, for 8,760 hours a year. So that is our metric, which is the difference in those LMPs.

Questioner: I really meant local LMPs in addition to the overall.

Speaker 1: When you say local?

Questioner: If you've got an area that's constrained or is a pocket of some sort, and you build additional transmission, then you're going to affect pricing.

Speaker 1: Yes, that's exactly what we're looking at when we do our analysis, because we don't have just one central LMP in our analysis. I mean we have LMPs at all the generators and at the loads. So, we have the generators nodes and the load nodes.

So if there is a pocket like that, you do the analysis to see what you can do to relieve that congestion.

Question: You mentioned that you're looking at production cost savings as one element in your analysis. Now you're saying the difference between LMPs. I'm confused as to what the metric actually is.

Speaker 1: It's adjusted production cost savings, but looked at using the LMPs.

Questioner: Adjusted for what exactly?

Speaker 1: Adjusted for imports and exports to our system.

Questioner: OK.

Speaker 2.

I'm going to talk about transmission in a markets context, and to look at kind of the long road to FERC Order 1000, incorporating transmission in a market construct. It has taken almost 20 years to get to FERC Order 1000. It remains to be seen whether that's the end state.

Transmission is being built and will be built, but I think it needs some thought as to what's so difficult about putting transmission in the markets concept.

First, transmission planning and transmission additions are done in a lumpy fashion.

Second, these lumpy investments are made for an expectation of the future. You have to have an expectation about the future load –there will be so many renewables, there will be so many retirements…

The projection is not done for the next year or the next five years. It's done for a horizon year. That's the best practice for transmission. The horizon year is at least 10 years out. It could be 20. In the old days it was 30.

A case in point. The first transmission line was built from Niagara Falls to the city of Buffalo. It was 11 kV. It was a relatively short line. In that region there are transmission lines with different towers of different voltage levels--11 kV. 32 kV. 69 kV.

They were building it incrementally, whereas, if you did it a horizon year, you would probably build a 230 kV line for the year 1930 instead of starting from, like, the early 1900s.

Transmission planning is based on horizon year and it's based on expectation of the future. And it is lumpy. So, those are the three things of planning.

On the markets, the construct we have is that when transmission is congested, you have congestion rentals. People who hold the rights to those transmission lines get the FTRs, financial transmission rights. So if you were to do expansion on a pure economic basis you would build transmission up to just one megawatt less than solving the constraint, so you're getting the revenues.

If you do the horizon-year lump investments, you've blown away the price differential, and the person who builds the transmission gets no FTR revenues.

So how do you deal with that? Some people have characterized that as market failure. Bill Hogan has suggested for many years, maybe starting 10 years ago, maybe longer, that we adopt the Argentine model, which looks at how you put this lumpy investment in the market.

There are two key aspects of that. First, you have to quantify beneficiaries. And second, a percent of beneficiaries have to elect to pay for these transmission lines.

Bill has been a proponent of that approach for many years. New York was for the first ISO to adopt that in response to FERC Order 890. And

I was glad to see that in FERC Order 1000, FERC actually adopted, even ever so weakly, the beneficiaries pay concept.

So, the basic issue with transmission planning within markets is this question of lumpy investments and how do you manage that without market failure? And I think the Argentine model is a good way to approach that.

Just to give you a little perspective of how we do planning in New York and go into 890 and 1000, in New York we've tried to make transmission planning compatible with markets almost since the inception of the ISOs. We did planning on an all-resources basis. It was not just transmission. We looked at all resources and we looked to market solutions for reliability problems and issues.

We do what we call a comprehensive reliability plan, which looks out 10 years. And we look at what kind of market solutions are being proposed, and up to now the market proposals have addressed any potential reliability problems. For example, if there's a power plant retiring, we might see that there are two other power plants in the queue, which would address that retirement.

Now, we do have a backstop provision that if we see that there's a reliability need and a market solution is not forthcoming, our public service commission can issue a backstop regulated solution and the TO implements that backstop regulated solution.

So that's how we have incorporated the planning within the market concept. We look at the markets first.

Then FERC Order 890 said that we have to allow economic planning and economic transmission. We were ready. We adopted the Argentine model with some changes. One was that the ISO does define and identify the benefits. And the beneficiaries vote, and they have to vote for that project, and 80% of the beneficiaries have to say, “Yes, I will pay for it,” before that project is built and administered through the MISO tariff.

That brings us to FERC Order 1000. When we looked at FERC Order 1000 in New York, there was a lot of discussion on the right of first refusal (ROFR) provision. New York did not have a ROFR provision in the tariff. What we had to do was relatively minor adjustments so that some of the information was available to transmission owners before other parties. We had to make sure that the information and the actual needs and project qualifications were available on a more general basis. So ROFR was not a huge issue in New York.

On the regional planning, we already had that within the context of our response to FERC Order 890. There was very little that we had to do in terms of complying with that provision.

With the public policy requirements of Order 1000, we adopted the same structure as the we used for the economic requirements of Order 890. The ISO calculates cost-benefit ratios. And then, among the public policy projects, proposes one to FERC as the recommended project. When FERC approves it, then the state is responsible for other aspects, such as siting. So there are responsibilities for the ISO, for FERC, and the state.

For interregional planning, we had a process which was already established, the Northeast ISO/RTO Planning Coordination Protocol (the IPCP). The guiding principle there is that benefits and costs are calculated regionally. The cost cannot be allocated to a region which is not prepared to pay for it. So that's one of the principles. We have made our compliance filing. We are awaiting the FERC Order.

That probably brings us to the most interesting pieces of New York in terms of transmission. The last major transmission line which was built in New York was in the '80s. And people say, “Why is that?”

Just to give you a thumbnail, New York is really two states. Upstate and Downstate. Downstate wants reliability. They want the power plants near the city, near the load centers. Every time there was a blackout it was due to transmission, so they want generators close to the New York City area.

Upstate has no incentive to actually build transmission lines to send their low-cost power to the big bad city. So from the '80s on, there has hardly been any transmission lines built. Because of our locational pricing, it's easier to locate gas pipelines and gas plants close to the load center. We have built tremendous amounts of gas plant capacity near the load centers and we have not built any transmission.

It's neither good or bad. It just was the more economic option. The LMP prices work. I can tell you, in New England, which did not have LMP, a lot of the plants were built in Maine, while the load centers were in Connecticut and Boston. They had to build several billions dollars of transmission to get those plants to load centers. But of course New England now has LMP and there are better signals.

But in New York what we see now is that a lot of the transmission infrastructure, about 40% of it, needs to be replaced. Then there are considerations that all the renewables are in the north and the west. There is not enough transmission to bring the renewable to the load centers. The governor wants to shut down Indian Point, after the Fukushima disaster. That plant is 2,000 megawatts of highly reliable low-cost supply we had very close on the doorsteps of New York City. The governor is very interested in shutting that plant down. That would be 2,000 megawatts less in the Lower Hudson Valley. There are retirements of coal plants coming. With respect to fuel diversity, all the hydro resources in Niagara and elsewhere are in the western part of New York. So there is really a large impetus or need building for addressing transmission issues in New York.

The governor, being very proactive, issued what we call the Governor's Energy Highway request for proposal, which is a public/private partnership looking at different ways of unbottling the upstate north versus the load centers in New York.

So looking at current transmission proposals in New York, the first one on our slide is the governor's project. All the projects listed under that were in response to the governor's request for proposals.

Some of the interesting ones are the high voltage DC line, the Champlain Hudson Power Express, from Hydro Québec to New York City, and there are a number of 345 kv lines.

The other very interesting aspect of this is the New York transmission owners and the proposal for a Transco. As I mentioned, there has not been much incentive for the upstate utilities to build transmission to send power down to the downstate. But if they were co-owners of a Transco, they could build transmission which they would jointly own, which would address certain needs for the state, the controlled area's power grid transmission needs.

These transmission needs have several dimensions, including upgrading existing corridors and increasing the capacity of existing corridors. So there's a Transco project which includes all the investor-owned utilities in New York, along with LIPA and NYPA, which are state agencies.

We are waiting for state legislature approval before we can get LIPA and NYPA to participate in the Transco. But just as we have ATC and ITC, we might have a Transco in New York, so that's an interesting development.

Before I end, there are all these projects in New York. The question is, in terms of FERC Order 1000, it is still to be determined how these projects will go in terms of financing and cost allocation and cost recovery. They could come through our process, which is based on Order 1000, as either economic projects are public policy projects; they could go directly to FERC for recovery through FERC rates; or they could through the PSC and get recovery through the local tariff. The PSC can order TOs to build lines and put it in the local rate base. So it is still to be determined how any or some of these projects will be built and under what mechanisms.

To summarize, transmission planning has been difficult to incorporate in the market environment. I believe we have a framework for this in New York, but it remains to be seen what the end state is. Thanks.

Question: For the proposed lines that you have here, if they're all in-state would they still be FERC regulated? Or would it just be the state regulating them?

Speaker 2: Our transmission owners have the ability to take it to FERC and ask for FERC recovery.

Comment: Part of the reason for that has to do with the cost recovery for those projects and making sure that the cost gets spread to entities across the state. In contrast, with the retail rates right now, you're set up to sort of charge each footprint's customers for transmission. But the nature of the regional projects would be regional cost recovery. So that's where the FERC jurisdiction aspect may come in.

Question: So even though it's one state, FERC looks at is as regions within a state?

Speaker 2: By definition, because we have connections to New England and PJM, it is interstate.

Question: Is it the size of the line or is it more than that?

Comment: I think it's the wholesale transmission service aspect of it. So there are FERC approved tariffs now in New York for wholesale transmission service. This would be kind of an outgrowth of that. So there is FERC jurisdiction over transmission service activities in New York now.

Question: What's the criteria for deciding when to retire transmission?

Speaker 2: I haven't come across any proposal to retire existing transmission line.

Question: I think you said something about replacing transmission?

Speaker 2: Upgrade. Upgrade or enhance the capability.

Question: The criteria for that are?

Speaker 2: The criteria are that there's a lot of corridors which are congested, especially from, say, Albany south to the Lower Hudson Valley.

There's a corridor that leads to Pleasant Valley, which has wind, and some of the fuel diversity, so there are corridors which you could enhance, and the existing lines are old. So you could just refurbish them and bring them to their capability, or you could enhance their capability.

Question: I had a question on your Argentine model and costs. You said some percent of the beneficiaries have to vote on the project? The beneficiaries here are defined as load, generation…? Who are we talking about?

Speaker 2: In New York they are loads. It could be generators. I'm not sure, what they did in Argentina, but in New York it is currently loads. In New York, 80% of the load that benefits have to say, “Yes, I'm going to pay for this line.”

Question: Do you know many projects or how many millions or billions of dollars of projects have been approved under the economic projects terms?

Speaker 2: We haven't approved one yet. We evaluated a few, and they have not passed muster.

Speaker 3.

Good afternoon everyone. I'd also like to thank Bill and Ashley for asking me to share some perspectives on transmission planning and what some of the challenges are ahead.

I'll say I've been thinking about transmission planning holistically in terms of the need to get the transmission system to where it needs to be, which has all kinds of elements in it: financing transmission planning; siting; cost recovery. I'm going to look at all those aspects in my remarks today.

I'd like to organize my remarks in two buckets, the first being near-term challenges, which I view as really right upon us right now, and then the second bucket being longer term, more emerging challenges, which are those that we are already seeing the impacts on, but we can expect to see them more so in the future, so they're going to evolve over a longer time.

I think a really important challenge right before us is making sure that we keep the industry and policy makers and regulators focused on the transmission infrastructure and the need to keep that working well. Operating and planning for that, too, because of the lead times necessary to maintain and keep a strong transmission system.

We need this to support reliable power delivery, given the generation resource retirements that we're seeing, and the new generation we're seeing coming on. And generally to support efficient wholesale markets.

There is certainly a lot going on in our industry. There are a lot of opportunities and challenges, but it is key to keep moving forward and make sure we have a strong backbone transmission system. So it's important that we don't let that slip from the priorities along with all the other priorities that we as an industry are facing. I just want to give a support for the transmission system not to be neglected.

Near-term challenges that we need to meet as an industry include modernizing and replacing aging infrastructure. New York is an example of that. We do have a lot of aging infrastructure in New York, as one example.

The Edison Electric Institute estimates that about $14 billion to $16 billion a year in transmission system improvements need to be planned, financed, sited and constructed by member utilities in each of the next several years. So there's a lot of investment need out there across the country, including reliability needs stemming from generation retirements. These retirements are being driven by different factors. Aging plants. Increasing environmental considerations. Economic factors such as the impact of low gas prices.

As a data point, for New England, which is roughly a 30,000 megawatt system, we have 3400 megawatts of generation announced now for retirement, and 8,000 megawatts total coal and oil units identified at risk of retirement in the next decade. So it's a big issue for New England, and that's just indicative of what we're seeing either now or that we can expect to see in the future in other areas of the country.

Not only do we need to make sure that the system stays working through these generation retirements, we need to accommodate the new generation resources that are going to come and fill that gap.

To ensure that the transmission system gets the attention and the improvements needed in the near term, the fundamentals of what we need to have are clear to many of us. They really haven't changed, and at a high level they are, first, working and timely regional planning processes; and, second, clear and workable cost allocation and cost recovery mechanisms; and third, efficient siting processes. For the most part, these are working pretty well at the local and oftentimes at the regional level. There are different views on how well these are working for multistate or multiregional project needs.

I wanted to point out that there are a few things that could, if not addressed properly, really risk knocking us off track in the near term, as it regards the transmission system.

The first is the return on equity (ROE) challenges that the industry has seen. There are a number of challenges pending before FERC right now where petitioners are asking FERC to lower ROEs for transmission investments into the 8% and 9% range. These are material changes around 200 basis points or more from today's return levels. This, of course, causes uncertainty and impacts, or can impact, depending on how they are decided, the sustained focus on transmission investment needs. It's important to have sufficient ROEs to keep the industry focused on investment needs and to enable efficient capital and to support policy maker objectives.

Right now, it's in FERC's court to address these ROE challenges, but that's something that I think has a material impact on the transmission landscape right now.

The second thing I'll highlight is the transition to FERC Order 1000’s new regional planning rules. There are a number of new changes that are coming with these rules.

One of the major changes in many regions is introducing new competitive solicitation processes into the regional planning processes.

While we don't have all the final rules from FERC yet, we can already start to make some observations about the possible transition that we're going to be going through.

First of all, it may be complex, and I don't exactly what the percentage is, but not all transmission projects are going to subject to competitive solicitation. But even if something like 10% of them are, the effort that is going to go into administrating the competitive solicitations for that set of projects, we can anticipate, is going to be large, based on what we've already seen in putting the rule together. So we can anticipate that more time and resources will be spent on implementing and gaining experience from the new rules. With that, there will likely be challenges and disputes in executing the new rules.

We can take some early learnings from some of the regions that started to do competitive solicitations pre-Order 1000, such as PJM with their artificial island competitive solicitation. California has also done some competitive solicitations.

I sat in on a presentation from a PJM person last week, and the artificial island stuff is taking longer than expected. These are new rules. They have a lot of proposals before them, and frankly it's just going to take time to sort through and figure out how to implement the new rules.

Because we're already in a somewhat challenging and changing environment, it's definitely going to be important to make sure that ISOs have flexibility to address near-term reliability needs expeditiously. To the extent that there isn't time to go through a competitive solicitation, they may need the flexibility to turn to their local utility or an entity to make sure that we can address urgent near-term system needs.

Through this all, we certainly want to make sure that the competitive solicitations that do go forward work as well as possible. Because at the end of the day it's about bringing customer value.

And I do think that the transition to FERC Order 1000 new rules will not be simple, and it's going to be something that impacts in the very near term. It's already impacting the industry.

I'd also like to mention something that is a particular concern for the Northeast--addressing the gas infrastructure constraints that threaten electric reliability and also have had a significant impact to the gas and electric costs that customers are paying. What we are seeing in New England is the following. New England has a lot of gas fired generation. I think 30% was mentioned earlier today. (I thought it was more like 40% of generation capacity that is gas fired.) It is a significant portion. In addition, more than 50% of the new generation in the interconnection queue is gas fired. So there's a lot of gas load coming from the electric generation sector.

The New England gas system infrastructure wasn't designed to carry that load. It was designed primarily to meet the firm load of the gas distribution companies. So right now we're seeing significant constraints in the gas system to serve both the gas customers from your typical gas distribution companies, but also the electric generation load that's being fueled by natural gas.

This has reliability impacts. It has price impacts. It has environmental impacts that we're seeing right now, materially, in New England.

It has reliability impacts because there's less generation available, at times, for dispatch, often on short notice, because the units don't have fuel. They don't have the access to the gas that they thought they did.

It's having a large impact on price, both gas prices and electricity prices. So electricity prices have doubled, at times, this winter, on top of already high electricity prices, and gas prices similarly are really, really high in New England. More than $20 per million BTU, and going up to $80. That's had a really big impact on the Northeast.

This has environmental impacts as well. On cold days in January, for instance, about 30% of New England's energy needs was being served by coal and oil units. You can see this as having environmental aspects as well.

The good news is that the six New England state governors and regulators and leadership are very focused on this. They are working under a regional cooperation agreement. They're looking at adding additional gas pipeline into the region and also new electric transmission lines to bring in additional hydro and renewable power from Canada or northern New England. They've expressed interest in 1200 to 3600 megawatts of new electric transmission capacity, so that's probably one to three high voltage lines. We may see some RFPs for that in the future.

Also, they're looking at 600 MMCF per day of additional gas pipeline capacity. In my view, that's probably not enough to address the constraints in New England. Some data is showing you might need as much as twice that amount. So we're looking at a new big gas pipeline or a large expansion project as well.

The states have indicated they've reached some agreement on the concept to have cost support for both the electric transmission and gas pipeline provided through mechanisms in a tariff, potentially the ISO New England tariff. That would certainly be a new approach for supporting the gas infrastructure.

It's a big issue right now in the Northeast. It's impacting both gas and electric system reliability and prices. I think the key for New England is to keep a focus on this and keep working through the problem so we can figure out how best to mitigate the gas constraints and their impacts. In the near term, I think the challenge is to ensure that the industry keeps focused on the infrastructure needed.

But I would like to turn my attention to bucket number two, which is sort of the longer-term challenges around what I think of really as our mission as an industry of transforming our energy systems across the country to be flexible, resilient, affordable, and clean.

Our transmission grid plays an important part in this transformation. It serves as a resilient backbone for the system, enabling energy markets, and ultimately enabling those end-use solutions for customers who want to manage their own power needs, including with increasingly distributed or demand-side resources as well.

To achieve this, the transmission and the distribution systems are ultimately going to become more coordinated or integrated, each playing important roles to enable not only our large centrally scaled resources, but also those distributed generation and those demand-side resources as well. We need to do this all in a way that the system is operating reliably every hour, every day, through the seasons. It's, frankly, a big technical challenge.

We will still need all those fundamentals that I talked about earlier. Effective planning. Cost allocation rules. Efficient siting. Cost recovery mechanisms. But we will need them with new aspects to address some of the changes that we're seeing.

I think about them in three ways. One is getting good at setting policy goals and requirements across states and regions, and enabling regional or inter-regional solutions when those make sense. I think this is going to take more alignment across states and regions and regulators and infrastructure companies. I think that's just an area we need to evolve into.

