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Session One.

Lowering Prices by Raising Costs: When Do Targeted Subsidies Create an Existential Threat to Open Markets?

If you are willing to pay enough, you can make anything look cheap. And for investments that have an impact on market prices, the winners can gain even though total costs in the system increase. Thus costly investments may look cheap. Open competitive markets can support efficient investment, production, and risk allocation under the assumption that market participants are price takers, not price makers. Renewable energy development, demand response, economic development, transmission investment and other public policy goals often require regulatory mandates that interact with the operations of markets in ways that make the investors price makers. Large-scale commitments based on public policy goals can simultaneously lower prices while raising costs, and substantially tilt the competitive playing field. How much tilt is too much? How much of a subsidy would unravel the underlying market, until only subsidized investments could be made? What policies would integrate well to use markets without destroying them? How can regulators balance the competing claims?

Moderator:

Good morning. The title of our session this morning is "Lowering prices by raising costs: When do targeted subsidies create an existential threat to open markets?" We have had sessions on this before. I remember one in February of 2008 where the same issue had come up. That one was called "Monopsony manipulation: Is no cost too high to get low prices?"

Speaker 1.

Good morning. It's an honor to participate on the panel to kick off the conversation. I thought this was a particularly daunting, although timely, topic to address, because not only are the other panelists much more well-versed in the details than I am, but--looking around the room last night and now this morning--so many people in the room are very involved in these issues. And

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so it's a little bit daunting. But my task this morning, to kick off, is simply to set the table on the issue, and then to lead up to a very vigorous discussion, I'm sure, throughout the morning.

It's an understatement to say this is a timely topic. This dominated the discussion at our annual meeting less than a month ago. The question, obviously, is. "when do targeted subsidies [and I would take issue with the "targeted" aspect of it, but we'll get into that in a moment] create an existential threat to open markets?" So I'm very subtle. The answer to the question "When?" is *now*. And I guess what we'll do is talk a little bit about how.

To set the table for those that aren't as intimately involved with this, I just want to explain how we got here. The next slide really captures it. Those that have been to Trenton know well the famous bridge in Trenton, and the sign on the bridge that says, "Trenton makes, the world takes." And that's a wonderful thing from an industrial standpoint and for many other attributes. But it's certainly a great concern with what's been happening in New Jersey, which we'll certainly talk about throughout the panel and the discussion. And the caption above it literally came into the in-box as I was putting the slides together last Friday. And it's the headline on the editorial in the current issue of *Public Utilities Fortnightly* by the editor, which reads, "Parochial Power Play." And the subheadline is, "Northeast politicians declare war on capacity auctions." And I would commend that to you. It really frames the issue very well.

Well, I led off with a picture of the bridge in Trenton, because I spent a good deal of time there in October, and more in November, December, and January. This really all started in Connecticut, at least from the Northeast perspective. And everyone here is well-versed in capacity markets. Other speakers may touch on it. But as folks know, we've had proceedings in both New England and in PJM declaring the prior constructs not to be just and reasonable. There were long settlements. There's been litigation. This has all been upheld. All the auctions are very well monitored, well documented and so forth. But there has been this tension with some of the states about the capacity markets. And as you all know, from a perspective of representing suppliers, capacity revenue is part of the key equation--capacity, energy and ancillary services--to drive investment. And part of the challenge has been that the focus at least in some states and in some quarters has been only on new investment. So if the capacity markets don't result in brand new power plants for people to go to ribbon-cutting ceremonies for, somehow the market isn't working, when in fact the data shows--and we can get into later how many existing resources would have retired—basically, the capacity markets are doing what they were supposed to do, which is acquire least-cost resources.

Nonetheless, this started in Connecticut. I won't read the quote on the slide. This is a longer quote from the internal market monitoring unit at ISO New England in 2009 identifying the potential for this to be a problem. And the reason why they did so is because in 2007 and 2008, the Connecticut legislature passed legislation. There were two RFPs. And the result was-- and this is key, because you'll see the common theme in what happened in Connecticut, is happening in New Jersey, and may happen in Maryland--is that resources aren't just being acquired because they're needed or for other reasons. They're being acquired for the express purpose of artificially depressing the capacity market prices in the interstate market, and in fact, that's the key point at the bottom of the quote there.

Moving to New Jersey, where I did spend a lot of time, this all started toward the end of October. Legislation was introduced in the state to award--at that point it was 1,500 megawatts, if I recall correctly--and this was also a jobs effort. This was in the State Senate president's district. There was frustration by some companies that the price in the capacity market--the energy prices did not justify new investment. And that's an important point to keep in mind when I bring you up to date on the latest developments. The argument was that the capacity market prices are too low. They're not permitting investment.

So the original proposal was very specific. It was very critical of PJM's capacity market. It required the plant to be of a certain type, in a certain location, and the legislation as originally introduced actually specified the per-megawatt per-day price at some $232 and change, clearly written for a specific plant at a specific location. It was styled as a pilot project to put 500 construction workers back to work and to create 25 permanent jobs. And I won't go through all the machinations in the legislature, as colorful as they were, except to say that it ended up at 2,000 megawatts.

And our point was that this isn't just a pilot project. If you did the math, with the $232 price, this plant would have a consumer subsidy of almost $2 billion. So our point was, this isn't a pilot project. This is $2 billion that the four utilities in New Jersey would be required to pass on to every consumer in the state with a non-bypassable charge. The electricity from the plant that would be subsidized could go anywhere, in fact would be required to bid into the PJM market. So when I testified, I said, this could go all the way to Naperville, Illinois, to where my brother-in-law lives and the other 50 million people in PJM.

And it was a contract for differences--that's the other key point to keep in mind. This is the common element that's also happening in Maryland, which essentially is, heads I win, tails you lose, if I'm the developer. Under the original bill, the developer got to keep anything over $232 a megawatt-day, but then the consumers would true up if the price were lower. And that did change somewhat in the legislation, and right now at least, a broader, open process is what's pending.

So the grand bargain--I think this is part of the debate we'll hear--is that yes, there are consumer subsidies and costs, but jobs are created, and the argument that the rate council made in support of the legislation was that it would in fact depress the capacity price more than the cost of the consumer subsidy. They based that on Wall Street analyst estimates, which had resulted in the downgrade of several company stocks.

The status is that the Governor signed the legislation about a month or so ago. The Governor actually wanted an unlimited bill at one point, but settled on a 2,000 megawatt cap. It's pending, so I won't talk about the details in light of folks that are working on that, but it's on a very fast track process. An agent has been hired by the BPU. Submissions came in earlier this week. In fact, there's trade press reports out this morning that there were 34 submissions totaling 6,400 megawatts for the 2,000 megawatts.

The key issue is, from our perspective, that the intent in here is quite clear to depress the price. We think that is not permitted, certainly under the spirit of the existing PJM rules. Our partner in the region of PJM, Power Providers Group, has brought a Section 206 complaint that's pending before FERC. PJM has filed a proposal. They have not been consolidated, but they are on parallel tracks for comments by March 4, and this is very much live and happening, because the next auction is in May, and under the terms of the legislation, any plant awarded a subsidy under the bill has to both offer in May and clear. And of course the "and clear" means they would essentially have to bid at zero or some low price, which is where the depression of the market price comes in.

The last wrinkle, which is not up here, because of the fact that it just happened on Tuesday, is that LS Power, the developer that pushed the bill in New Jersey, filed at FERC saying, "Look, the changes potentially to this minimum offer price rule that's designed to prevent anti-competitive bids from depressing the price, that's all irrelevant, because we actually have data which we're submitting confidentially that shows that we're well under the net cost of new entry in PJM." Remember what I said at the beginning--the rationale in the legislature was that the price was too low, and we need this subsidy because we can't compete. Now the argument is that we're so low that we don't come underneath the rationale for the rule. So it's a very interesting development, to be sure.

Just quickly moving to Maryland, in the interest of time, Maryland has been in a similar situation, although moving a little bit differently. The Governor had proposed legislation to reregulate the market in Maryland, as many of you know. That did not happen. Same developer frustration. Competitive Power Ventures has a permitted plant outside of Washington, DC. Again says the current market prices and the excess supply that was offered into these markets means we can't justify a new build, and so they made a proposal to the Maryland Commission similar to what LS did to the New Jersey legislature saying, essentially, "Pick me." The Maryland Commission wisely didn't pick the project, but opened up a proceeding to look at options.

The last bullet really captures where things are between Christmas and New Year's. A draft RFP was put out for up to 1,800 megawatts for plants in and around Maryland. And again, like the New Jersey legislation, it's a contract for differences, and the express intent and the provision would require plants essentially to bid at zero to depress the market.

Why does this all matter? And this will be very quick, because it's pretty well captured in here, and you have the slides. This is the table. Joseph Barring, the independent market monitor, filed this a month ago in Maryland. Essentially, if you go through these numbers, Maryland alone, if the 1,800 megawatts bids in at zero, depresses the revenues that we depend on to make investments, environmental and otherwise, by $1 billion. That's essentially what that chart says, if you work through the math. The next chart just shows it a little bit differently. So it's basically a little over a billion dollars. He reran the last auction, if these megawatts had been put in, and then if New Jersey and Maryland do what they're intent on doing--or may do in Maryland, and are on track to do in New Jersey, the difference is actually much greater. It's essentially $3 billion, which is captured on the next slide. So you essentially take the capacity revenues and reduce them by 45%. Needless to say, that has not been lost on Wall Street analysts.