The second part is planning for and operating and providing delivery services across our transmission and distribution systems in a way that's more coordinated. I talked about how we have seen increases in DR and DG. We will see more, and the need for coordination and integration, I think, will become larger, not only from a technical perspective, but from a markets perspective as well.

There is definitely more understanding and education needed around that technical side of operating the electrical systems in these new ways, as well as an understanding about how the rates and economic drivers work as well. So I think that's another area that we're starting to evolve into and we will do so more in the future.

That leads to my third part, which is ensuring that the regulatory policies really enable this transformation I'm talking about, including rate and cost recovery issues--rethinking pricing and the value of services for capacity and energy and ancillary services and how we ultimately provide these and price them to customers.

That's a lot. There are a lot of challenges I see when I think about the transmission system, and I look for our discussion.

Speaker 4.

Good afternoon everyone. I'm going to talk about the challenges of transmission planning by focusing on a variety of topics raised in the introductory paragraph for the session. It turned out it was a quite a long list. When I went through the list of questions or list of topics, I decided that I'd probably focus on a few given the time limitation.

If nothing else sticks with you, I'd like you to think about the transmission planning framework that I'm going to put forward, and it's a conceptual framework, but it has a lot of details, so I will try to spend some time on that.

Then I'll talk a little bit about comparing RTO regions and non-RTO experiences in planning transmission, and primarily I'll talk about the benefits of transmission and how RTOs and different regions incorporate benefits as they plan for transmission projects.

Then I will get into more detail about exactly what benefits we're talking about. Then, of course, I'll address interregional planning. Then, of course, competition in the regulated business with some experiences to share.

Here's the proposed transmission planning framework. We've sort of fine-tuned this framework through working with various different planners. They sound like a whole bunch of words on a piece of paper, but at each step we've actually tried this and tested this with various different planners.

The first thing, as you heard others here on the panel talk about, is the uncertainties in the world that we're faced today in the electric business. We started this process by actually working with executives thinking through possible futures and strategic planning for their business, and then we transformed this paradigm of how to use futures in, for example, strategic planning and resource planning, into the transmission planning space. We have now seen how this method of using future scenarios to help guide how to plan for transmission works, and we're hoping that we can fine-tune this over the next couple of years as we work through the kinks of this planning framework.

The first step in using future scenarios is to identify the key parameters that really drive the regional or interregional or generally transmission planning, and to consider the risk factors, the trends in the industry, and the uncertainties that are faced by planners and of course all the market participants in the region.

Then, a lot of times we get asked the question, "Well, then what?" Say you have five scenarios, six scenarios, maybe 10 scenarios. Then what do with all that? Do we then assign probabilities on those scenarios and then say, "OK, the highest probability future--we should plan our transmission based on that"? And then what do we do with all the other scenarios?

I think what we're trying to say is that as a corporate leader, you think about strategic planning using futures as setting up your future boundaries of what risks you're willing to take and what risk you need to plan for or you need to mitigate. It's the same thing with transmission. I think we can use futures and scenarios to guide us to think about identifying the fundamental systems that you will need regardless of future scenarios.

We are not recommending that we assign probability, because once you assign probability, you'll realize you assign probability to the scenario you highly predict, which is always the base case.

Anyway, the first step is to take into consideration the vision of what the future would hold, and then plan the transmission accordingly.

The second step closely follows that, which is, as you think about what the future might hold, you identify a few valuable transmission projects.

I like what Speaker 1 started to articulate and started to convey, that maybe we are too restrictive about thinking about economic projects, reliability projects, and public policy projects. As you heard her say, when she evaluates the economic impact of those reliability projects, they pay for themselves. So, could they have been economic projects? Probably.

So we don't think about transmission projects as siloed of types of projects. Instead, we think of them as highways that will increase competition in the market, increase the reliability of the system, so that the customers can benefit. And ultimately, hopefully, customers pay less for delivered power. That's how we think about transmission.

In that context, I'll talk more about the specific benefits, but the second step of the framework is to identify potential valuable projects, given what we think about the future.

And then, simultaneously, as you think about what we called the “solution stage” or the “creativity stage,” how do you then think about the kind of benefits these projects could bring? We also know, as you will hear later, that incumbents or local planners, that know their own systems, intrinsically know what those projects look like. They have watched where the market moves. They have watched where the congestion zones are. They've seen what the reliability-must-run units are and what the economic impacts are. They might not have sat down and run the model, but there is enough knowledge in the room, so to speak, to have enough guidance about what projects might be valuable.

So then, you think estimating the value of identified benefits. When I think of valuable projects, I think of benefits. Now, let's try to estimate what those benefits are.

Then the next steps sort of naturally follow. Once we have an estimated benefit, then we compare that to the cost, and then only after that do we think about cost allocation.

Every time I present this framework, people say, “Come on, really? Nobody's really going to wait till the end for cost allocation.” What I'm trying to put forward in the framework is to hold back on immediately diving into who the beneficiaries are. The grid enables a competitive market and therefore there are many beneficiaries of some of these projects. So the last point is to address the cost allocation.

On the topic of comparing the evolving RTO and non-RTO experiences, I think you've heard some already about how different RTOs have different criteria, and how different benefits are considered in the planning process. But regardless where you are, where the guidelines are, or how the rules are set, the same potential set of benefits exist for all kinds of projects. It's with that spirit that we put together a checklist of potential benefits.

Expanding the horizon. Given the lumpiness of the investment, we need to look at the longer term and understand uncertainties. In terms of expanding the horizon, through the scenarios of the future that I mentioned earlier, we can look beyond the immediate reliability needs and load serving needs, which are the traditional way of planning that Speaker 1 talked about earlier.

I just want to throw out a few examples of this. In the RTO planning processes, CAISO now has expanded their way of thinking about the benefits of transmission, which helped us provide you with a guideline or set of checklists of potential benefits. They include things like production cost savings. We talked about production cost savings earlier, but it turns out (and Speaker 1 also alluded to this), the conventional models are deterministic. They don't capture all of the potential production cost savings because they don’t incorporate high impact low probability events.

There are many other benefits to consider--operational benefits, reduced transmission losses… These are things that we need to think about before we model, before we start estimating.

Another example of different regions looking at various different types of benefits is MISO. Certainly with its multi-value project analysis in 2012, MISO looked at a variety of benefits, and, again, they included renewable generation investments and production cost savings, as well as reduced future investments in transmission, reduced planning reserves when you expand the system, etc.

And as you see in the next slide, the non-RTO regions have primarily focused on avoided local transmission projects, reliability-based projects, and production cost savings in trying to estimate the benefits of a particular transmission line or a group of transmission projects.

I guess the take-home message here is let's not limit ourselves in thinking that those are the only benefits to transmission, because every valuable project simultaneously brings many benefits.

Let me just start again by saying, OK, there was the traditional production cost savings. We talk about congestion relief, but also the production cost savings and additional analyses to make sure that the deterministic analysis that we traditionally use can be adjusted for some of the real life operational realities that we observe.

Another transmission benefit can relate to reliability and resource adequacy. As you heard earlier, in the capacity market panel, as we expand the system, as you interconnect your system with neighboring systems, or expand those pipes between the systems, you do gain reliability benefits, and you also avoid potentially higher costs of generation when you're able to locate generation in places that are potentially lower cost as opposed to in a higher cost region. Those are potentially resource adequacy benefits and generation capacity cost savings.

I just want to focus on a couple other things. Again, the whole point of this is to look at transmission from a holistic perspective, not siloing benefits in terms of what's reliability, what's economic, and what's public policy.

At the bottom of this diagram here, there's environmental and public policy benefits. This probably becomes increasingly more important as we think about retirements and as we think about emissions reductions and increasing renewable penetration in our grid.

Then, just another highlight. Even if you've gone through and identified all the benefits associated with broad considerations of cost savings, reliability, etc., specific projects still can have other benefits that directly address unique needs of a particular area. One example would be storm hardening. Maybe there are certain projects that are there just for the insurance value that Speaker 1 talked about, for just those situations that will occur maybe once in 10 years, but when they do occur, the transmission projects, looking back, become extremely valuable.

So we recommend that policy makers and planners use this checklist (that's actually included in the appendix of this to document), to evaluate possible projects and communicate a comprehensive set of benefits for transmission.

There are basically two camps that say, "Well, you just want to build more projects. You just want to build more transmission, right?" One is load, which doesn't want to pay for higher cost of transmission. And the other opposing camp would probably be landowners. I think landowners are probably one of the strongest opponents of transmission.

So those opponents of transmission might urge to you be conservative and maybe assign zero value to difficult-to-estimate benefits. But, for rate payers, if you want to be really conservative about your estimates of benefits, you're basically saying that omitting certain benefits would be OK, because rate payers can just pay a higher cost of energy, because we don't want to have them pay for transmission. They can bear the potentially higher cost of energy. So be careful when we start thinking about “Well, let's be really conservative in how we evaluate benefits.”

Then, when it comes to landowners and right-of-ways, if we need to build transmission in a certain area, wouldn't it make sense to think longer term, wider range, broader scope to use those very, very valuable and hard-to-come-by right-of-ways? If the landowner has to be inconvenienced, and experience all of the other things that they complain about, shouldn't we be very careful about using those right-of-ways when we do build transmission? Perhaps we don't just build incrementally one of the earlier speakers explained was initially done in New York. And in a way we're still in that world of incrementally building transmission.

The next topic is about competition. When we start thinking about competition, we have to be careful about delineating the types of project that should be or could be subject to competition, and we have to be careful about creating an incentive for some incumbents to say, “Well, these are all reliability projects, because if I can protect the reliability projects, then they're mine, so maybe we should just build reliability projects.”

If we create incentives to do that, we're essentially going backwards, in my mind. So, instead, I'm sort of pushing them a little bit and saying, “Let's think broader scope, longer term.”

On interregional planning, we heard repeatedly that there aren't really interregional projects or proposed projects that have been approved. So I think this is the opportunity to really think about how we want beneficial projects to be designed and developed interregionally. Because we know of seams that can be bridged, and we know that they could be valuable. Let's not use the rules that are in the books to set barriers for interregional projects.

Here are a couple of slides on competition, because I think we're moving into a new game, so to speak. Many of the incumbents are trying to figure out how to compete in the business that's theirs, and those who have been waiting to have the competition open up are dying to get into other areas and compete for those.

I think the takeaway here is quite simple, but I think the story is just beginning. We have some experiences to look at. You heard about California and PJM and we certainly have heard it from Brazil. Ontario had a solicitation and selected a bidder. Alberta has a project right now that's open for competitive solicitation. The paradigm around this is, there's a solution stage and there's a project development stage. Really, I think the right words are the “project proposal stage” or the “project solution stage” as opposed to the “engineering” and “construction” stage. Because the competition in those two phases are quite different.

I'm going to skip this slide but this essentially talks about how we delineate what is allowed to be competitive versus not, and where can we introduce competition and not, certainly in the US.

This grid essentially shows how we catalogued, across the various different markets, where competition has been introduced to transmission, and these are the criteria that are being using during approval qualification and in the evaluation stage and the selection stage. You can see there are different criteria, like experience, design, schedule…all of these, in addition to cost. So the cost is not the only criterion. Certainly, different regions weigh the criteria differently, and the processes are different, but, overall, here are some examples of various experiences, and here are some business models of companies that are competing for these projects.

But, primarily, I want you to think about well, competition at the engineering and construction stage, how much cost savings would that bring us? It might be quite labor intensive or at least process intensive and maybe cost intensive to try to design these solicitations to introduce competition. How would that compare to bringing competition at the idea and the solution stage? Because I believe, and conceptually it makes sense, that that's where you get the cost savings, not necessarily at the engineering and construction stage.

Because, essentially the labor and the materials, the engineering and construction are the same pool, whether it's Company A or Company B bidding for it. They're drawing from essentially the same pool. But if we can allow competition at the idea and the solution stage, but making sure that those who come up with those solution and ideas can kind of keep some benefits (you've got to protect the rights of those who come up with the ideas), I think that's probably where we can get the best savings from competition.

Question: Do you have a place where you look at competition and contract risk in terms of fixed costs versus variable costs?

Speaker 4: That's a good question. The one thing to note is not all the solicitations only base the criteria or the selection on the cost.

So, yes, certainly, if someone can bear more of the risks and reduce the costs, they probably have leg up, so to speak. But I think, if it's just an engineering and construction phase contract, I'm not sure how much benefit we're getting from the competition. It's just a sort of question for us to think about.

General Discussion.

Question 1: Speaker 4, this is a fine-print question. Go back to your framework and the graphic. You had the different steps laid out. There was a lot of fine print which I couldn't actually read, but I was wondering if you could explain it. So could you put the graphic back up?

On your second slide, the third item is "estimate the value of the identified benefits," and I think what it says in fine print is, "without regard to the distribution of benefits."

Speaker 4: Correct.

Questioner: Unless I misunderstand what's being said here, almost inherently the point of transmission investment is that it changes the pattern of us and it changes the distribution of benefits across the system. If it didn't, you wouldn't need it. So what does it mean to say you are estimating without regard to the distribution of benefits?

Speaker 4: It's tied to the next block, which is to look at the value of the benefits from a societal perspective.

Questioner: Right, I agree with that.

Speaker 4: So the idea is not to directly jump into assigning benefits--"Oh, this generator might get more profit because it could sell in a higher-priced market." Or, "This load might pay less because now there's lower cost from somewhere else."

The idea is not to jump into that at the third step. To just quantify, and estimate the overall societal benefits.

Questioner: Right, but you would agree with the point that in the process of estimating the overall societal benefits you necessarily estimate the distribution of benefits?

Speaker 4: You necessarily distribute.

Questioner: You don't assign the cost, but you do recognize, if you build the transmission line from A to B, that the customers in B get benefits. The generators in A get benefits. The generators --

Speaker 4: I don't think you necessarily distribute. I think you *can* distribute. Because I think it's back to what your point is, is that just because we calculate the production cost savings or say, "So and so might be benefitting because they're getting lower cost, or someone's benefitting from higher profits" doesn't necessarily mean the sum of all the parts jointly create the sum of the societal benefits.

So it's not necessarily the case that you automatically distribute them. I think you can. You can try to distribute them, but my recommendation is to not do that at the early stage.

Questioner: This, I think, is a really important point here. The last step of doing the cost allocation is a different question. I agree. And you do want to look at the economy-wide societal benefits and so forth. I think that's the right thing to do.

What I'm concerned about is the statement that's been made many times, which is that you can't estimate the distribution of benefits. Or, this is sort of related to that, the statement that you don't have to worry about the distribution of benefits.

My argument is that it is not possible to estimate the societal benefits to compare with the project cost without simultaneously estimating the distribution of benefits.

Speaker 4: I would put it differently and say it's not that you can't, it's just that we recommend to look at the holistic benefits of the projects, because there are many other benefits that might not be estimated yet.

That's why it's important to not immediately jump into conclusions about, "This benefit belongs to so and so, and this benefit belongs to so and so," because there are other benefits that we cannot and probably should not try to distribute across members.

Questioner: Well, we can agree to disagree. [LAUGHTER]

Question 2: There's been a lot of discussion about multiple values and multiple benefits. Any reliability project can be displaced by local generation.

So how do we keep from double counting? Since you can displace any transmission project that's built for reliability with local generation, is that just an economic tradeoff? So doesn't everything devolve to economic tradeoffs?

Speaker 1: I'll take a shot at it. Everything devolves into an economic tradeoff. The question is OK, every transmission project could be displaced by local generation. That's true. I mean that's the center station generation model that we have right now and are moving away from.

But the point is, what's more cost effective? If what you want to do is look at the possibility that you might have local generation and not need transmission, you can construct that as a scenario and then see what the total costs are and see what your better choice is.

When we at my company do scenarios, we put a variety of different generation configurations into the model. If that's one that the stakeholders are particularly interested in, then that's what we'll look at.

Questioner: My point is that the reliability benefits can be translated to economic benefits that don't have to be counted separately.

Speaker 1: That's absolutely true. You can also do what we call "avoided" reliability benefits, which is, assuming your mix of generation, what lower voltage fixes are required for reliability.

Then you can do a larger, more strategic project which will eliminate the need for some of those. And we have used that.

Questioner: Why do we have all those slides with multiple benefits if you can devolve everything into economics?

Speaker 1: The reason we have all those slides is because people don't do that now. [LAUGHTER] That's exactly what we're trying to get them to do. [LAUGHTER]

Speaker 2: One of the things that we do in New York is to look at market solutions for reliability. Only if market solutions are not solving the reliability benefit, then you can go to a regulated solution. In that regulated solution, whether it's a generation or a transmission solution, you look at which is the more economic. And then you choose the more economic one.

Now, as far as benefits, in FERC Order 1000 compliance projects, which are public policy projects, we try to look at things which we can quantify economically. These are reductions in product costs, reductions in the capacity market procurement costs… And there's a list of things that we look at economically.

Then there are other things that may be very qualitative. Environmental benefits. Jobs. Whatever it is, you put with the others and those are qualitative and you add that.

If the benefit/cost ratio is less than 1, and there's a public policy, then, first of all, the public policy has to be aligned with a quantity which is not economically identified. Then you choose the best project economically, and then you send it to the regulator, which is FERC, to see that this is the one that has the best economic value which addresses the public policy.

Question 3: I'm actually going to go back to Question 1 here about the distribution of benefits. I'm glad the slide is still up.

In my mind the cost allocation mechanism is actually a necessary condition before you even think about this. So let's think about how costs are allocated today. Here in North America we generally like to peanut-butter them over the large part of load, but if you go to other parts of the world, they use different methodologies, such as megawatt miles, that are allocated to both load and generation.

So if we're talking about projects that are not reliability driven, but are market driven or public policy driven, why not have those who are benefitting pay the costs?

As the first questioner was pointing out, there's going to be generation that's going to benefit, if they're upstream of that new transmission line., through higher prices, and the load downstream from that former congestion is going to actually benefit through lower prices. Why don't we allocate cost to those folks?

The same is true for an RPS. Hey, the wind generation wants to be connected? They want to deliver that? Why not have them pay for part of the transmission and have the load that wants the public policy pay for part of it?

Something that Speaker 2 mentioned is that in New York it requires 80% consensus before you can actually get some of these transmission projects built.

So my question is, why isn't the cost allocation a necessary condition, number one?

Number two, in looking at forecasts, why do we want to pull the trigger on transmission projects when there's a real option value to waiting for new information?

As Question 2 reminded us, conditions may change, such that all of a sudden the forecasts look really bad--and we had two 500 kV projects in PJM that were cancelled, in part because economic conditions changed (Marcellus shale gas), and we had new generations being built downstream, which is substituting for transmission. So why do we want to pull the trigger on that now? Why don't we just wait and see what's going on?

Finally, with all of these insurance benefits--this goes back to the question I asked in the first session--is transmission reliability a public good? Or is it a private good? Can we turn this reliability into a private good where people can actually take care of that themselves? That's a lot to consider.

So that's open to everybody on the panel.

Speaker 3: I wanted to respond to the cost allocation bit and the beneficiaries bit. I think that to the extent that you can identify beneficiaries, then it makes sense for the cost allocation to follow.

I think part of what Speaker 1 and Speaker 4's presentations were talking about were the broad benefits that transmission brings. So to the extent that you're looking through a narrow lens of beneficiaries and you allocate it accordingly, if you're not capturing all the benefits that it's actually delivering, then maybe that cost allocation isn't working right.

So the tendency for some areas to spread the cost, if you will, I think is more of a recognition that it's quite difficult to measure beneficiaries with precision. I think when you get broader and think about different aspects of beneficiaries, I think theoretically you should be able to do it, but in fact it gets pretty tough. I think if you look at it through too narrow of a lens, you feel like you're doing the right thing by identifying a set of beneficiaries, but actually you haven't really captured the whole picture.

Speaker 1: I'll talk about the contingent risks--you were referring projects that were in and out of the PJM plan.

We look at a variety of futures and really look for futures that are sort of at the edges of plausibility as opposed to a base case. Then, we don't actually assign probabilities to them. And you don't have a base case because if you have a base case, everybody just gets wedded to it--and you're right. Things change. The future is not the way that we forecasted it.

So if you do your analysis of your projects or your portfolio projects against that range of really very different futures, then you can see which projects or which combinations of projects perform well in all of those futures, and you can provide that benefit cost ratio that you're looking at after you look at all the benefits across a wide enough region. And that way you can move forward with those with the confidence that they're going to be needed in a whole variety of futures.

If you have something that only works in one or two futures, then you do the real option choice of waiting to see whether or not that future develops. If it does, then you're ready with that project, but if it doesn't then you can leave it behind.

One of the things that I find problematic about how we plan right now is that fact that in PJM there is that bright line. You're in, you're out, you're in, you're out. From my perspective, that's a problem for investment certainty, and also from a system perspective.

And because it's based really only on reliability, it doesn't really take into account all of the benefits that are being provided.

I bet if you did a full blown benefit analysis of those projects they might be very beneficial to the PJM footprint even though they're not absolutely needed for that bright line reliability test in a particular year's analysis.

Also, I just want to correct something I said in response to a clarifying question earlier about whether we're using adjusted production costs or LMPs. I gave sort of a partial answer.

I said, "Both," and actually that is true when we were first doing our analysis. We knew that if you look at the adjusted production cost benefits of a project, that's really the lower floor. It's really something more than that.

If you look at the load-weighted LMPs, that's sort of an upper floor. So, initially we were weighting those results in our production cost model as 70% adjusted production cost, 30% load weighted LMPs.

We found after a while that even that didn't work, so what we started to do was to take one of those two metrics, the adjusted production cost, and make appropriate changes, adjustments to it for imports and exports, the impact on FTRs, and a variety of other things that don't get captured in the PROMOD model.

We call that the customer benefit metric. What we found was we could start with either the adjusted production cost and make the appropriate adjustments to that, or the load weighted LMPs, and you would end up with the same answer, once you took into account things like the FTRs and the imports and the exports. So that was the right answer to that question.

Speaker 4: I just wanted to supplement that it's not that using this approach would get you away from the option value. Actually I would say that using this approach actually helps you identify projects that could have an option value and perhaps if you see that under certain scenarios it's better to wait, or you're not sure what would materialize, those are the projects that you probably want to wait.

So actually the scenario-based approach allows and provides more of a systematic approach to identifying projects that you might get a higher option value by waiting for a couple years. And the analysis actually can show that.

Speaker 2: In New York we also assign beneficiary-based allocation to reliability projects. Again, there is sometimes a tendency for reliability projects to be easier to justify than economic projects.

Then again, even if you do that, you still have to identify beneficiaries, and again, I strongly believe that you have to assign costs to beneficiaries.

Again, the beneficiaries will have to agree to pay for those costs, too. Because the other thing is that because of circumstances, changes, and uncertainties in the system, the benefits can completely flip, but you still have somebody making a commitment that you are going to pay for that.

So that comes from somebody saying that that transmission solution, or whatever solution it is, is going to address the future, or the scenario that they are planning for.

Question 4: I do agree with the point that those who make money from a new transmission line, like for instance wind generators, should be assigned some of the cost.

The question I have for you all is this. Speaker 1 was talking about transmission planning and how we should look well beyond the 10 year time horizon, which I completely agree with.

I want to know if anybody's factoring in extreme weather like Sandy and other things like that, as well as cyber terrorism and cyber security.

A lot of large customers and small customers, especially in the New York/New Jersey area, are starting to do microgrids. More and more are combined heat and power and microgrids and islanding, as number of facilities did during Sandy quite successfully, and the word is getting around.

My concern is, is anybody in transmission planning factoring in the I think rush from the distribution lines and grid systems in the sense of being able to island, and, like Princeton, having their own combined heat and power facility where they're doing a lot of the base load generation, which will therefore require much less electricity being sent over transmission lines.

My concern is stranded costs for new transmission lines now, because I believe there's going to be more extreme weather. There's going to be more cyber security and terrorism issues. Businesses want to be able to get offline and keep functioning.

I'm very concerned that ratepayers are going to be stuck with stranded transmission costs where these lines are being put in in the near future.

Speaker 3: I'll start with that one. First I'll say that issues like cyber security or physical security or storm hardening are absolutely things that the utilities are looking at, in terms of making the right kinds of investments or mechanisms on their transmission and distribution systems to bolster their system.

Often those types of enhancements are not really the kind of capacity additions that transmission planning often looks at, so it's not usually a focus of regional transmission processes. It's absolutely a focus of utilities as they're doing their asset maintenance in upgrade work.

As it regards microgrids, this is a new area, where customers or groups of customers are looking at microgrids and looking at serving their needs with distributed generation and distributed resources.

So, for National Grid, for instance, the city of Northampton in Massachusetts and Clarkson in New York, these are places where microgrids are being played with and developed.

One of the things that we're going to learn from this is whether a microgrid is really completely separate from a system. Or is this really about folks adding in generation to reduce the generation that take out of the system? Do they still need the system for either back-up power or the ability to sell power out or to take power? So I think what we're going to see is that either microgrids or customers are still relying on the delivery system, but they're using it in a different way than they did before.

So we have to make sure that we're pricing the service of delivery systems correctly. It would be different than what we do today, which is based usually on energy usage only, and it's not really reflecting what the delivery service brings to the customer who is using distributed generation resources. I just think it's a big space of evolution for us, but I think it's tied to ultimately rate design and how we value the delivery services of the grid.

Speaker 2: I think this is again a very, very important question. As you have more and more distributed generation, what it does is that it primarily impacts your load forecast, what you are planning for.

Since Hurricane Sandy and others, there is a big initiative for the New York PSC related to this. It’s the number one initiative right now.

I’ll give you an example of what we do for energy efficiency, which has been going on for a few years. New York State has very ambitious targets for energy efficiency. We as an ISO independently verify and make our own projections, which may not be identical to the state targets. We have conversations with the PSC, but we see what the track record is year to year and then we make our own projections.

If they say 20%, we might say that, “Look, we see 10% coming.” And we plan our system based on that. Something similar might evolve out of microgrids.

The only issue with microgrids is that they're very dynamic. So not only do you have to forecast the peak, you have forecast what's happening during different times of the load cycle. Almost every five minutes. So load forecasting becomes difficult. Planning becomes more difficult.

Speaker 1: That's really where probabilistic planning can maybe help, but when I hear you say, “Oh, we're going to have stranded costs,” I'm thinking, we're not going to have a robust enough system, because it's not a one-way flow. So now you've go the system doing this two-way flow 24/7 with people selling on to the system and putting energy on to the system, taking energy off, so instead of having a 0 to 1,000, or 0 to 300 megawatt load there, you've got a -300 to +300 megawatt load. That just means you might need a more robust transmission system, as opposed to less transmission.

Questioner: In that regard, though, what Princeton and others are doing with the combined heat and power facilities is base generation. What Princeton does is they play it off. So, if Public Service Electric and Gas is cheaper, they'll take it from them. If doing their combined heat and power is cheaper, they take the combined heat and power, but that is almost continually operating.

So they're not really selling power back into the system (even though they do have solar). They're really using it for their own operations.

I understand the issues with solar and all that, but with combined heat and power and microgrids… I mean, my personal preferences? That's the way to go and I think a lot of smart people are going to be doing that.

Speaker 1: It really depends on how the microgrids are designed, because some are designed to be really buying and selling according to what's going on in the marketplace. The issue is still you're going to get huge amount of variability.

So, as a transmission planner who is going to get fined $1 million a day if you don't plan correctly, you're going to be looking at the highest net load that you get during the course of the year and at the peak hours. And sometimes it may be causing problems at off-peak hours as opposed to at the traditional time.

Speaker 4: I find your question actually really interesting because when you first start talking about Superstorm Sandy I thought you were going to be asking about these high impact low probability events, and how do you account for them when you look at the benefits or the potential costs, and I thought I was going to reiterate the fact that we do need to look at the potential insurance value associated with these projects relative to those high impact low probability events.

But then you said, “Well, but I'm worried about stranded costs, because if we built those projects because we're worried about those high impact low probability events, we might end up stranding the assets.”

I agree with Speaker 3. I think we're still learning about what the microgrids can really do. Do microgrids really just want to completely separate themselves during these high impact events, or do they need that insurance? Because if they need that insurance, and the grid in general needs that insurance, that project actually can skyrocket in its value just during that event.

Questioner: Last year I heard someone say in a closed session that he thinks the future of the electric companies and the distribution grid system is this is a back-up battery to the combined heat and power of the local generation.

This is a major utilities vice president who handles this stuff, and he said that a year ago, after Sandy and because of also the New York Times story on cyber security and all that.

It might be infrequent, but Sandy was a 500-year storm and Irene a year before was a 100-year storm, so they're becoming more frequent.

Question 5: Thank you. I have a two-part question, and it also has to do with distributed resources.

In California there's an awful lot of interest in nonconventional alternatives to transmission, and especially reliability projects where we can identify preferred resources, like energy efficiency, demand response, renewable DG, instead of building a transmission upgrade.

Now, with the separation of responsibilities in an ISO area, the ISO is responsible and has authority in transmission planning and getting transmission built. But the public utilities commission is responsible for resource procurement.

So we may recommend to our board to defer a particular reliability upgrade, based on our analysis that says that a particular bundle of preferred resources would actually be a better choice because we believe it's more cost effective. But then we have no authority to see that that bundle of resources actually gets built. How do we track it? These are things we're trying to think about--how do we actually track a project to see that it's happening in time, so that at a certain point, if need be, we can fall back to the transmission upgrade if it looks like the preferred resources aren't going to come online.

So I'm wondering whether you are facing similar problems. How have you seen this kind of question being addressed in other areas?

I'd also like to add on to the previous question raised. Rather than just stranded costs, what about the impact on transmission access charges if the megawatt volume crossing the transmission grid substantially declines due to distributed resources? We could be planning and/or building transmission upgrades, but now the denominator on which we recover those costs is a shrinking number. We can't just plan for load growth anymore. And again, what do you see? How is that being addressed as folks are looking at transmission planning these days?

Speaker 3: I did mention to the previous questioner that, similar to California, New York has targets (for energy efficiency, etc.). We independently verify those targets, and we might come with a projection which is not aligned with the target. OK?

So they might say the target is 30 and we might say it's 20. Or they might say target is 20, 20% penetration, and we say what we observe from in terms of penetration is more likely to be 15%.

So we can plan based on our independent assessment of the state initiative.

Questioner: So, New York ISO actually has the capability to do that research as to how these resources are developing and making your own projections?

Speaker 3: Yes, and we've done that primarily for energy efficiency. In terms of the potential for stranded assets, yes. There is a potential if distributed generation comes and has significant penetration.

It can be over the next 30 years. People talk about having a “Kodak moment” for the electric industry when the efficiencies of behind the meter generation are going to be more attractive than central station engineering. It's conceivable in the next 30 years we might have a Kodak moment, but if you build a whole bunch of transmission for that, you will have stranded assets.

The fact is and we all recognize that when you calculate beneficiaries, it's based on an expected future. But the proof of the pudding is whether one set of beneficiaries is willing to pay hard cash based on their belief in the future.

So it is not sufficient to identify beneficiaries and assign cost to them. It has to be a voluntary and a proactive financial commitment, based on the beneficiaries' belief in that future.

That's kind of the hard economics of it, but reality may be less clear.

Speaker 4: I guess I just want to add that I think you bring up a really good point about the megawatt hour decline. It doesn't just apply to transmission costs, right? It applies to distribution. It applies to generation. It applies to environmental upgrade costs--the entire cost, especially fixed costs, associated with producing and delivery of the power.

I mean, there's probably every day an article about the utility business model and how distributed generation and other factors are affecting that. I don't think we can get away from that. I actually think, personally, that rate design can only get us so far. We talked about, "Well, maybe our traditional way of allocating costs per megawatt hour is not the right thing. Maybe the fixed costs need to be allocated…" I think those things can only go so far. As soon as those distributed generation resources, or maybe battery resources, or customer located resources, become cheap enough, customers are going to make those choices.

So we do need to think carefully about the choices to the customers because it is an economic choice at the end of the day. So I do think that's a concern.

Speaker 1: But as we discussed this morning, we've bundled together this cost for consumers in terms of kilowatt hours, when in fact there are a lot of different products underneath that that make up the system that keeps their lights on.

If someone wants to put in a microgrid and put in battery storage and go off the grid, that's great. But if they still want to have the grid as backup, they need to pay something.

As Speaker 4 said, our rate structures aren't set up for that right now. We don't really understand how that should impact them and how it should impact the planning. So I just don't think that we should jump to the conclusion that we're going to have stranded assets, because they're still going to need things for backup power. And they're going to be using the system differently.

What we need to do is start thinking about those uncertainties and saying, "OK, our planning models are not equipped to deal with this. What are we going to do about that?"

Comment: It sounds like you're sort of suggesting almost a revenue model for the utilities that's based on reliability services or some sort of distribution services apart from the kilowatt hours and megawatt hours.

Speaker 1: Yes.

Question 6: Who pays for the transmission? In a state like California, where we have an RPS, the reality is that customers are supposed to be buying the renewable resources. These resources are generally not in load centers so they generally require transmission.

So, one way or the other, the ultimate customer is going to end up picking that cost up, either for new renewables near the load, or for the cost of building transmission.

[LAUGHTER]

Question 7: Thank you. I guess my question is, now that transmission projects are getting away from being more reliability based and moving to being more inclusive of other benefits, such as the societal benefits and particularly the economic benefits, I think that as a regulator it makes the decision-making process that much more difficult.

I mean when it comes to reliability, we know, “OK, the lights are going to go off. We can't have that.” When it comes to economic benefits, we are somewhat taking the utility and the RTO's word for the fact that, “OK, there are going to be these great economic benefits.”

But at some point it's kind of like, “But will there really be?” I mean you're saying this, and, yes, we get a record and we see testimony from a million people, but at the end of the day, it's not like the lights will go off.

So I guess my question would be, what type of a lens should we as regulators be wearing to ensure that we're making a fair decision and at the same time making one that's necessary?

Speaker 1: That’s an excellent question, and one of the really important things that we didn't have time to talk about today, is that as we're going through this analysis, as we're looking at all these benefits, you really have to have all the stakeholders at the table from day one.

That includes the commissions and their staffs to really understand what it is we're doing--because you're right. To come in and say, “Hey, we're going to a produce a billion dollars' worth of benefits out of this line over the course of its lifetime….” I mean, you have to build your credibility and you have to work with people and make sure they understand what is that you're calculating and how you're calculating it.

One of the great things about looking at a range of futures is that everybody can see their perceived world in that range of futures. So they can see how your project will perform. When we did our first economic project we had about six or seven futures. In one of those futures the project did not pay for itself. The load growth was really low, and everything was low, and it covered some of its costs, but not all of its costs.

The folks who really believed that that was the vision of the future, they said, “Well, I see that it doesn't pay for itself in my future, but I also see all these other futures where it does.” So they said, “I'm comfortable with you guys going ahead with this.” So, I mean there's a level of trust, but also you have to build that trust by bringing people along and making sure they understand what analysis you're doing and they have a lot of input into it.

Speaker 4: Yes. The Moderator started this conversation by saying, “Well, as a commissioner I only see one project at a time. I don't see enough of the bigger picture.” I think that's what we're trying to convey.

And I think what we're trying to say is that through discussions like today, we would like regulators to have a broader scope and longer term vision. And perhaps stakeholder communication and education is part of that process, so that you don't only see one project at a time, so that when that project comes to you, you actually understand what the need of the state or the need of the region is and what the tradeoffs are when we talk about alternatives to transmission and what the longer-term needs are. Not just the reliability--keeping the lights on—but, what is the region's growth look like? Right now we're doing some work in Texas and there is potential growth in some areas there that are quite large compared to the rest of North America.

I mean, I think the scenarios in the future that Speaker 1 talked about are important and just as important for planners as they are for the regulators.

So, hopefully, you go away from this not just thinking, “Oh, gosh, I just need to read the testimonies and understand the tables and the calculations,” but really get a broader scope and the longer horizon and understanding of the regional needs.

Question 8: I actually posed a question during break and it was suggested that I pose it to the group, so that's why my card is up.

This is about the new planning framework. Speaker 1 and Speaker 4 both sort of touched different aspects of it. I actually agree with a lot of it. Looking out longer. Broader benefits. Looking at the whole picture. Maybe not project by project. Scenario based.

These are actually concepts that have been around for a bit. I agree that it's sort of looks like you'd end up with a better total solution if we did it that way.

But my question was with regard to Order 1000, and whether or not Order 1000’s new rules enable this planning framework you're thinking about? Or do they disable it or is it sort of neutral?

That's the question I posed during break and I was thinking that Speaker 1 and Speaker 4 might have views on it, because they probably thought about it, or folks might have some views on it.

But that was my question. How does Order 1000 impact new transmission planning frameworks?

Speaker 1: I am very concerned about the impact of Order 1000 on the ability to build transmission. When you look at Order 890, economic planning was mandated, but it's really not getting done. You've heard people say nothing's been built. Very few projects have been built.

When you look at the public policy, people are just starting to learn and even think about, how do I plan for public policy? MISO did a really good job back in the 2009 to 2012 time frame working that through.

You've got your interregional planning, but now you've introduced this competition. And the competition is what all of the RTOs are focused on. It's going to take a whole lot of their time and attention, and you've really kind of created an incentive, because you have only some of the projects go out for competition, go out for bid. But those projects are going to be the bigger, strategic projects, the ones that add the most value.

So my bosses are going to say to me, “Don't bother spending hundreds of thousands of dollars developing all this analysis and finding a project like that, because then 27 people are going to come in and bid on that project. And what is the chance that we're actually going to get it?”

So there's sort of a perverse incentive here for transmission owners to just sort of retreat back to fix the local system, and do reliability-only projects, because you know that those are yours. You don't have to fight with anybody over them.

I'm concerned that this larger, more beneficial build-out is going to get very much slowed down with the competition. And there’s the fact that the RTOs and the ISOs, they don't really have incentives to plan interregionally, and they're all really worried about this competition thing. And we're really working hard on it.

Speaker 4: I agree with some of those things, but I think I have a more optimistic view of this, which is that at least Order 1000 brought some of these concerns you probably had for years to the foreground. At least we bring this to the foreground and talk about it.

On the interregional planning--we've known that projects are not getting planned or built, but at least now, hopefully, it's on the table, so that we can actually, hopefully. address it.

But I do have similar concern about the surprising, probably unintended, consequence of introducing competition at the project level, especially if it focuses on large projects and the rules basically allow for the smaller projects to be within the incumbents, and then the larger projects to be subject to competition.