The next slide, which is almost the end, is from the report of the market monitor to the Maryland Commission. And I think the last sentence is particularly telling. This is not just a generator/supplier issue. It would also reduce incentives for demand response, which is why we worked so closely with the DR providers and environmental groups in opposing the legislation in New Jersey.

And similarly for the last slide, the goal here is supposed to be to have more capacity. That's what at least the argument was. Yet the comments here indicate the obvious-- that in fact, if we go down this road of trying to subsidize excess capacity when it's not needed, the impact on the market will be both less investment and less demand response, and it will actually require more subsidies over time, which is why we believe it's not the right way to go.

And last but not least, lest you think this is a continuing contagion down Interstate 95, the good news, at least, is that the analysts believe, at least Brian Chin at Citigroup, that this is something that's not likely to spread to other states, although I have to say that the analysts, if you read their literature, are assuming that FERC will in fact do something to stop this from having the depressing price effect on markets and on the companies. And if FERC does not do so, then it's going to be an adverse impact.

Last but not least, this is not the only headache we have going on right now--EPA rules, demand response rules, and other things that are pending with implementation of financial reform-- so this is just part of a broader mix that gives us great concern. So with that, I look forward to the normal course of vigorous discussion.

Question: You talked about the structure of the New Jersey contract as a "contract for differences." But you used the term "heads I win, tails you lose." And you stylized it as a "put option." That confuses me. Could you clarify that?

Speaker 1: I'm glad you asked that. To be fair, the legislation did change as it went through, to their credit. So the initial version was clearly the $232. They got to keep anything higher. The consumer got to subsidize the difference. As it went through, at one point, they were going to cap it at $290--they got to keep everything between $232 and $290 a day. But in the final version, to be fair, and I'm glad you asked that, it did get set up to be basically a parallel approach that, if for some reason the market prices are higher, then they'll have to pay back the difference. The problem is that the market price--so I mean, $232 is what was in the bill--only once did the price ever go that high. And if the transmission lines get built, the PJM numbers show the price could be $100 a day. So that's why we were trying to point out that the subsidy is greater than the benefit. But I'm glad you asked that, because to be fair, and to be fair to the legislature, the final bill was more balanced.

Speaker 2.

When I'm wearing my climate scientist hat, I have the luxury of knowing that my positions are based on a careful reading of scientific evidence, and further, that the vast majority of scientists who have reviewed the same evidence have come to similar conclusions as I have, and I'm speaking in this case of the risks associated with global warming, and the role of human activity in creating that problem. Today I have an interesting experience that sometimes occurs when I wear my energy economist hat--that I find myself actually in profound disagreement with most of the people in this room, I believe, including those on this panel. And these are very esteemed people who have published a significant body of literature and white papers on the topics under consideration and have participated in market design committees and academic forums and generally have quite impressive resumes. In addition, they have reviewed much the same market data that I have.

But when it comes to the structure, function, and functionality of organized capacity markets, and the question of whether these markets are actually providing benefits for consumers and whether these markets can or do provide just and reasonable outcomes, we seem to come to radically different conclusions.

I think the most important distinction between the fields of climate science and economics for me is the question of evidence. Science is characterized by a subtle interplay between conceptual models and the evidence that supports or contradicts them. There's a rigorous process of analyzing and evaluating evidence and improving or discarding the conceptual models as the evidence dictates. In economics, evidence can often be harder to come by and more ambiguous in nature. This instance is a strong case in point. There is no real precedent. The markets are brand new. And with a few exceptions, the RTO regions have been basically in capacity surplus since the markets came into being for reasons having nothing to do with the capacity markets themselves.

Where evidence is lacking, theorists can find themselves somewhat less constrained. Under these circumstances, whichever side has the loudest voices or the most money or the most impressive resumes can dominate the conversation. This should never be mistaken as proof that their position are correct.

The title of this panel asks, "When do targeted subsidies create an existential threat to open markets?" I think this title presumes a level of agreement that I do not share. So I'd like to explore with you why. First of all, it presumes that we are having a discussion about open markets to begin with. With respect to so called organized capacity markets, this presumption is ludicrous. The markets themselves are administrative constructs designed to compensate for a perceived shortcoming in organized electricity markets. To some eyes, this shortcoming is "missing money" that should have been forthcoming from unrestricted price spikes, and to which all generators somehow have a right. To others, it is the fact that consumers are not able to respond to price signals in a way that would be consistent with a well-functioning, balanced market. For some combination of these reasons, and because of an underlying dogma that each individual resource must be financially viable on its own, although there is no upper bound to how much they're allowed to make, there was a perceived need for some sort of subsidy to supplement the low energy revenues earned by peaking generators. But for reasons that escape me, except of course in my electric bill, this subsidy has been designed to benefit all generators in each region, regardless of whether or not they need additional revenues.