And this creates this strange incentive that Speaker 1 talked about. I do think that is an unintended consequence, but it could be quite serious, and actually sort of make us go backwards as opposed to forward.

Speaker 1: I will agree with Speaker 4. Just bringing up the themes and things, that's a step forward.

Speaker 2: Let me just maybe give the ISO view. We believe that FERC Order 1000 certainly broadens the scope of the planning process for the ISOs. It includes items and attributes which are just not the pure economics of it, which I think are the things that you were alluding to.

However, you have to realize that FERC Order 1000 also refers to the beneficiaries. But one of the things that I've always said is that beneficiaries should be willing to pay for the benefits. That's the final test.

This whole question of the transmission being an enabler doesn't really work in the transmission text. I mean I talked about how transmission investments are lumpy and they disrupt markets.

And unless you have the cost benefits and have a set of beneficiaries who are willing to pay, you assign that risk on behalf of the load, who is the ultimate payer of the bill. And you take the risk, which is exactly where we were before competitive markets.

So someone has to pony up and say, “I'm going to pay for this.”

But then you have the other track of, “Transmission is good, let's copperplate the system.” And if you look at what's happening with DR, what's happening with other things, you just don't know what the benefits are.

My boss, who came from TVA, says that transmission is often the no regret solution, because it's the most versatile, because instead of having a targeted power plant where you need it, you don't know where your system may shift.

He talks about how TVA built the robust connection with Georgia and other places to sell the low cost hydro from TVA. But he didn't realize that no one in TVA anticipated that NRC was going to shut down all the nuclear power plants. The only reason they could survive that was because they had a robust transmission system.

So there are lots of benefits to transmission, but you still have to do the long range planning. You have to look at these disruptive lumpy investments and you have to have beneficiaries assigned. And hopefully the beneficiaries will agree to pay for it. Otherwise you are taking the risk on behalf of beneficiaries, and on behalf of the demand, which is ultimately the captive rate payer, basically.

Question 9: I just want to retrogress back to the earlier comment that a generator is the equivalent of transmission upgrade.

I'm not sure I agree with that, but let's assume that it's true. If that's true, then a demand response resource is a substitute for a generator, and what you basically have here is a low capital peaker with a high running cost. It gives you a lot of optionality without having to invest much, so the stranded cost issue goes away.

Now, going back to my doubts about this, transmission flows are very complicated. If you look at just a static situation, yes, you can put a generator somewhere that will give you the equivalent of that transmission upgrade. But the thing is that where the flows go in the system and what gets congested when depends on what generators are out of commission, what the loads are and how they're distributed, what lines are out…

So you have a huge number of permutations here of what can happen. If you wanted to get the equivalent of that transmission upgrade, you might have to put in generators at multiple locations in the system.

Speaker 4: It's precisely that. And also, speaker 2, you spoke about having beneficiaries pay, but you also talked about the evolution of the beneficiaries. Because if we look back to the transmission we built, we will say that the benefits were not static, right?

We could build a CREZ line, for example, to western Texas. Are the beneficiaries wind? Well, maybe now the line is not just used for that, right?

When do we say who the beneficiaries are? I'm not saying it's impossible. I'm also not saying don't identify the beneficiaries. But let's recognize that the beneficiaries can evolve over time. It's just not that black and white.

Speaker 2: Yes, and I think it's more important that somebody ponies up and puts their own capital at risk, which is what generators do when they're building, instead of having this approach of, “identify benefits and then pancake it”--give it to the demand to pay for over 30 years.

And to the issue raised in Question 9, demand response is a valid option. That's one of the reasons we do “all resources” planning and not a transmission plan in New York.

Question 10: Are natural gas pipelines part of the transmission planning framework, particularly with the issues that we've seen up in ISO New England area and PJM and NYISO this year?

Speaker 3: There's obviously a linkage between the gas sector and the electric sector. We're seeing it play out in New England.

I also think that the New England states, which are considering increasing gas pipeline and also considering electric transmission, are kind of recognizing that how much gas you put in impacts your gas usage and therefore what your electric generators are doing and whether or not you need new transmission from new places.

And vice versa, if you put in new transmission that's bringing hydro and wind down and replaces some need or demand from the gas generation, that impacts how much gas pipeline you need.

So I don't see it as strictly a piece of transmission planning. I see it definitely in the purview of the ISOs to consider what are the major constraints and contingencies that impact electric reliability. As we can see, in New England gas pipeline constraints is one aspect of that.

Speaker 4: I think you bring up a very good question, and New England is probably at least one of the regions where that's really coming to a head, because we are lacking gas infrastructure.

We're also arguably lacking transmission infrastructure, and the play-off between the economics of where the gas generators are and the availability of the pipeline and whether transmission can cross over--I don't think we're there yet.

I think we're just beginning to talk about things like that. If we had an integrated resource plan for the region, we would probably need to think harder about that.

So basically we're attempting to have an integrated resource plan for a region where you have a completely competitive market, so it's quite challenging. But I think bringing those topics to the forefront is a start.

Speaker 2: Again, I think it's important, as was stated several times this morning, that you have to get the prices right. If the prices are right, then private entities can make the tradeoff.

Just to give you the New England point of view. New England ISO started with one clearing price for all of New England. So all the generators located in Maine and western Massachusetts. There was a lot of transmission to be built to get that to the load centers.

Today New England has LMP, and people have the price signals of whether you're going to build a gas pipeline or the transmission line.

But the fact is that in New York there was LMP, and all the generation located near the load centers in New York and New York City. It also is easier to build a gas pipeline and a power plant in terms of permitting and siting than to build a transmission line.

Transmission lines face bigger hurdles. That's a fact. But where there are price differences, transmission lines have been built. There's a lot of high prices in Long Island, so transmission lines have been built from New England, from Connecticut, which is a high price region in New England, to higher price regions in New York. And the same from New Jersey to New York.

So I think to get the price right can have people make the correct choices, and you don't have to do integrated resource planning between gas and electricity.

Question 11: I just wanted to respond to Speaker 2's statement that it's important to have the beneficiaries buy into this whole rubric. I agree very strongly with that.

My question for the panel is, in a world where you're allocating costs now on a very broad brush basis, and you're going to consider very long term, wide ranging societal views--we're talking about public policy lines, not just reliability lines. And you're going to allocate them to people who do not have the ability to pass those costs on to rate base, is the ISO, which is really not in a position to bear any of the costs, is the stakeholder process in a multi-state ISO really best designed to make sure that everybody's voice gets heard?

Speaker 1: I don't know that it's the best design, but I don't know that we have anything better right now. At least in my experiences with MISO, folks get in there and they talk about the scenarios and they talk about the analysis.

You have to have some political will behind that kind of process, and you have to have some agreement that we're going to make this decision and then we're going to allocate these costs and that's going to be acceptable. And that it's got to be acceptable.

When I hear Speaker 2 say to get buy-in from the beneficiaries, I'm thinking, like, each specific person. But really that plays out in different ways in different ISOs. In MISO's case, it was the governors coming together and saying, "Look, we know we need a more regional system, so you go plan one for us and we'll agree to let you spread the costs across all of the folks."

It just depends, I guess, on how you define beneficiaries and who gets to make that decision.

Speaker 3: I would say, coming from a multistate region, the ISO process (again I don't know if it's the most perfect thing in the world)--but the independence of the ISO obviously lends an element of credibility, if you will.

There's an open and transparent process. There's the fact that all the sectors are in there. State engagement is super important as well. And I think just the dialogue of going through changes and having people form their analysis and opinions oftentimes helps to lead to a decision.

Usually it's not something that everyone agrees with. You know, there's going to be entities contesting it at FERC, or whatever, but it is a process that does in many ways work and get to a decision at the end of the day.

Speaker 4: I guess my only comment is that to date most of the costs of the transmission system have been borne by the rate base. That's a pretty broad base and pretty wide spreading of the cost.

If you're going to impose costs on very different groups of beneficiaries, such as wind generators or demand response, I think it may not work as well as it has in the past.

Speaker 1: I just want to comment that I'm a little confused when people say, "Well, the transmission is broad based. It's paid for by the load and therefore we need rules, but we want to restrict the transmission we build because it's paid for by everyone."

Load ultimately pays for all of it because if they don't the generators go out of business. So, ultimately the load is paying one way or another. It's a question of whether they're paying through the increased cost that the generators have to have in order to build the generation and the transmission. Or they're paying for somebody else to build the transmission.

So I find it a little bit challenging to think in terms of, "We're going to make rules now because we don't want them to pay broadly," because ultimately the load pays for it all.

Speaker 2: Yes. I think the important thing here is that the load ultimately pays for it all, but it depends on whether the load is take the risk of an investment decision, which is large, and is there a better way to have gone?

If the load takes the risk--it could be a representative of the load, like the transmission owners, the load serving entity, taking that hedge or risk or long-term commitment on behalf of the load. It shouldn't be based on a regulated entity and foisted on the load. You take the risk on behalf of the load.

Speaker 4: Just also be careful, though, when you say they're taking the risk of building the transmission. If you don't build it, in some cases, you're also facing the risk of paying higher costs of power to the load. So it is a balancing act and there are two sides to the coin.

Question 12: Here's what I'm struggling with. Speaker 2 told us earlier the economic evaluation process in New York probably has been on the books for 10 years and has not resulted in a single economic project getting built.

We just looked at PJM and MISO IPSAC (Interregional Planning Stakeholder Advisory Committee), the interregional planning process. Seventy-five projects were proposed for market participants who thought those were really good projects.

It all goes through the evaluation process. One project passed the joint test, and that project would fail the MISO test. So I'm wondering, are there no economic projects?

Are we understating benefits, or are we setting up evaluation criteria that are just set up to fail?

If there are economic projects and the tests fail to identify them, what should we do about this? Is Order 1000 working or is it not working? Or are people just paying lip service to all of this?

Speaker 2: I just need to correct one aspect of this. Yes, I did mention that in New York we haven't built a single project based on FERC Order 890. But it hasn't been in the books for 10 years.

I believe this is the third year we're going through the economic planning project process. We rejected a couple of projects. We haven't had one based on that.

But in New York we have several projects we've built. Because if you give the price is rights, project will be built.

There's a cable from Connecticut to Long Island. From Neptune from New Jersey to Long Island. There's the HTP (Hudson Transmission Partners line) from New Jersey to New York City. There are a number of projects which have been built.

In the economic planning process, there are projects in the queue. Again, we expect projects. If they are viable projects they will be built.

But I do agree it's harder. It's more difficult to do an economic project than to do a reliability project, because everyone says that if it's a reliability project, it's going to be built because you need it for reliability. But when there are clear economics--clear price difference in LMPs--economic projects have been built, and I'm confident they will be built based on the processes we have.

Questioner: Just to clarify, these are not projects that were built under the ISO tariff? These are merchant lines that were built between markets, right?

Speaker 2: Yes, it was not built under our 890 tariff process--this is only our third year we are going through it.

Speaker 1: I would say we're not counting all the benefits appropriately in those instances. Maybe all of those projects shouldn't pass, but the economic tests are really restrictive.

When we look at a line that we're building as part of the Badger Coulee project, the adjusted production costs or the ATC customer benefit metric was a pretty small portion of the total savings.

The avoided reliability costs, the renewable investment benefit…there were a whole slew of other savings that were very significant. If you just looked at production costs, we would never be building that line.

Question 13: I just wanted to go back to some of the earlier comments or statements that it may not be worthwhile to develop the really big projects, because you are going to have to compete for them.

There are other models that would allow you to keep the proprietary rights of the projects that you develop and have a sealed bid process and let the ISO evaluate which ones actually win.

So there are other auction models that allow you to keep the value of the projects you develop.

I think your position would be, we're going to develop the project and then they're going to put it out for bid. That's probably not the best model.

Speaker 1: But that is the model they're using. Yes. I completely agree with you. [LAUGHTER]

Questioner: My suggestion is, change it.

Session Three.
Distributed Generation: Alternative Ways of Pricing the Output and Dealing with the "Lost Revenue" and Cross-Subsidy Issues

Distributed Generation (DG) in most U.S. jurisdictions, historically, was a marginal issue that was largely addressed by the simple, straightforward method of net metering. DG owners would pay nothing to the utility when they were consuming their own output and would be credited at the full retail price for any excess they exported to the system. While one could argue the merits of the methodology, the small volumes were insignificant. With the increased demand for renewables, largely motivated by carbon concerns, and the rise of a large scale DG solar industry substantially stimulated by subsidies like net metering, the issues associated with DG are no longer marginal. While the solar industry and many environmentalists are largely satisfied with the status quo, utilities are complaining about revenues needed to support the distribution network being diluted, low income groups are unhappy with what they see as a shift of costs to them from higher income consumers, many economists are concerned about "out of market" pricing, and utility scale generators complain about discriminatory pricing that puts them at a commercial disadvantage. The increasingly widespread use of smart meters enables that debate to be far richer than might have been possible just a few years ago. Among the alternatives are feed-in tariffs of various sorts, reallocating distribution costs with more emphasis on fixed rather than variable costs, paying the LMP for excess generation being exported into the system, charging DG customers for all the energy being consumed and then crediting them for what they self-generate (at LMP or some other level), and utilizing auctions of various sorts to set a market driven price. As the debate over how to deal with DG heats up, what methodologies ought to be on the table for serious consideration and implementation?

Speaker 1.

Thank you. I want to make it clear that the weather today was not arranged in order to prove that solar is not reliable. [LAUGHTER] I would like to claim I did it, but that would not be credible.

I want to start with a look at the value propositions surrounding solar in terms of five categories, and then talk about a couple of options for pricing.

The value propositions I want to talk about are energy capacity, externalities, reliability, hedge value, and transmission. Because these are often cited (sometimes jobs are cited, but I didn't want to get into that) as the basis on which we should price distributed solar energy products.

So let's talk first about energy and capacity. Obviously, solar energy is intermittent. And the value with the energy is the value of what that energy is at the time that it's produced. And obviously that varies. And whether or not it's coincidental with peak demand varies widely, depending what the peak demand is, but in some places, it's not.

So the energy value is diminished, and particularly if you have LMP markets that are time sensitive, then anything that's not coincident with peak is an energy value that's less than it might otherwise be. And if it's not coincident with peak, its capacity value is negligible. There may be some, there may not be. But the point is that what the real value is, is the energy produced, in terms of energy and capacity, and when it's produced, and how that squares with what's going on in the marketplace.

The other possibility, of course, is that you can have an adverse impact on wholesale market prices if you've got subsidies for DG that essentially distort that. And of course, the assumption I'm making in order to get into distortion is that DG reaches a critical mass, which in many places it doesn't, where it can really have an effect on the price.

But the point is, it's not like you're installing the capacity, and therefore you can add this to your bank of capacity you need when it's there. Now, the thing that would change all this, of course, is if it was linked to storage. If you link it to storage, than the values change. It becomes much more valuable; both from an energy point of view, and perhaps from a capacity point of view, it becomes a much more valuable product. But with that in the absence of storage, it's not.

And if you use net metering, then essentially, what you're doing, is you are providing, apart from all the tax-oriented subsidies, and the RECs markets, you're adding another subsidy, basically throwing in some distribution cost, to further subsidize distributed energy. And the value isn't there. So, net metering actually tends to inflate the value of DG to a point that it really is not justified.

And you know, the interesting thing about net metering, of course, and we've talked about this in the past at HEPG, is that it's really a feature of outdated technology. We didn't have a lot of choice in the era of dumb meters. And net metering worked.

And we no longer have dumb meters, and we can do more intelligent things, at least where smart meters are deployed, and the question of how we've done this in net metering doesn't make a lot of sense. And when you look at the energy and capacity value, and particularly the energy value, of solar, you can price it on a much more intelligent basis. But I'll talk a little bit more about that in a minute.

The issue, of course, is where the romance with solar energy comes from. (And I'm only talking about DG. Most of what I have to say only relates tangentially to utility-scale, or large-scale, I don't mean utility owned, but utility scale renewable projects. The issues are very different in regard to them.) But the romance is, PV units produce zero emissions. And this is the classic case of cherry picking your data. Is that statement true? Yes, it's true. If you look at simply the production of energy, it produces energy with zero emissions. However, where are 75% of the solar panels used in the United States produced? They are produced in China, which produces them with, of course, their secret formula for the cleanest of energy.

And so, if you follow the production cycle all the way through the impact on dispatch, and we talked about that in Tucson at the last HEPG, particularly because of what's happening in Europe, it doesn't produce zero emissions. Not if you go through the entire process. And the only intellectually respectable way to look at this is to not just look at whether it produces emissions when it's actually producing energy, but look at the entire cycle of production through impact on dispatch, and the answer is not zero emissions.

Now, I'm not saying that it may not have an environmental value. It may. I mean, it's an empirical question, and you have to analyze it. But you can't simply assume there is an environmental externality value without looking at the entire cycle. So, for anything that focuses just on whether solar PV emits in producing energy, I think that is cherry picking the data.

There's also a notion that if you promote solar, you will be reducing emissions. And I think people get renewable energy confused with reducing carbon emissions, and they are not the same thing. I mean, solar DG may or may not contribute to reducing emissions, and certainly the German experience raises questions about whether it does, but it may or may not. I mean, it depends on circumstances.

But the simple fact that you are promoting renewables doesn't mean you're necessarily reducing emissions. If you want to reduce emissions, then set carbon standards. That's the way to do it, as opposed to trying to do it through all these roundabout ways which don't necessarily get you to where you think you're going.

But the other interesting thing is, what's the impact, particularly in regard to net metering, on energy efficiency programs? As we've talked about in the past, when utilities are looking at the loss of distribution revenue from net metering, one of the ways they try to protect themselves is to put more emphasis on fixed costs, because after all, distribution costs are generally fixed. So they put more emphasis on that, which many economists would argue is the correct price signal. Many environmentalists would argue the opposite. The more volumetrically based the price signal, the better it is in terms of signaling to people to be more efficient.

But if you have a policy of pricing DG in a way that further reduces distribution revenues for utilities, even though the solar DG providers provide absolutely no distribution benefits, and you want to make distribution charges non-bypassable, how do you do that? You make more and more of those costs fixed. Which, as I said, from many economists' point of view, is the right thing to do. Many environmentalists would have strokes over that idea, because they want things volumetrically based.

So you may be substituting a so-called green technology for so-called green pricing. And there's kind of a trade-off involved. This actually is particularly ironic. I was talking to somebody recently who, on his utility bills, buys a lot of RECs, and most of those RECs go into large-scale wind and solar units, and his point to me was, "Why in the world, if I'm putting money into more efficient units (and after all I think there's a general consensus that large-scale renewable technology is more efficient, it's more cost-effective, than small-scale, than distributed scale) why should I be putting money in RECs, and after I put that money in RECs that are going to more efficient technology, you're now asking me to subsidize something that's less efficient and produces less green value than the other?" And it's an interesting question, because it does have kind of a perverse effect.

The other externality to consider is social externality. There is no question, and I think the studies in California and actually the Arizona commission staff sort of noted this in passing in their report on the APS case, it really amounts to a subsidy from less affluent customers to more affluent customers. And so, as somebody put it, it's kind of "robbing the hood," as opposed to Robin Hood[LAUGHTER].

So it really is a subsidy that's socially regressive in its effect. And you know, somebody once argued with me, saying "No, no, that's actually not true, because poor people can have solar units." Most poor people rent, they don't own, and the likelihood, if they owned, that they're going to be spending more money to put solar units on their homes is almost non-existent. So from a social externality point of view, it's regressive.

Reliability. First up, any distributed solar exported through the distribution system is subject to exactly the same risks as any other generation. If the distribution system goes down, solar reliability to any other customer, other than the solar host, doesn't exist.

Now, maybe in a micro grid, it might exist, but 90% of outages in the U.S. are distribution related. And solar is not immune to distribution.

Now, it may provide a value to the solar host, but that's an individualized value. It's not a case for having the system subsidize it, but there may be some additional value to the solar host, and that may be a good reason why they'd want to invest in it, but the reliability of solar for the system as a whole is no greater than it is for any other form of generation. It's still subject to distribution problems.

Beyond that, if solar isn't linked to storage, then its value is substantially diminished from a liability standpoint as well. I mean, for example, most residential peak is in the early evening, or in some places it's in the morning, but it's not in the middle of day when solar is at peak, in general. There may be exceptions to that. So, in terms of providing reliability when at least residential load needs this the most, it really doesn't add much.

And what's particularly interesting about it is that if solar had storage, it would add a lot more to it. So why would we develop prices that subsidize inefficient use, as opposed to prices that support efficient use, that is, coupling solar DG with storage of various kinds? I mean, there are programs around to link them to electric cars or plug-in hybrids. There are other programs, obviously, with batteries, although everybody knows batteries are still at a somewhat primitive stage of evolution.

But if in fact you get the pricing right, what you're doing is you're stimulating the commercial development of storage, making this a more efficient product. If you don't, you're actually discouraging the evolution of storage. So from a reliability standpoint, the real benefit is if you couple solar DG with storage. If you don't, you lose a lot of the value from the reliability standpoint.

And in fact the irony is that if you use net metering, you're then depriving the distributor of revenues that go into supporting the distribution system, which inevitably will reduce maintenance or reduce investment, and in fact probably will drive down distribution and reliability. So net metering actually produces a result that I would argue makes things more likely to be less reliable than more reliable.

It's also subject to the same distribution disturbances as other generation. If someone has a unit on his house, and I'm his neighbor, and the distribution system goes down, there's no reliability benefit to me. He may have one, or he may not. I mean, I also think if you have hurricane Sandy, the solar panels on the roof aren't going to be any more secure than anything else.

There may be a fuel hedge value. I mean, this is, again, not implicit. You can't assume that for purposes of pricing solar DG. But the value of the fuel hedge is driven, again, by reliability, by availability at peak, and peak defined in this case, both for energy and when we may have congestion on the pipelines, so you have to pay a premium price for access, for pipeline capacity.

So there may be a fuel hedge value. What you can't do is automatically assume that it's there. It depends. It's an empirical, analytical question. And to simply assume it for purposes of setting administrative prices for solar DG, is just simply not going to be accurate. It's not going to reflect the reality. So is there a fuel hedge value? Maybe there is, maybe there isn't. It depends.

Value relative to storage and financial hedges. What's interesting is to the extent to which solar DG is actually subsidized, it may in fact distort the kinds of financial hedge markets that you have, and actually create adverse circumstances. So in terms of looking at its value in the marketplace, in terms of the derivative products, in terms of storage, there are two things to consider.

One is, of course, with storage, as I said, if you simply subsidize inefficient production without linking it to storage, well, you're subsidizing a wasteful use of solar energy. And if you're giving it a hedge value, you may in fact distort the derivative market. So that's another problem.

The other thing is, to capture the system hedge value, what you really need to do is aggregate solar DG. Otherwise whatever hedge value it has is largely individualized. So it may be an argument for an individual to put a solar panel on his roof or her roof, but it's not an argument to simply do it for the system a whole, to subsidize it from the system as a whole.

And I think a lot of times we confuse individual incentives for solar hosts with system benefits. And they're not the same thing. And I think when it comes to actually setting pricing for the system, you need to think pretty carefully about where these benefits go. And in both reliability and even in the hedge value, more of them are captured by the solar host than are available to the system. And so you need to think about the pricing in that context.

Transmission savings. There may be transmission savings. Again, it's an analytical question. You cannot assume that there are transmission savings, but it's possible. If, for example, solar DG is available at the time of maximum congestion, or at high congestion, you may well save on congestion costs. That may well be, and if so, then the solar DG provider should be compensated for that benefit.

Whether it actually long-term reduces the need for transmission capacity is a tricky question. I mean, you can argue about that, but you'd really need a very substantial critical mass to do that, and you'd also need it to be available at times when the system is most likely to be congested and need some additional transmission relief. It is possible, but it's an empirical question. You cannot assume, for purpose of pricing solar DG, that there are transmission savings. It's possible.

If so, then the solar host ought to be compensated. If it's not, then they shouldn't be compensated. But I think in a lot of places, the assumption is, "Oh yeah, there are these transmission savings, we'll just factor that into the price." Well, that may be true, it may not be true. So it's theoretically possible, but not necessarily true.

So where does that leave us, in terms of what the pricing is? Well, my first conclusion, which I didn't put in writing, is that net metering is a bad idea. And I have sort of two options, one of which, the first one, is the one I think is actually the correct one, which is that solar DG customers should be billed for all of their consumption. It doesn't matter whether they sell, produce, or anything else, they pay for all of their consumption. However, for everything that they produce, they get the LMP value at the time they produce it.

So if they produce at peak, they're going to get a higher price. If they produce off peak, they're going to get a lower price, but what they're going to do is they're going to get a price that reflects what the price of buying energy elsewhere is at the time that they're producing it. And you don't have any risk of distribution revenues being lost.

And the key thing to keep in mind here is, there are no distribution savings associated with solar DG. None. There may or may not be transmission savings. There are no distribution savings. Now, it may be that when we go to congestion pricing on distribution systems that will change. But we ain't there, and I think it's going to be a long time before we get there, if we ever get there. So any diminution in contributions to the distribution system is like providing free battery backup to solar hosts. And not only free battery backup, but making other customers pay for it. So it's a cross subsidy that really can't be justified.

Now, again, apart from LMP, should solar hosts be eligible for capacity payments? The answer is, "Maybe." It depends on whether or not they actually contribute to capacity. If they're only available off peak, then the capacity value is negligible if it exists at all. If, on the other hand, they're reliable, and they can produce on peak and reduce your need to purchase in the spot market, or reduce your need to contract to cover peak times, then fine, there's maybe a capacity value and you ought to be compensated for that.

My point is, you can't simply assume that value because you have the nominal capacity. It may or may not have real economic value, and it's an empirical question. That's my own preferred pricing option.

But obviously in a lot of the country we don't have LMP, so you either have to find a proxy for LMP, or the alternative would be, if you're in a state that has an RPS, and the utility is not just about finished in its RPS compliance, or it's got a lot of work to do, one option is to simply to do an all-renewable auction, which includes large scale and small scale renewable, and whatever the market clearing price is in that auction, that's the price paid for solar PV. And that's another way to do it. I think that's a less efficient way to do it, but it may work in contexts where you have an RPS and you don't have LMP.

But these options are designed to really put the solar DG in the full market context of what its actual value is, as opposed to a bunch of administrative determinations about externality value and hedge value. Those are empirical questions that really need to be analyzed in order to come up with real numbers, as opposed to just simply assuming them. Thanks very much.

Question: I have question. You said that long term transmission savings were possible, but improbable, I think. You went on to say that distribution savings will be not possible. And I guess I was thinking that, to the extent that solar reduces traffic on a distribution circuit, maybe there's some savings on the long term. And I would come to the same conclusion that it's in, it's possible, but improbable, for distribution and transmission, but you made a distinction, and I didn't understand that.

Speaker 1: Well, you're right. There is some, I think remote, possibility there could be distribution savings. But those are pretty remote. And if we had more sophisticated distribution pricing that sort of reflected transmission pricing, then I think the savings might be more recognizable. For transmission savings, it really is an empirical question. There may be savings. That could be correct. It may also be incorrect, but you've just got to look at it.

For distribution, it's a little hard to see how that happens. I mean, you're right, if you've got, you know, a critical mass of solar that causes some reconfiguration of the distribution system…actually it could increase costs in distribution. So it's not that it doesn't have any effect, but I think I would argue it's equally probable, and maybe more probable, to increase the cost than decrease the cost. But if you wanted to get very sophisticated and do an empirical analysis, that's fine. I mean, you can do that.

My problem is that in most states, either they use net metering or they make these sort of administrative assumptions about, the value of various assumed benefits. And I don't think there is much basis for making those assumptions. If you have an empirical analysis that supports it, that may well justify something.

But the point is, you know, as a distribution company, you've got certain costs to cover. Look, if somebody's full solar and they disconnect from the system, then they shouldn't have to pay any distribution costs. But as long as they are relying on the system, it's not like you can pull the wires back and save money and then put them back on when they need it. They're there, they're fixed. And that's the basic point.

Question: You were talking about the value of solar if there were storage, and I was just wondering what are the types of storage you have in mind.

Speaker 1: Well, it could include a number of things. Actually, I think, in San Diego, aren't they experimenting with tying electric cars to solar DG units? Electric cars would be an example of that. Any kind of battery would be an example of that. You could have some kind of heat storage that's associated with solar. In fact, there are some new solar units that actually internalize some storage capability into them.

So there are a lot of options for how you would do that. I mean, the question is the economics and whether it is economically justified. My point is, if you want to send a price signal to make solar DG more effective, and I think it would be desirable to do that, then you need to provide some incentive for people to invest in the technology that would make the product more flexible, more available at the time you most need it.

Storage is clearly the key element there. So if you provide a price signal, as LMP would, if you're going to pay more on peak and the solar production itself is off peak, but you can store it and sell it on peak, then clearly the value of that to the system is much greater than if you're just selling the solar output whenever it's produced.

Question: In the last slide where you kind of lay out the options, you said that obviously to the extent you have an LMP market, solar should be compensated at LMP for injecting into the grid. But if you don't have an LMP market, let's say you have a zonal market or some kind of a wholesale market, would that be preferred, as opposed to the RPS construct?

Speaker 1: You know, I'm not sure what the appropriate proxy would be where you don't have LMP. I know for companies like Arizona Public Service, they don't have LMP. But there's two things about it. One is, you could run an LMP model, even if you don't use the LMP prices, and that would give you the number that you would need. Or you'd find some other kind of proxy, I'm not exactly sure what that proxy would be, but something that reflects what the energy value is at the time that the solar energy is actually being produced.

But in terms of overall energy availability, the only thing that distinguishes distributed energy from other energy is whether or not there's transmission savings. And there may be. And the elegance of LMP is that if there're transmission savings, those are reflected in the price. So you automatically capture that. You don't have to worry about trying to figure that out separately. It's there.

So if you don't have LMP, you'd have to come up with some kind of proxy. Or run LMP numbers and then not use them for pricing, but use them only for this kind of pricing as opposed to for actual transmission pricing. I'm not sure why you'd do that, but that might be a more politically satisfactory way of doing it.

Question: You sort of set out your ideal way to charge and pay. Would it be their net consumption that they pay, or would you have them basically send all their solar production out and get paid at the LMP and have to consume? Or would it be their net consumption?

Speaker 1: No, they would pay for all their consumption. Everything. Gross consumption. There is no distinction between whether they're consuming what they produce or whether they're exporting into the system, it's all treated the same, it's just assumed that if they produce it, then it has value. Basically, it's actually simpler, because you're getting rid of all these distinctions that make things more complicated.

And the other thing that it does, which is a benefit to the solar, is get rid of production limits. A lot of places have production limits, in order to protect the utilities against loss of distribution revenues, and the production limits would go away, there would be no justification for them.

Question: You also mentioned about renters as well as low income customers. On Thursday, we had a Low Income Oversight Board meeting in California. And then we did a study of our residential users, and we found that one third of the California residential market is low income.

Of those, two thirds are renters. And one thing that's interesting is, of those renters, only one third are living in multifamily dwellings, and the remaining two thirds are single-family household renters.

So I think that this also gets to addressing how we incorporate solar into a market where you have so many renters, the majority of whom are in single-family households. It's harder to do solar on a multi-family, you know, so how do we incorporate the benefits for the low income communities? And is that possible, given this distribution?

Speaker 1: Well, first of all, that may be somewhat unique to California. I don't know, I mean, obviously with the East Coast, you'd find the numbers would be quite different, in terms of who's living in single-family or multifamily dwellings. You know, it's difficult to sort out, because poor people who are renters have no control over the roof. The landlords are not usually going to be overly anxious to invest that kind of capital. Because how are they going to get paid back? So I don't know how you'd fix that, which ought to make us, as regulators or policymakers, more sensitive to this idea that it's a cross subsidy from less affluent to more affluent customers.

Speaker 2.

Speaker 1's presentation is a hard act to follow. He's already covered about half of what I had in my presentation. I'm going to present a quantitative analysis that uses solar PV here in California as a case study. And hopefully, when you see some of these numbers, there'll be some added value to what Speaker 1 has already presented.

Before I get into it, though, I just want to mention that this work is funded by the Institute for Electric Innovation, which is part of the Edison Foundation in Washington, DC. And they're going to use these results to develop an issue paper that'll be coming out in March. The other thing is that the numbers I have in here are still preliminary. I'm still tweaking them. So they're subject to change. And lastly, this presentation has some editorial changes to it that I ended up putting in in the plane coming up. So the final presentation will be on the Harvard website.

We're talking here about net metering, but in fact, all of the problems and the issues that Speaker 1 brought up are associated with distributed generation in general. All net metering does is add some more icing on the cake. You know, it enhances the results that you get, or makes them worse, whichever way you want to look at them.

Primarily, we're having this problem because our retail tariffs are not truly cost reflective. The way they're designed, they are not reflecting the utilities' marginal costs, and therefore, when somebody reduces their energy consumption, they are not reducing the costs of the utility by how much they're actually reducing their bill. And that's the whole issue.

And because of this, what happens is that the distributed generation customers are avoiding paying for some of grid services costs that are allocated to them under the retail tariffs. And those costs then end up getting shifted to everybody else that doesn't have DG. And as Speaker 1 points out, most of those people that are non-DG are less affluent than those that have DG. About roughly 95% of all the DG in the US is rooftop solar PV. So that's why this is what I looked at.

The CPUC had a study done by E3, a consulting firm, that was done last October, and it confirmed that this shift is taking place from the more affluent to the less affluent.

I took California as an example only because they have this multi-tiered retail rate structure that magnifies the effect that were talking about, and it causes all of this cost shifting.

The particular project looked at is a 4KW rooftop solar facility here in Southern California, zone nine, I'm not sure whether that's in Santa Monica or not, but it's close. I probably should've used Santa Monica. That would've been a good example. And these are the numbers that I used. I used an initial investment of about $3.74 per watt of DC, which is aggressive. I got that off the NREL website and a 20 year economic life.

And I did this analysis for a larger customer, because the same E3 study that the CPUC commissioned revealed that about 52% of all the net metered customers consume between 10,000 and 25,000 kilowatt hours a year, as compared to an average for all the three IOUs of about 6800 kilowatt hours. So you can see that these not only are the affluent but also the large consumers.

So here is the tariff that I used, Southern California Edison's net metered tariff under their residential domestic rate. It's a Schedule D. And you can see that the tiers run from almost 13 cents per kilowatt hour, all the way up to almost 32 cents. And the baseline is 13 KWh per day, which is about 400 kilowatt hours per month in the summer, and about 300 in the winter.

For this particular project, I ran a discounted cash flow analysis to calculate how much value the customer would derive by putting this facility in place. And I did it for three different forms of financing.

The first one is where the customer simply pays cash and finances it himself. The second is where he takes out a ten-year home-equity loan against his house, which allows him to write off the interest on the loan against his personal income taxes. And the third one is where he enters into a contract with a solar leasing company like Solar City. The leasing companies actually offer two kinds of contracts. One is a lease, where you simply lease the equipment, and the other is a PPA, where you pay for the power as it's produced. (There really isn't much difference between these two options in a present value sense, because the leasing company will structure both of these leases such that they get the same profit margin either way. It's only a difference of whether you pay a fixed price every month or whether the price varies month to month depending on what you produce.)

So for the third-party leasing, the PPA is what I assumed. I set the PPA equal to 85% of the average of SCE's top tiered prices and escalated it at 2.9%. This is based on a quote that I got from Solar City several months ago. It's likely that this 85% is negotiable. I suspect that Solar City has some wiggle room, and that the people that sell these contracts can change these numbers in order to close the deal.

Here are the results for the equity financed option. The customer pays for it all cash. And the thing that jumps off the page is how profitable these projects are to this particular customer. The initial investment's around $14,500, but actually he gets back almost $4,500 from the Federal Investment Tax Credit, which means that his net is really only about $10,000. And this produces a present value of $17,000, and that's after he's gotten back his $10,000 investment. So this thing is returning a huge profit and it breaks even in seven years. And after that, all the electricity is free.

For the debt financed option, the numbers are virtually the same, with one line item in there. And that's the tax savings that he gets from the loan. That adds an additional $1,000 in present value. It's not a big amount compared to the total project value, but for a marginal project, it could make the difference between going and no going.

But it does also have two other advantages. One is that it’s a no-money-down proposition. The other thing is that it produces positive cash flows throughout the life of the project, so how can you lose with something like this?

Turning to the solar leasing company, the thing that hits you right off is how much of the project value the company takes for itself. In this case, it’s taking over $14,000 in present value. Now, this of course depends on its pricing it at this 85% level. If it were to reduce to that to, say, 70%, this project would be more profitable to the customer and less so to the leasing company. And I would imagine that as competition comes into this, those PPAs are going to be driven down.

Just before I left the house to come here, I got a flyer in the mail for somebody offering to put solar panels on my roof at 70% of my energy price. And my energy price in Washington, DC is about 14 cents. So, clearly, there’s a lot of fat in these projects.

We have to be fair to the solar company, though, because, first of all, it’s delivering a turnkey project to the customer. And that’s a lot of value. It relieves the customer of having to plan the system, of having to find an installation contractor, and of having to manage that contractor, and of having to deal with the O&M throughout the life of the project. There is a lot of convenience to going with a leasing company. And a lot of people wouldn’t have the competence to be able to carry this thing through. Still, there’s a lot of value that’s being given up in return for that convenience.

And the other thing is that the leasing company has costs that the individual customer doesn’t. You know, it has marketing costs, customer acquisition costs, and typically what the leasing company will do is take these PPAs and bundle them up and sell them off to an investor group. So some of that profit has to be given to the investor group as well.

Anyway, I think Speaker 1 has covered these two points. One is, the cost shifting from the reverse Robin Hood effect. And the second point is what’s come out of this analysis, that most of these subsidies, in California at least, are going to the solar leasing companies, not to the individual homeowners. And in particular, in California, roughly 75% to 80% of the new facilities going in are going through these leasing companies, at least that’s what Solar City claims.

And as Speaker 1 pointed out, these rooftop solar facilities are not the cheapest way to produce renewable energy, because utility scale projects are much cheaper.

OK, so how can we fix this? Well, I came up with two regulatory solutions. One, the obvious one, is that if this problem is being caused by the retail rates not being cost reflective, let’s make them cost reflective. So rate design is one way you can do it.

The second is what Speaker 1 pointed out, and that’s a separate buy-sell arrangement, where the customer has to buy all of his consumption under his existing retail rate, and then he’s separately paid for what he produces with the solar facility. And in fact the city of Austin, Texas, has adopted this particular scheme.

So I looked at these two general fixes and ran the numbers all over again for this particular project. I looked at two different tariffs, one with a $10 fixed charge and one with a $30 fixed charge. And then, in each case, I adjusted the energy price. I used just the single tier energy price, and I adjusted it so that the tariff was revenue neutral. It would raise the same amount of money for SCE as its current four tiered tariff does.

Oh, by the way, SCE’s current customer charge is like, 90 cents a month, somewhere in that ballpark, it’s less than a dollar a month. So you can see that this is going to have a dramatic effect. And then I tried to estimate what SCE's avoided costs would be due to the solar generation. And then I threw in a CO2 adder based on the CO2 that a combustion turbine would produce but doesn't, because of the solar. And I priced it out at $50 a ton for CO2.

So here's the summary that captures it all. The first line is the numbers I've already talked about, about the net present value to customers under the existing tariff. The second one is the $10 customer charge, you can see that it puts quite a dent in the present value, the value that the customer gets from the solar array. And if you go to $30, it takes away a lot more. And finally, when you go to the buy-sell, it's almost a break even.

I put in the third-party financing, but it's not clear that a solar leasing company could viably offer a PPA at 85%, with the $30 customer charge, because the energy price goes down substantially, and it just might not be profitable enough. In an almost certainly wouldn't be profitable in the last option.

So what we see is that all of these fixes substantially knocked down the value to the customer. And you might think that's bad, but you have to bear in mind that at the same time, what it's doing is reducing or even eliminating all the cost shifting. In the separate buy-sell, you don't have any cost shifting. And also, it's eliminating uneconomic incentives to put in these facilities when in fact there are cheaper ways to produce this renewable energy.

Now, as the costs of solar continue to drop, this is not necessarily going to be the case. We're going to find that these projects could very well be very viable under any of these options.

I think the ideal fix is to make the retail tariffs truly cost reflective, because there are other benefits to that. But if you can't do that, and I think that that's going to be a heavy lift for the regulators, because there's going to be a lot of political pressure, there are going to be winners and losers, it's going to take forever to get those rates changed, and because of that, I think a more pragmatic solution is to go down the road that Austin Energy did, and go to the separate buy-sell.

This eliminates cross subsidies, it eliminates discrimination between large and small customers, and most importantly, it's transparent, which is totally lacking with net metering. You know, the subsidies that are passed through, through net metering vary from state to state, the size of the customer…we have no idea, you know, it's very difficult to get a handle on it. Whereas this thing makes it transparent. Before going to subsidize this stuff, let's subsidize it in a way where there's an explicit line item for that.

Question: I've got two questions for you, for clarification on your two solutions. First, on the straight fixed variable rate design, I assume you're proposing that that would apply to everybody, not just the solar customers?

Speaker 2: Yes, correct.

Questioner: OK. And the second question is on the issues of the buy-sell. Were you assuming that also the seller would be paying federal income taxes on that? Because it's income to the homeowner –

Speaker 2: Oh, that's a good point. That's correct. Yeah, because he'd actually be a QF, technically.

Questioner: Right, he'd be paying income taxes on everything he sold.

Speaker 2: That's correct. I have to admit, I hadn't thought of that. But you're right.

Question: So, in the "Austin" energy model, would there be two meters? One to see how much it's producing and one to see how much it's consuming? Have you incorporated the cost of that in the analysis?

Speaker 2: You need two meters, yes. Now, in the state of Texas, by tax and by law, all DG has to be separately metered. So, that's --

Speaker 1: At least in Massachusetts, it's required that there be a meter on the solar unit, because you can't get the REC right unless you have that information, and I suspect that's true in more than Massachusetts. So that's not adding cost. It's a cost that's already there.

Question: I know that you used California's numbers because of the tiered rate structure, but, in your mind, would the presumption be that in other states, where you don't have tiered rates, that the same results, the same kind of cost shifting, could be substantiated numerically, that there's no doubt in your mind that those same phenomena exist?

Speaker 2: Well, no, I wouldn't say there's no doubt in my mind. Yes, that same effect, that same phenomenon, exists everywhere. How big it is, is really a question of how high the tail block energy price is. And it's conceivable that these numbers would look very different if I ran it for another state. It's easy to do.

Questioner: So, just to follow up, I presume, then, that you would suggest the model should be run as states continue to look at what those costs are?

Speaker 2: I think that's a good idea. Not necessarily my model, but yes, I think that states should explicitly be looking at this.

Question: According to the "Austin model," you have in your footnote that the consumer buys all the energy at retail rates and sells it at the solar tariff rate. What exactly is a solar tariff rate? How is it set? And then, what's the payback for Austin?

Speaker 2: Let's see. I may not have those numbers. The payback under the solar tariff rate, as I recall, was about 18 years. It was way out there. When I calculated the solar tariff, it came out around $.12 a kilowatt hour, which is close to what Austin Energy came up with. I think theirs is about 12.9 cents. We used different methodologies, though. That 11.9 cents that I came up with was for 2014, the first year. And it escalates thereafter into the future. At the price of natural gas.

Austin Energy calculated their tariff on the basis of a levelized twenty-year forecast. You know, they forecast out all these costs for 20 years for the project and then levelized it. And that's what they pay. I mean, it's kind of like a QF contract. And that's going to give you, just by virtue of the calculation they did, it's going to come up with a higher number. I also didn't put anything in for distribution cost savings, because it's too difficult to do. The utility may be able to do it, but I certainly don't have that kind of data.

And I really question how big that number is. Even the studies that had been done, both by solar advocates like Volt Solar, and by some of the utilities, find that the T&D benefits are always very marginal. The biggest chunk of the benefit is the energy.

Question: When you talk about fixing the retail rate, and you talk about fixed and variable, you are not talking about what in my mind would be the ideal solution, which is to time differentiate the rate, because right now, as you know, it's common that residential rates don't have a time of use energy charge. But if you were able to go that direction, and you were able to get rid of the tiers, in my mind that would be the ideal solution, because as you know, the generation capacity cost, the transmission cost, is really triggered by mostly usage in the peak hours.

So when you have a flat rate across all of the hours of the day, you are giving a credit to the customer, maybe for solar consumption that is taking place outside of the peak periods. They are getting, in other words, a credit for generation capacity costs, for transmission costs, and it's not really giving savings to the utility. So I wonder if you have considered, or have tested, what would be the impact of using time of use rates in addition to having a facilities fixed charge.

Speaker: OK, we finally got to the question, and it's a whopper. Yes, I did. Because the separate buy-sell, the fourth line here, the way I calculated what was paid to the customer for its production, I basically simulated the hour by hour generation of the solar panel using NREL's model, the PV watts model.

And I took the California ISO LMPs for the most recent year available, 2013. And I basically paid them the LMP. So that covers the energy, covers the transmission congestion, on an hour by hour basis. Now, that implies that they're on an hourly time of use rate, a real-time rate, or maybe a day-ahead rate. To fully capture it, that's what you'd have to pay them on that basis. Which you can, because the meter that you'd use to measure what the facility is putting out capture the energy on a 15 minute basis,.

Now, on the capacity charge, I did look at generating capacity. The Cal ISO system peak, over the last 10 years, it always occurred in the summer months, obviously, and it occurred, in almost all those cases, between 4:00 and 5:00 in the afternoon. There were a couple peaks that were maybe 3:30, 3:45, but they were roughly in that very narrow time band.

So what I did was, I looked at the output of the solar array for that hour, through the months of June through September. And because I don't know what month that peak will occur, I just took an average of those hours in those months, and looked at what the generation was, the average kilowatt hour output, and then credited them with the carrying cost of a new combustion turbine. It's about $105 a kilowatt year.

Speaker 3.

My name is …, and I'm a net metering advocate. [LAUGHTER] Thank you.

Good morning everyone. I'm going to spend probably around five minutes, I hope not more than that, addressing the issues around net metering and subsidies. I've been listening to these arguments for about 20 years. And frankly, I'm kind of tired of them. On both sides.

And I think there's actually an interesting conversation to be had, that we've touched on, but really only briefly, on more forward-looking issues. And so I'd like to kind of shift some of the discussion to that. I could spend more than my entire time just going point by point through what we've already heard from Speaker 1 and Speaker 2, but it's not really interesting for me, and I don't think it would be that interesting for you.

So let me make a couple of quick points. I like to try to keep things simple. Even when they are complicated. And one simple way to think about net metering is that, from the utility's perspective, it makes high energy consuming customers look like low energy consuming customers.

In other words, to a utility, a net metering customer is just like a demand sink, right? They have all the same infrastructure, all the same resources that the utility is providing. All the same functionality and services the utility is providing, but they're buying less energy. And it really is that simple.

And the reason I think that's important is that we have, throughout the country, some customers that buy 4,000 kilowatt hours a month, and some customers that buy 35 kilowatt hours a month. And we don't generally discriminate among those customers. So I don't understand why we're talking about discriminating against these customers simply because instead of turning their lights off, or powering their lights with more efficient LED lights, they're instead powering those lights with a rooftop PV system.

Now, there could be one very good reason to do that, which is, if they're actually imposing a burden on the system, on the grid, essentially. But with an important caveat that I'll come to, there are no incremental costs to the utility associated with net metering.

One way to look at it is, many net metering customers actually never deliver any energy back to the grid. This is not true, typically, for residential customers, unless their PV systems are very small. It's quite often true for commercial customers. Especially big box retailers, for example, that are open seven days a week. So all they are doing is reducing the amount of electricity that they're buying from the utility. They're actually not delivering energy back to the utility.

But let's take the situation where those customers actually are delivering energy back to the utility. And my friends among utilities say that that's a really important difference. And to me, it's really a distinction without much of a difference. Because in most cases, that existing infrastructure that's there to serve that customer can accommodate the level of energy that's being delivered back to the grid.

Without any infrastructure changes, the utility doesn't have to swap out the meter for these purposes. It doesn't have to upgrade its distribution line. It doesn't have to replace a transformer. That existing infrastructure can accommodate that PV system. So there are no incremental costs to the utility. So what we're really talking about here, is a very real issue, which is, that it pretty clearly is a loss of revenue to the utility that's disproportionate to the cost savings, which, except for the fuel costs, are essentially nil. Now, again, to make my first point, it's a loss of revenue that's comparable to what the utility sees from serving many, many low energy using customers who have the same infrastructure as high energy using customers, but don't pay anything any different.

Or, to use another example that I like to use, if I have a primary home that uses a thousand kilowatt hours a month, and I have a second home that I visit once every few months for a weekend, the cost to the utility of serving those two homes are the same. But I don't see a differentiated rate structure. I'm not penalized for owning that second home that uses less energy. So, again, why do we penalize these customers because they're using less energy through this particular means?

But let's go back to the revenue loss issue, because I think that's an important one. Is that revenue loss a problem? I think Speaker 1 made a reference to critical mass being important. And I'd like to focus on that for a minute. In the vast majority of states, probably 46 out of the 50 states, this is a non-issue. The number of net metering customers that are enrolled in these programs in over 40 states across the country are so small that the revenue loss we're talking about is inconsequential.

So this is really only an issue in a few states. It's an issue in California. It's an issue in New Jersey. It's an issue in Arizona. And it's an issue in Hawaii. And I would suggest that in basically every other state, including states where utilities are complaining that the sky is falling over this issue, this is really of no consequence. And, frankly, my last point on the subsidy issue is that I'm frankly a little frustrated by a discussion around subsidies, because it doesn't seem to me like fixing the net metering problem results in economically rational rates throughout our systems.

The entire system is rife with cross subsidies of all kinds. I think everyone in this room knows that, right? We have middle and high income customers subsidizing low income customers.

We have urban customers subsidizing rural customers, because the T&D costs for serving rural customers is much, much higher. And we have customers that use electricity at night subsidizing customers that use energy during the day, just to give a few simple examples.

So if we look at the magnitude of these numbers, I just don't understand why we have so much focus on this particular issue. Especially in the vast majority of states where the magnitude of the numbers we're talking about is trivial.

All right, so I'm done with that, I'm happy to come back to any of this, but I really want to move on to what I think is a more fruitful discussion, and I think also, in its own way, a provocative one that'll trigger a lot of stimulating conversation.

There are a couple things that we're not acknowledging. First of all, almost as a side point, I think we're not acknowledging that we have a global imperative to reduce carbon pollution. And it's not getting a lot of discussion in this room, in this venue. And I happen to think--and I'm showing my bias here. I mean, I didn't get into solar energy because it seemed to provide an interesting near-term opportunity. A few years ago, a seatmate on an airplane asked me what I did, I said, "I'm in the solar energy business," and he said, "Ahh, great timing!" Well, you know, I'd been toiling in obscurity for 20 plus years in this arena. So, it may have seemed like great timing to him. It seems like a long slog to me. But the point is, I got into this because I thought we had a problem we needed to solve, long before the climate change debate really erupted on the public scene. And part of the reason I do what I do is because it seemed to me that looking at the array of low carbon and carbon free energy resources that are available, wind and solar are the two that have the greatest potential.

And I hear a lot of people expressing frustration about, you know, public support for solar energy and policymaker support for solar energy. But there's a reason why people are supporting this, and, by the way, there's a reason why the public overwhelmingly supports this stuff. And it's not economically rational, at some level. But it has a tremendous amount of support, for reasons that I think are, in their own way, pretty compelling.

I'm a strategy guy, so I've gotta think big picture. My first big picture thought is, solar is a big part of the long-term solution to the carbon problem. And yes, utility scale solar is great. My company does utility scale solar. But distributed solar has a whole bunch of really interesting and positive attributes that mean it should be supported as well.

Now, is it time to look at the support mechanisms we've created? Yes. I'm happy to have that conversation. I prefer to have that conversation in the states where it's become relevant, where it's actually consequential, where that conversation actually has some legs. But I'm happy to have that conversation.

The other major thing that I wanted to point out is that (I'm saying this a little bit tongue in cheek) I'm a believer in the inevitability of technology. And this PV technology, and a variety of other distributed technologies, are coming. They're here, and they're coming. And none of us are going to stop the progress. We can slow it, we can impose punitive rate designs, we can eliminate other subsidies, and that'll make a difference. It'll slow it down.

So we can have a debate about whether that's in the public's interest, to slow it down or not. But we could do that. But these technologies are coming, and they're getting cheaper. In my industry, the cost projections…I don't think I need to tell this audience that PV prices, the price for PV modules, not complete systems, has dropped 80% in the last decade. Most industry projections are they're going to drop another 30% just in the next few years.

Another interesting point on the technology side is that we've got an array of other distributed technologies that are increasingly the focus of a lot of investment, not only at the early stage R&D level. My company is doing pilot programs on PV with storage integration, in three different countries around the world.

Is storage cost-effective today? No. Is it going to be cost effective next year? No. Or maybe for very limited applications in very limited geographic circumstances. Is it going to be cost-effective in five years, or 10 years, or at most 15 years? Absolutely. And I think we need to be thinking about that now. And I think we need to be thinking about solutions to the problems that Speaker 1 and Speaker 2 and others have been raising in the context of what is coming, not just what's here today. Because storage in particular is going to have a hugely disruptive effect on the traditional electric utility service paradigm. And already, by the way, there's a study that came out, literally I think just yesterday or maybe the day before, the authors include the Rocky Mountain Institute, CohnReznick, and another energy consulting firm, I think, called Homer Energy, and one with the provocative name, Grid Defection. So, you know, you can look at the study. There's a four page executive summary. You know, I'm not a technologist, I don't know whether, you know, the price of storage is appropriately reflected in that study or their projections are reasonable.

My point is, yes, I'm an optimist. I think it's going to be economically available. And one of the points they make in that study is that today, in Hawaii, PV with storage, on a standalone basis, meaning with the power electronics and so on, that let customers serve their own electricity needs, essentially, completely independent from the utility, is a cost effective value proposition.

Now, why is that the case in Hawaii? Well, because they have the highest rates in the country and they have some of the best solar resource in the country, and certainly the most consistent solar resource season to season, which is a big deal. And because they don't have very high loads. They don't have very substantial air-conditioning loads, for example.

So is that an isolated case? Yes, it's an isolated case. Bu, are we moving in that direction in a variety of other jurisdictions? Absolutely. Can I say with certainty that it will be here, we'll reach that crossover point in four years, or 4.2 years? No, I can't say that.

Can I say with certainty it will come at all? No, not with certainty. But I'm really confident that it will. So, to me, that's the issue that we should be talking about. Not really about net metering.

I mean, if I had to call the shots on net metering, and that's not my job, I would say, net metering has played a really important role. It's been a really foundational policy in promoting early investment in this technology when it wasn't really cost-effective. And there are states where it's become very cost effective. It's served that purpose, and maybe we need to look at something else. I'm totally open to having that conversation.

But again, there's 46 states were the market penetration of distributed PV is, it's noise. A few hundred customers maybe. I don't think there's a state other than the four I mentioned, I might be wrong, someone tell me if I'm wrong, where there's more than, you know, 1%, even on a capacity basis, not to mention energy basis, where more than one percent of the state's energy, of generating capacity, is supplied by distributed PV.

So I would say, let's say that it's good for every state to get some experience adopting and integrating these systems. Let's figure out a reasonable benchmark, whether measured in megawatts or percent of capacity or something. And let's stop having this conversation until we get close to the benchmark. When you approach that, then you start having the tough conversation about what comes next. But until you're approaching that, leave it alone.

What's the harm? Let's focus on the next really important conversation, that it's important to have in that handful of states that I mentioned where this is going to be, if not already today, an important issue. And I don't know who the woman is in the back who raised the issue about time of use pricing, but I think when you look at the PV and storage combination, I think what you're talking about ultimately is essentially customers' ability to completely manage their own energy use.

And what that means is, they have the ability to respond on a real-time basis to any price signal that the utility delivers to them. So if the utility wants the customer to use less electricity on a hot summer afternoon, they can send that price signal, and the customer will respond. If the utility wants the customer to use more energy in the middle of the night, they can send that price signal, and the customer will respond.

Customers essentially will have their own value proposition, they'll invest in PV and other distributed storage and other distributed technologies for their own benefit, because they will figure out how to arbitrage whatever rate design you impose on them.

We could leave it at that, but I think, instead of demonizing these technologies, we ought to be looking at a way, because finally we have the opportunity, with not only PV, because PV alone, I'll be the first to acknowledge, doesn't provide these benefits. PV with storage, demand response and other energy management capabilities, with monitoring and control functionality that gives utility total visibility and even some functional control over these resources--even a residential PV system can deliver ancillary services, can load follow, can provide all kinds of benefits back to the grid.

Now, when I really want to get people riled up, let's see if it works in this room, I tell people, I've been working with utilities for 25 years, one of the really interesting things to me is that there's always been a wall, I think the utility folks in the room will agree, between the transmission folks and the distribution folks.

And I think that wall is going to come down, because of these issues. And to me, the most obvious example of that is the Cal ISO's duck chart. I think the Cal ISO has thought, until recently, and I'm sure there are people who think today, that that's a problem to be solved at the transmission level only, basically through additional generation and through additional transmission investments.

And my very intentionally provocative statement is, I think the duck chart problem can be resolved partially, substantially, or even completely, at the distribution level. Not today or tomorrow, but in a five or ten year time frame, we're going to be able to finally capture the value associated with these distributed resources, and the value, not just for the customer, but the value they deliver back to the grid.

Speaker 4.

Thank you. Well, welcome to my life. These issues are very much front and center in California. And let me just give a little background of kind of where we are, and how we got here. I mean, California is probably one of the most pro-solar states in the country, maybe competing with Germany for most pro-solar place in the world. And I'm talking about that, not just based on the policies, but because the policies are reflection of where the public and specifically the voters are.

You know, we started down this road probably sooner than other places. And we also have a climate that's very suited to it. I started to make a list of the policies in California, and it's somewhat amazing. Well, first of all, we have full retail net energy metering, and have had it for, I don't know, 20 years?

And you know, the statute always had a cap, I think it started out at half a percent of system peak load, and it was amended at various times over the years. It's now at 5%, and the PUC, a year or so ago, voted out a decision that interpreted the 5% as not 5% of coincident peak load, but 5% of non-coincident peak. Which, looked at in one sense, was a very odd decision, because you know, nobody even measures the accumulated non-coincident peak.

It was, quite frankly, a political decision by the commission to force the debate back to the legislature, where it really needed to happen. And nothing was moving forward in the legislature at that time. But once we issued that decision, it very quickly grappled with the issue and implemented some new legislation, interestingly enough, kicking the problem back to us.

But we did get some action from the legislature. But net energy metering (NEM) is just a small part of the solar policy in California. We had, you know, under Governor Schwarzenegger, the California Solar Initiative, otherwise known as "a million solar roofs," that provided explicit subsidies for the installation of solar on a stepwise, declining basis. And the idea there was, you know, the technology back in 2006 was not necessarily that attractive for a lot of people, but by starting out with a fairly significant subsidy, and then ratcheting that down over time, the hope, which turned out to be reality, is that as the market was stimulated, you got more economies of scale, the price of PV would come down, and you could take away those subsidies.

And they are largely, in the residential market, gone at this point, except for the carve-out for low income and some multi-family, which has not had the same degree of uptake. For commercial, I think there's still some, and it varies by utility. But I mean, there were 10 steps, and we're well down into the lower steps at this point. And the program continues to be going strong.

Now, on top of that, we added what's called net surplus compensation. Under the original NEM approach, if you generated, over the course of a year, more than you consumed, that that was just lost. I mean, you could carry it forward forever, but you could never monetize it. Under legislation that was put in place a few years ago, if you had a net surplus (and actually at least in the residential space, very few people do, or don't have very much, because the system is supposed to be sized to the customer's load) the surplus used to be lost. We were directed to establish a price for that, and interestingly, what we ended up with was something very similar to what Speaker 1 was advocating. I mean, we don't have LMP pricing at retail down to the node, but we have what are called load aggregation points, and the payment for net surplus is the load aggregation point price, plus the renewable energy credit value. Very low, you know, four or five cents, something like that.

The author of the legislation wasn't very happy with that decision, but that's what the commission decided in that particular case. And aside from these, we also have essentially free interconnection for NEM customers, and no kind of standby charge of any sort. So it was a very aggressive program, and it's been quite successful.

The last numbers I saw, we had somewhere between two and two and a half gigawatts of NEM capacity in California. It would have been bumping up against the old 5% cap, but with the reinterpretation of the cap, 5% would now be about a little over five gigawatts. So it's moving forward. If anything, the installations are increasing, they're not slowing down, even though the CSI explicit subsidy has gone away.

As has already been discussed, the rate design in California for residential has been steeply tiered for a set of historical reasons going back to the energy crisis we had in 2000-2001. At that point, the utilities were effectively insolvent, and the state had to step in and serve as the retailer of power, in essence, for a while.

And as part of that legislation, the rates for the two lowest tiers of this rate structure were frozen. And I think the thinking at the time was, "Well, gee, it wasn't the small customers who were responsible for this, it was the large customers who pushed for restructuring, so the legislature protected the first two tiers of usage from the rate increases that were coming through.

But that was locked into statute in a way such that for a good 10 years, all of the rate increases in the residential class went on these upper tiers. So you went from rates that were maybe 10 cents and 12 cents at the beginning of all this, to the rates that were shown earlier, where you have 12 cents in the lowest tier and in the 30s in the upper tier. There have been times when it's been as high as the 40s, approaching 50 cents. Eventually some moderation was added there, but it's put California in a place where very few others have gone, except maybe some water utilities in a drought situation, that have put in those kind of rates as a form of rationing. But this created a much bigger NEM subsidy, if you want to call it that, than what was the case when NEM was implemented.

And so last year, primarily at the urging of the utilities, but with a lot of input by other groups, a bill passed the legislature that took off these legal constraints on the rate design in some respects. But the commission now has the authority to determine the residential rate structure within some bounds that the commission hadn't had for 10 plus years.

And the legislation also addressed net metering. And it basically set this five or so gigawatt cap, but it said that when the amount NEM generation reaches five gigawatts, or by July 1, 2017, whichever comes sooner, the commission was instructed to come up with what's affectionately known as NEM 2.0. And the commission has only very broad guidance as to what that should look like.

So, between now and the deadline of the end of 2015, so, roughly two years from now, the commission will be tasked with figuring out what comes next in terms of NEM. And again, you know, all these options are on the table. You know, is it a buy-sell arrangement? Is it net metering?

But at the same time, the residential rate design is under review, and almost certainly will lead to a moderation of the tier differences, and perhaps even more drastic changes. So a lot's going on, and that rate reform effort will be reducing the benefits of NEM, independent of what happens with NEM itself. If there are structural changes to NEM, then, you know, it could be in essence a double whammy on solar.

And there's a lot of resistance to that, politically. And there's a huge amount for us to sort out here. One of the most interesting things, and an issue that we have to decide by the end of next month, is in this statute saying, you know, "Move to NEM 2.0," the legislature also recognized that a lot of people have made investments based on NEM, so they adopted a grandfather clause. If you had put your system in place before a certain date, you would keep the NEM 1.0, even after NEM 2.0 was introduced for new solar customers. And the commission is directed, by the end of next month, to figure out how long the grandfathering period should be. The legislation suggests or encourages, but doesn't exactly mandate that we look at, well, what's a reasonable payback period for those investments that were made in solar?

The governor, in his signing message approving the bill, said, “Well, I’d like the PUC to consider that the expected life of the system.” And by most accounts, those are two quite different things. The payback periods, as we saw earlier, are probably in the range of, you know, seven to 10 years. The expected life of the system, people are arguing for 25 or 30.

We now have a proposed decision authored by President Peevey that’s would adopt 20 years as sort of a compromise between the longest possible payback period and the shortest likely life of the system. We will be intensely lobbied over these next few weeks over whether that prevails or whether it’s changed.

But I think it’s worth bearing in mind that even for these grandfathered customers, as the rate design changes, and the tiers are flattened, the benefit of NEM will be going down even as they’re grandfathered. One of the challenges of trying to figure out a payback period is that the payback period is completely dependent on the rate design and the cost that the customer can avoid through NEM.

So without knowing what future commissions are going to do, that payback period is almost indeterminate. The seven to eight to 10 years is based on the rate design today, which, as I indicated, is almost certainly going to change.

On top of this, we have other programs. Of course we have the most aggressive RPS in the country. But RPS is basically for systems 20 megawatts and above. We have a different program, called the “renewable auction mechanism,” (RAM) for renewables three to 20 megawatts in size. And that program operates by setting a number of megawatts to be procured, and then the utilities put those out to bid in tranches and suppliers offer the price that they’re willing to accept for what I believe are 20 or 25 year contracts.

And those prices have also come down markedly. I think the last RAM auction was in the seven or eight cent range. And beyond that, for the really small units, the wholesale renewable generation between basically anything that’s not on NEM, up to three megawatts, is subject to a feed-in tariff.

The commission was directed to develop a feed-in tariff. We looked at that, but could not really figure out a right number for a feed-in tariff, so we designed kind of a reverse auction for that, where the starting price is the price from the last auction for the three to 20 megawatts, and then a certain number of megawatts are put out at that price. If there’s uptake at that price, the price goes down for the next round. If there’s no uptake, the price goes up for the next round. So, it’s a market adjusting feed-in tariff, which is just getting started. We’re very interested to see how that plays out.

So, basically, if you’re a legislator in California, you’ve got to have a bill on solar. It’s just part of the job. And every year, we have different flavors. We now have a community solar, we have a particular carve out for bio energy that’s allocated a certain number of megawatts under this feed in tariff…not just one form of bio energy, but several variations of bio energy to be priced separately.

One of the things that Speaker 1 said that continues to trouble me from time to time is, you look at the prices, and there are clearly economies of scale in solar and other renewable technologies. You know, I’ve asked a lot of people, “Where do the economies of scale get exhausted?” And most of the time I hear something around 20 megawatts, that you could build a 20 megawatt solar project for about the same price per kilowatt hour as a hundred megawatts, or we have some up as well to several hundred megawatts, but it seems as if you could get about the same price for anywhere in that range. But because that price doesn’t work for smaller units, we have other programs to pay higher prices for smaller solar. And I do wonder about the wisdom of that. You know, I think one can be a big fan of solar energy and a little bit more skeptical about highly distributed solar, and whether it makes as much sense as some of these larger solar projects that are now coming in at very attractive prices.

I think part of the rationale for what California has done and is continuing to do is to drive technology. California has a long history of this, with our auto emissions standards. You set a target that seems impossible for several years out and cross your fingers and hope that innovators will find a way to make that happen. And in many cases it has. There have been some cases where it hasn't, and then the mandate is removed or pushed off. But it's a very conscious aspect of California policy to try to drive technology.

That is certainly true with solar. It's now happening with storage, where we've put in place explicit storage procurement mandates for the utilities, again, to try to drive the market. It may not be cost effective today, but, you know, if half of what I am told is true, it may get there faster than any of us think.

So from a California perspective, all of this is driven by the desire for greenhouse gas reductions, as well as reductions in co-pollutants, the more traditional regulated emissions. You listen to this laundry list that I've gone through, and believe me, I've only scratched the surface on the number of different programs in California. People are, I think rightly, asking the question, "Are all these legislative carve outs and set asides and preferences the right way to do this? If the goal is, ultimately, greenhouse gas reduction, shouldn't we be looking at ways to achieve that in the most cost-effective manner possible?"

These discussions are happening at the highest levels in the state. I think there is a fair amount of momentum to move toward a GHG standard, rather than all of these programs. But each one of those programs has some legislator's name on it, and question is, is that going to be possible, to wipe away all the carve-outs and preferences and come up with something that, from an economic standpoint, is much more rational?

General Discussion

Question 1**:** Does today's discussion also apply to other forms of distributed generation? Like generation powered by natural gas?

Speaker 1: It doesn't change the economics. It does change the politics.

Speaker 4: Certainly, in terms of California politics, it would be a very different thing.

Question 2: Speaker 3, I'm troubled by your suggestion that there's no cost to the grid of people selling power back to the utility. Why not?

Speaker 3: That's a great question, and I'm happy to clarify. The reference I made was to individual systems interconnecting, and the facilities that are associated with those individual systems. OK? So, my point was that if I sign up for net metering, the utility doesn't have to make any changes to the grid infrastructure to accommodate that. Right? They don't have to put in, as I said, new transformers, new wires, new meters, new equipment…

The big caveat on that is, as the market penetration increases, you do get to a point where you start putting stress on at the individual circuit level. Now, I think, at this point, there's only one state where that issue has emerged, and that's Hawaii, where we now have, you know, 10, 15, 20, 25% market penetration of distributed PV systems on certain feeders. And the utility, HICO, which actually has been, relatively speaking, quite collaborative in trying to address and overcome these challenges, is in the middle of a very challenging proceeding to figure out how to address this.

That's the big caveat to what I said. At low levels of market penetration it's not an issue. I haven't heard of any of the utilities in Arizona, getting to the point where they're actually having to consider making distribution system upgrades in order to accommodate the incremental net metering system. But it's possible that I'm mistaken.

Questioner: I guess my further probing is that there is a cost to operate that grid. And so, philosophically, is it fair to suggest that someone who's using that essentially as an income stream to sell power back under net metering rules, do that for nothing? And I think you're suggesting that's inconsequential, and isn't really part of the discussion. And that's what I was trying to probe.

Speaker 3: I absolutely agree with what you're saying. To be accurate, what I said was, there's no *incremental* cost to the grid. There still are existing costs to the grid. And I think I said pretty explicitly that as the revenue drops, you essentially have to allocate those fixed costs, which are largely fixed, obviously, except for the incremental energy costs, among fewer kilowatt hours.

So, absolutely, that revenue loss results in rate impacts. So "incremental" is the key word there. Absolutely, those customers are using the distribution system, but they're not causing any incremental costs. It's just that the same costs of the distribution system are being allocated among fewer kilowatt hours.

Questioner: And that's part of the reason for my question. Because the word "incremental" was key, but what I didn't hear you say that there's still a cost, and someone has to pay for that, and is it fair for the utility to pay for that, versus the solar customer who's actually using their infrastructure as a mechanism to gain profit, or you know, sell power back. And I think that's a basis of contention that continues to happen in conversations between utility providers and the solar industry. And I'm just curious to get a read from the panel.

Speaker 3: And I agree with you there, as well, and we should hear from other people too. I mean, I do think everyone should be covering some portion of the cost of maintaining the distribution system that they benefit from. I don't have any objection to that. I do ask, why are we singling out this particular type of customer? Right? We don't penalize other customers who use less energy that their neighbors? Right? I mean, I'm sure you could find many customers who have a PV system, and many customers in the next neighborhood who don't have PV systems, who use the same amount of electricity each month, and who are basically making the same use of the distribution system.

So I don't see why we would create policies to favor one over the other, with respect to this particular issue. But we should hear from others as well.

Speaker 1: In the wholesale market, if a generator wants to sell to a customer, built into that, in the customer's calculations, is, what's the cost to move the energy from the source to the sink? And then you had a price. Here, we're saying to a generator, "We're going to relieve you of the cost of moving from the source to the sink. In fact, we're going to reduce that. We're going to actively discriminate in favor of the DG generator to the detriment of people who participate in the wholesale market and other sources of energy." So the way net metering works, it's an affirmative discrimination in favor of solar DG, or any DG, actually, to be fair about it. And that's the problem. That's why there is a basis for saying, "This is not the same as DSM, it's not the same as reduced revenues because of recession, or bad weather, or whatever. This is really different."

The question is, do you view this in the context of consumer behavior? Do you view this as somebody generating energy and selling energy, whether to themselves or anybody else? And if you're exporting to the system, why should you be relieved of having to pay?

Question 3: I'm curious to get your thoughts on the best way to incentivize storage.

Speaker 1: Well, actually, if you use the model I was suggesting, LMP, it does incentivize it, because if you have the energy to provide to the market at the time when demand is at its peak, you're going to make more money than selling it off-peak. So that actually is a market-based incentive for storage, as opposed to a specific mandate. And if something needs the technological goosing, it is storage. It's not solar PV, it's storage. And it seems to me that if you develop signals in the marketplace that provide incentives to solar PV providers to add storage, that would do it. So it seems to me you need to mix that into the pricing.

Speaker 2: I would say, though, that storage is going to be a lot more valuable if it's combined with wind, not solar, because wind energy is produced at a time when it's least valuable, in some cases when the price is zero or negative. If you could store that energy and then deliver it on peak, now there's a big value-added proposition there. With solar, much of that energy is in fact produced at times when energy is the most valuable, and so you would get that payoff immediately, without storage, just by selling.

Speaker 1: In some places that's true, and in some places it's not true.

Speaker 4: One of the other things that's worth mentioning that we're dealing with in California, is the effort to put in smart inverters on solar systems. And those would provide voltage and frequency control, and actually provide some benefits back to the grid, whereas, you know, there's concern now that with widespread solar on a circuit, you're going to be creating problems. With the smart inverters, there's a potential for value added. It's a value that's very hard to quantify, and we don't have market mechanisms at this point to price reactive power or frequency control at that level.

But I think probably within this year, California will initially allow smart inverters, which the current IEEE standards do not allow, and not too far down the line, they'll become mandatory. I think this ties to a problem in Germany, that they've had to go back and change out a lot of inverters, to get those capabilities. But it seems like that's well on the way to acceptance by the standard-setting organization and ready to put out in the field.

Question 4: I happen to represent utility scale renewables in the state, and the prices on those projects have dropped significantly. Our concern is that it's uncool to be utility-scale solar or wind in this state. So I want to raise two concerns: 1) If you assume a limited amount of available capital and subsidies, doesn't it make sense to use these resources as efficiently as possible? And 2) How is distributed solar generation any different from other forms of energy that we value in terms of avoided cost? Why don't standard PURPA principles apply?

Speaker 3: You know, it's hard to argue against making the most efficient use of a limited pool of resources, whether its investment capital or government capital, so to speak. And certainly not opposed, and you know this very well, to utility-scale renewables. We've got over a gigawatt of large-scale solar plants either operating, under construction, or soon to be under construction, in California. To me, it's not either/or, it's both/and.

But that doesn't speak to your point about how we're working with a limited pool of resources. So you do kind of have to pick.

Two other quick points on your first question. One is, I think you and I also both know that there are a number of constraints today on building the large-scale plants. They're a challenge from a development perspective, a challenge from a permitting perspective, and so, to me, from a public policy perspective, it's really nice to have more than one arrow in that quiver, and to be able to have mechanisms in place to support renewables at both the decentralized and the large-scale level.

And you know, even though we're continuing to build out the large-scale plants that we're essentially contracted for over the last five years or so, there is, as you know, very little in the way of new contracts for large-scale renewables. And certainly not that kind of scale.

The analogy I've been using is the snake swallowing the pig, right? And the California procurement of large-scale renewables over the last five years is that big lump in the middle of the snake. Yes, we're still procuring, but it's at a very different scale.

Your second point about asking how this is different from avoided cost principles--you know, there is a longer discussion here, I don't want to monopolize the time. I think the short answer is that utility studies over the last 20 years have demonstrated that there are direct, measurable, tangible, technical and economical benefits to injecting energy into the distribution system. I think some of the other speakers alluded to some of that.

So I think there is an incremental value. A typical wholesale avoided cost rate doesn't reflect that. So the question is, to create sort of a different kind of avoided cost that somehow accounts for those, and I'm glad you raised that, because I wanted to touch on…I think it was you, Speaker 2, that talked about the Austin model?

Speaker 2: Yes.

Speaker 3: Now, the Austin model is not avoided cost. It's a much more multilayered assessment of the value of solar. That's what it's called, "The Value of Solar Tariff," and it actually quantifies those values and ends up at a rate that is substantially higher than typical avoided costs.

It pains a lot of people, especially economists, to hear people saying that, you know, net metering is "rough justice," or is, you know, "approximately right." But when people are doing these value of solar calculations, they're coming out with an all-in value of distributed solar calculation that, guess what, roughly corresponds to the retail price of energy. Obviously it varies state to state, but that's what they are coming up with.

Questioner: There's a big gulf between 6 cents and 24 cents.

Speaker 3: Well, the 24 cents, in California, is a legacy of the tiered rate structures.

Speaker 2: Well, actually the Austin Energy Tariff that you're talking about is an avoided cost-based tariff. You can question, what costs did they count? I think there are problems with what Austin Energy did. I think this levelized cost calculation is one of them. You know? It gets them into the same problems that we got into with these QF contracts that were signed, that ended up above market, because they were based on a forecast of where energy price was going to be over the next 20 years, that turned out to be wrong. And, in fact, that's exactly what has happened in Austin. Every year they go back and they revisit this tariff, and they have to change it, because the forecast gets changed.

So the tariff is not 12.9 cents, it's, they dropped it. Of course all the solar energy people are up in arms over that. There's some sort of a state subsidy that gets included in there, and I'm not sure if it's a production tax credit, or what it is, but utilities are required to buy a certain amount of renewable energy, and to the extent that they buy this solar energy, they avoid having to pay that. So, that's rolled in. Who knows, is that truly an avoided cost? That's an administrative calculation.

Speaker 1: Speaker 4 was talking earlier about the legislature essentially saying, "Well, we need to go back and figure out, if we change these rules, what's rough justice for the guys than sunk all their money into the old system?" And so, if you use avoided cost calculations, and clearly those are based on assumptions that may or may not be correct, and usually are less correct than more correct, if you do that, then you're going to face this problem.

And it's the argument for why the other 46 states matter. Because if you don't get the prices right early on, or at least approximately right, you're going to have the exact same problem California has, that Speaker 4 described so well, because it's clear that distributed solar is gaining market share, which is fine, but it ought to gain market share based on market realities, not based on somebody's prognostications that are generally not accurate, or on some policy prescription that may or may not turn out to be, to get results that you want.

Question 5: I want to make a brief comment and then ask a question. The comment is, I think it's a mistake to think of paring storage with wind, or paring storage with solar. They're only indirectly related, and the direct connection is through prices. So storage is a technology that can stand on its own. And it should go to the places where the prices are most volatile, and it should arbitrage those prices. And that's the market there, and it doesn't have anything to do with wind directly or solar directly. So, that's just a comment.

The question I have here is, I accept Speaker 3's thesis, which I interpret as, inefficient pricing on small volumes doesn't amount to a hill of beans, so don't worry about it. And I accept that for small volumes. And I certain agree with Speaker 4's thesis, which is, this is a democracy, and if the people vote for something and they want it, then they can have it. OK, so that's fine, and I accept that.

I'm also worried about climate. And I think that's a real problem, and I think we ought to be doing something about it. But what I'm worried about is not Speaker 3's thesis on small volumes, but the message it's sending out about what's going to happen when we try to go to large volumes. And if we have very inefficient incentives, and the costs of these technologies are really too high, then you end up in a situation which you might call Spain. [LAUGHTER] Or you might call Germany. Or you might call the UK.

And you look at what's going on in those countries, and we had a session on that just recently, but what you're saying is, it's turned out that this stuff is really expensive. And when you get a lot of it, and it does amount to more than a hill of beans, then you get a reaction, which is, the public turns against it, the politicians turns against it, the fiscal system turns against it, the industry turns against it, and you have an unraveling of this consensus about trying to deal with this fundamental problem of climate change.

So I think it's actually the seeds of its own destruction, if we don't get the signals right and get the message right so that people understand it. And it's directing us in the wrong way. I don't think the problem is expanding the deployment of technologies that are too expensive. I think the problem is making those technologies cheap. And expanding the deployment really doesn't make them that much cheaper. That, I think, is actually a myth.

And so I think this is an ARPA-E problem, way upstream in the research technology, and we should be devoting way more of our time and attention and resources upstream there, not trying to find all these ways to deploy it downstream, when it's really not ready. Now, in some markets it is, and that's fine. But it's because I'm worried about the climate problem, and I think we're shooting ourselves in the foot if we don't do that kind of policy redirection. And I'm wondering, Speaker 4, when does the political system crack here, where it won't take it anymore?

Speaker 4: I think that's a very good question. And I mean, fortunately, you know, there are a lot of voices in California. Some of them have very loud voices. But in terms of the governor, he very much gets that. One meeting I had with him, he said, "Greenhouse gas is the defining issue of our time, you know, we've got to do this, we've got to do that…But the lights have to stay on, and rates can't go up too much."

And he sees that, and he expects us to try and somehow walk that tightrope such that we do all these aggressive things, and are world leaders, et cetera, et cetera, but the lights gotta stay on and the rates can't go up too much. And I don't know if it's possible, but that's our assignment, and we've got to try and carry it out. I mean, I've voted against a number of things that made me very unpopular, because I thought they were piling too many straws on the camel's back. And I think all we can do is try to do our best. It's a very challenging situation.

One of the things that's concerned me a little bit about the notion that, "Well, we can solve all of this by putting in fixed charges that aren't avoidable"--well, even the fixed charges are avoidable if somebody does solar with enough storage and they go off the system. So, you know, fixed charges aren't a panacea, because even they can be avoided at some cost. And so we've got to figure out a way to tiptoe through all these constraints and try to find something that actually works.

Speaker 1: You're right, the fixed charges can become an incentive to bypass. But in terms of fairness, if somebody goes off system and wants to rely on the combination of their own generation and storage, that's fine, they're not imposing any cost on the system. They may be taking some revenue out, but that's fine. But the guys that are there, that remain connected and fully expect the system to be their battery and aren't willing to pay the full freight of being the battery, that becomes a problem.

Speaker 2: Yes, but just to keep this real, the cost of going off the system and being self-sufficient, based on a recent study, is something like six times the fixed cost of staying on the system and paying the fixed cost to the utility. It's not economic today. Maybe someday, but not today.

Speaker 3: Actually, I think there is a cost when customers go completely off grid, because the network economies benefit from having more people interconnected, right? So, I mean, if you have a significant percentage of consumers who avail themselves of the opportunity to go completely off grid, that does have impacts on the remaining folks who are staying on the grid. So I worry about that, too.

Speaker 1: I agree with that, but I wouldn't necessarily impose an exit fee on them for doing it. But if somebody remains on the system and expects to pay less freight, but get the same backup service, that's a problem. But you're right, if somebody leaves the system, that's a loss of revenue –

Speaker 3: Telecom analogies are overdone, but I just saw a statistic recently that there were 186 million wireline telephones in the United States 10 years ago, and there's fewer than 100 million today. So, you know, things change.

Question 6: If I understood this right, some of the fixes that folks are suggesting, at least that some of the panel is suggesting, include making retail rates cost reflective, so maybe pricing out that fixed component, or separating out the buy-sell components associated with load and distributed generation. And I think one of the panelists talked about using a fair auction or something like that to procure their renewable resources. So there's been a few fixes that folks are proposing.

So, one of my questions is to Speaker 3. I know you are a net metering advocate, but how do you feel about the fixes? Is there one that you favor more?

My second question to the panel as a whole is, we talked about storage technologies and whether PV and storage, or wind storage, you know, these new products, to the extent that storage technology becomes viable, does that impact your view of what the proposed fixes really should be? I'm guessing the answer might be that we might need further fixes down the road to recognize the value that storage brings. But I don't see that storage coming into play as inconsistent with those three fixes that have been proposed by the panel.

Speaker 3: I'll touch on your first question, and then I'll let other people address the second point. In terms of looking at those fixes from my perspective, I said earlier that I am not opposed to having all customers, including net metering customers, pay some fixed charge to reflect some component of the fixed cost. But I don't think that's the best solution, frankly.

And it's also a solution that, in my experience, appeals to economists. Because it is economically rational. I mean, economically speaking, that's the right answer. You know, you charge fixed costs as fixed prices, you charge variable costs as variable prices.

But unfortunately, no one else among the stakeholder communities favors that route. The energy efficiency advocates don't like it, the environmental advocates don't like it, the solar advocates don't like it, consumer advocates generally don't like it. So, you know, you don't have a lot of fans out there supporting that approach. People understandably like the idea that, with carbon and other pollution, we have a global imperative to try and encourage people to do more with less energy. And creating new rate structures that basically reduce the incremental price of energy is going directly against that, so I don't support that approach.

What I do see, and this actually touches on your second point as well, and I'm taking a lot of risk from my industry's perspective in saying this, I do like the idea of shifting more broadly towards time of use rates that do reflect the actual cost of delivering that energy at different times.

To be clear, that won't necessarily help my industry. Yes, solar generally produces electricity during the day, when it's generally more expensive. But as others I'm sure are more aware of than I am, in California and in many other places, the actual peak, the needle peak, so to speak, comes well into the late afternoon or early evening, when solar is producing nothing. So if you assume for the moment that the summer at 6 o'clock would be when the prices are highest, my customers are not going to capture any benefit from a system that makes that the highest priced energy, because they're not producing energy at that time.

That's where the storage issue comes in. I'm expressing my industry's willingness (many of my colleagues probably won't agree with me, but I'll say it anyway) to think about embracing those sorts of pricing structures, even though, today, I can't necessarily respond well to them, and they are not to my economic benefit, because I do have confidence that over time, with the integration of storage and other demand response and other energy management capabilities, we will be able to respond and create a different kind of economic value proposition that still enables me to sell more solar energy systems, but also benefits the grid, in terms of the bigger picture of problems that we've talked about.

Speaker 1: The questioner is right that storage is an independent variable from these products, but, in fact, there is no reason why a producer in the market can't offer an aggregated product and bundle them. And it seems to me that if you use LMP, if that provides an incentive to somebody to deliver a product that could deliver the energy whenever it most needed, that is an inherent price-based incentive to in fact aggregate storage with intermittent resources. The same thing would be true if you did the RPS auction I was talking about. But who's available and what time they are available is a factor in determining who wins the auction and in setting what the market clearing price is.

Speaker 4: I wanted to mention something that was proposed by San Diego Gas and Electric a couple of years ago, and it was dismissed at the time because it didn't square with the net metering statute as it existed then, but I think could be considered in this NEM 2.0 discussion. They proposed something called a "network use charge," which wasn't a fixed charge, but it was a charge that, if you were taking power off the grid, you would pay, and if you were putting power onto the grid, you would pay. But there wouldn't be any payment for the power that was generated and used on-site simultaneously. And that didn't fly at the time it was first proposed, but it has some interesting features that I think we'll be looking at as part of the NEM 2.0 discussion.

Question 7: Thank you. And I agree that we do need to look at pricing, and go to some time-differentiated pricing. I think it's absolutely something that could help these issues, and I'm not afraid of looking at it on a fixed-variable basis as well. I mean, something probably has to be done there to some degree, although again, we have to be very careful how we do that. And it's a huge issue with respect to interest groups and their support or nonsupport.

But what I want to focus in on for a second is on this buy-sell tariff. I think this buy-sell tariff idea runs afoul of the prohibition against undue discrimination. In essence, you are discriminating against that person who has that system who is really, as Speaker 3 says, no different than somebody who's reducing their use in some other way—through energy efficiency, their two kids going to college, whatever it may be. It's really no different than that.

But ultimately, you know, you're saying that the amount of energy that they use for themselves, to reduce their own load, they can't take advantage of that. And I think that saying, in essence, you in essence, can't self-generate functionally. You are generating all the time for the utility, and I don't think there's anything in the law that says that. I think the law, in fact the other way in most every state, says that you cannot have undue discrimination.

And I know Austin did it, but, you know, they're not a regulatory body. They are a municipality. So they live under different rules.

And I think the second fundamental flaw is, if you do this, then those individuals will be subject to federal income tax and state income tax laws, and that's just a nonstarter, just a complete killer. So, comment on that.

Speaker 1: Well, I mean, I think it is a different kind of animal than people that just conserve, or people who move from California to Nevada. I mean, it's a very different kind of thing. These guys, one way or another, they are in the energy business.

If they want to disconnect from the system, and they're not going to rely on the system for anything, that's fine. But as long as they're relying on the system when their system is down, or relying on the system to sell energy into the system, they are different. They're energy generators.

If you view them as just people, as the same thing as people that are running a demand side management program, you may come to your conclusion.

I don't. They are people that are producing energy. And it doesn't really matter to me whether they're producing for themselves, or whether they're producing it to export to the system, they're producing energy, and they ought to be treated the same way other energy producers are, and not benefit from affirmative discrimination in their favor.

Speaker 3: Speaker 1, doesn't it make a difference that the energy generation is not at the wholesale, large central station power plant level that's essentially being delivered through the entire transmission and distribution system? As opposed to a kilowatt hour leaving my house and going to my neighbor's house? Yes, they're both using the grid, but the nature and intensity of the use of the grid is completely different.

Speaker 1: If a solar generator reduces transmission congestion or produces other kinds of transmission savings, they ought to be credited for that. That ought to be inherent in their price, I would agree with that. But the distribution isn't priced that way. You could argue that maybe we should price distribution more like transmission, but that's a question for a different day. As long as we're not doing that, then I think distribution and transmission questions are completely different.

Speaker 2: Let me just address this issue of discrimination was raised. You know, discrimination is in the eyes of the beholder. And you can write laws that say, "undue discrimination," but that's a judgment call.

And in fact, if you look at the way retail tariffs are designed, to the extent that they're not cost reflective, they are by definition discriminatory. And almost invariably they are discriminating against the large consumer of energy. Because the small guy gets to escape a lot of those fixed charges which are being carried on a per KWh basis. So, basically we already have discrimination. And that's the first point. That's why I would argue that the best solution is to come up with more cost-reflective tariffs and get rid of that discrimination.

The other point is that there is a way around this income tax issue. And it's what Austin Energy did. They basically give them a credit against their retail bill, so that as long as they don't actually get a dollar payment, they're not subject to income taxes. Of course, that also means that if they are net exporters, you can't do that forever, so that puts a limit on how large the solar array can be.

Speaker 3: On the question of discrimination, I think FERC addressed this in the early days of the PURPA implementation, and reached the conclusion (because this came up specifically in a FERC proceeding) that customers were essentially entitled, as a matter of law, to use the energy they produce to offset their own load before exporting the energy back to the grid and being compensated for avoided costs. Some utilities have proposed essentially the buy-all sell-all type arrangement, and FERC flatly rejected that.

Question 8: For those who don't know, New Jersey has about 25,000 or so solar installations. Most of them small. And about 1.1, 1.2 gigawatts, a little bit less than 2% of our electricity.

I thought Speaker 3's argument on net metering was absolutely brilliant. And for some reason, I've never heard it before.

For Speaker 1, we subsidize energy efficiency. Most utility companies, electric companies, subsidize electricity for energy efficiency. So, why not solar? What's the difference between the two?

For Speaker 3, we do give others solar incentives now. Some states taxes, and other incentives. New Jersey has the SRECs. Clearly I've always thought the feed in tariffs were bad, New Jersey's never had them. We use solar renewable energy credits, and we did away with incentives, so they have the SRECs. And I think that's the way to do it, and I feel bad about Spain and Germany, but I could have said I told you so.

I think that we probably need to modify net metering. And how we change that dynamic pricing, real-time pricing for solar, time of use, that kind of thing, is something that states, especially those for that were mentioned, need to look at. I think that's probably the way to go to tamp things down.

On technology improvements, I agree with the earlier comment that we need more research money and the administration should have thrown the $2 billion not at smart meters but at energy storage. And smart inverters are definitely happening. And I know Princeton is going to do that with their solar, because they turned their solar off during Hurricane Sandy, and they don't want to have to do that.

Finally, I think storage with solar is a perfect match, whether you want to call it aggregated or not. And for New Jersey, at least, our peak is later in the afternoon on those summer days, but demand is also high at those high solar hours as well. And there is a company now in New Jersey that is developing a six hour storage battery for residential use. And that's what will get us over the hump on those days in Jersey, and probably in other states that are comparable to us.

And I think those costs are going to be going down. I mean, obviously, the technology is there now for this one company. And I expect, in the next five years or so, the costs are going down. So I'm really optimistic, which then leads to, obviously, the stranded costs issues, with all the distribution and systems that we're developing, because customers are walking because of extreme weather and because of cyber security issues, and the utilities have to keep up with them as well as we do.

Speaker 1: With respect to the argument about, "We don't penalize people for energy efficiency, why should we penalize for solar?" what we are doing when we are providing preferential pricing to distributed solar is we are blocking out more efficient renewable producers from the market. And why would we affirmatively create a discrimination actively in favor of a less efficient form of renewable energy over a more efficient one?

Questioner: See, I look at it from the customer's point of view. And for that customer, it's not less efficient.

Speaker 1: But the difference here is, where do the benefits go? There are benefits that the customer will get but that the system won't get--reliability benefits, there are a whole bunch of things that are individualized and have nothing to do with the system. So it may be that customers are going to make their own decisions. They should be able to do that. But you don't want to create a system that squeezes out more efficient producers by affirmatively discriminating in favor of a less efficient technology. It just doesn't make any sense.

Questioner: And the customers will be walking. This is a democracy, capitalism and all that kind of stuff. Customers are walking.

Speaker 1: That's fine, then they –

Questioner: So they don't really care whether it's less efficient [OVERLAPPING VOICES].

Speaker 1: All more reason to get the price signals right. So that when they walk, they understand what they're doing, and they have the right incentives to walk or not walk.

Speaker 3: You asked about the other incentives for solar. And that's a really good point, and I think Speaker 4 spoke very eloquently and at length about the various mechanisms. But the short answer to that question is, those incentives are going away. And that's the right answer. I mean, you know, the subsidies used to be massive.

And as the technology costs have come down, the subsidies have come down. The California Solar Initiative is basically done. The incentives in many other states and countries are winding down. The German feed-in tariff program is winding down. There still are incentives, but in a big picture sense, they are winding down, and the big thing that's out there is the federal investment tax credit, which is scheduled to expire at the end of 2016.

So, whether it's in two years or five years, but somewhere in that timeframe, my industry is going to be looking at a market that's essentially driven by no incentives or independent subsidies, but basically just based on rate design, which is why I think all of us are talking about the importance of getting the rate design right.

Speaker 2: Let me just add one comment on this whole issue of subsidizing energy efficiency. You know, there really isn't any difference between a distributed generator and an energy efficiency investment. And so, you know, as an economist, I don't like these subsidies that we give to energy efficiency. And if we got the prices right, we would get the right amount of energy efficiency.

And now, we're driving more into the system. Well, there's a carbon offset credit that we do have to take into account. But the other issue is that we can live with the energy efficiency subsidy, because you can't conserve your way down to zero. You know, there's only so much that you can do to cut your demand.

But with a solar panel on your roof, you can cut your net consumption down to zero, or even negative. So there's an order of magnitude difference there between the impacts that you get.

Speaker 3: We didn't address your final point about the risk of stranded distribution costs. And I have a really strong view on that. You know, I don't think it's, in the foreseeable future, going to make sense for us to be encouraging customers, essentially, to bypass the utility completely.

I mean, there are economies of scale, network economies. There are benefits to having all of us interconnected. The vision I see is a different one.

There is an interesting analogy to computers. We started out with big, you know central station computers with dumb terminals, right, that were consumers of that computing capacity. We went to the exact opposite end of the spectrum, where we had all these independent PCs, each of which was smart, and then we ended up going back to the middle, by still having these independent PCs, with all their independent smarts, but we networked them together to capture the value associated with information sharing and the web, basically.

That's the model that I think we should be thinking about, in terms of long-term vision. I don't think we should be discouraging customers from generating their own electricity at their residential or commercial industrial facility. I don't think we should be encouraging them or discouraging them from integrating storage with that.

I think we should be basically setting up a network of price signals, where those customers can self-generate or deliver energy back to the grid in accordance with what the system as a whole needs or wants them to do, in order to manage the whole system most effectively. And to have the grid taken out of that equation, I don't think is in anyone's interest, long-term.