Someone has managed to convince the market operators and regulators that this was the only route to economic efficiency, and more importantly, that a narrowly defined concept of economic efficiency is somehow the only important consideration--that cost to rate payers does not even figure into the equation. I disagree on both counts.

I'm aware that many will argue, and have argued, that a focus on market efficiency will in the long run lead to the greatest consumer benefit. This may be true in a nonexistent, two-sided perfect market with no barriers to entry. But it is a tenuous article of faith when applied to real electricity markets. And given the untold billions in costs to get to that uncertain future, it's no wonder that consumer advocates basically unanimously are not eager to take that bet.

The implementation of capacity markets based on these unproven theories has already led, predictably, to the transfer of tens of billions of dollars of ratepayer wealth to generation owners. I say predictably because this outcome was clearly anticipated by all parties and articulated by many. The whole point was to raise costs. On the other hand, there's not a shred of hard evidence that this process has led to new generation where it is most needed, or to avoided retirements of needed capacity or to cost-saving transmission investments. These are the ostensible purposes of the construct. There is no reason to believe that it would. It's just too good an arrangement for existing generation owners as it is.

It is true that capacity markets have led to impressive investment in demand-side resources. That is a positive benefit. But it has come at an astronomical cost, much, much greater--I would venture to guess thousands of times greater--than would have been incurred had states and utilities simply invested directly in this resource. Perhaps in response to this modest success, entities on the supply side, including many in this room, have poured considerable resources into making sure that the compensation for the demand resources is not too attractive. I'll speak a little bit more about that later.

The title of this panel also refers to "targeted subsidies." This made me consider what a subsidy looks like that's not targeted. I suppose I've already come up with one answer--a subsidy such as PJM's reliability pricing model, whose ratepayer support is provided not just to the resources that need it but are uneconomic, but to all capacity in the market. An example of an alternative, more targeted subsidy--and I have to take exception to the math of the previous speaker. A subsidy is not the total cost of the resource--the $2 billion that you mentioned. It's the difference between what is paid for the resource and what the market pays, so it's actually much, much smaller than that--an alternative, more targeted subsidy might arise if there were no organized capacity market, and in a scenario in which harmful and expensive electricity price spikes signal a threat to electric reliability. In this scenario, I don't think anyone would argue that it was inappropriate for a state such as New Jersey to order its utilities to get additional capacity built and to pay for it with a targeted subsidy designed to be least-cost through an RFP process. This would be a crucial alternative for states to pursue in the interest of protecting consumer welfare and improving overall efficiency of the electric system. It would not be your role or mine or the role of any outside expert to supplant the judgment of the state legislature and their perception of this need.

Those of us who suffered through the RPM (Reliability Pricing Model) process--I think there are a bunch of us in this room--we all recall that states quite reasonably and vehemently retain that right. Today some state legislatures appear to be coming to the conclusion that RPM and FCM are not going to get needed capacity built in an economically efficient manner, because the underlying construct is fundamentally flawed. New investments require a credit-worthy buyer to make a commitment for ten years or more. In New Jersey, and in many other deregulated states, there are basically no entities that can serve this role. Three year retail auctions are exactly inconsistent with three year forward capacity markets. There's too much uncertainty on the retail supply side to support long-term contracting. So generation would have to be built on spec, and the entities that might possibly make such an investment have a strong incentive not to do so.

In my opinion, the ideal endpoint for electricity and capacity markets would be a construct that is mostly characterized by long term procurement contracts, competitively attained and structured around portfolios of resources that would maximize consumer welfare while producing a reasonable rate of return for generation owners. Organized auctions would primarily serve in a balancing role--marginal cost markets for marginal resources.

Perhaps my believe in this construct is an article of faith as well, but it appears to be a faith shared by most stakeholders who pay more than lip service to consumer interests--an interest that fundamentally includes both price and reliability. If the markets as currently structured will not and cannot lead to this end, then states have a compelling interest in finding a way to decrease their reliance upon them.

To wrap up an earlier point, it seems to me that there are two and only two ways that high capacity prices have actually led to the reliability-oriented investments that such price signals would ostensibly support. The first is demand response payments at a rate high enough to overcome well-established and well-known market barriers. The second is state mandated investments in needed capacity to compensate for a clear lack of private investment. In both cases, the suppliers and the experts who work for them have protested stridently that the market was being corrupted, citing their concern for the impact on consumers in the long run. Perhaps I can be forgiven for observing that these entities have a very strong vested interest in high capacity prices. Perhaps the best interest of consumers would be better left in the hands of those whose judgment is free from such influences.

So do targeted subsidies under consideration by states create an existential threat to well-functioning capacity markets? They emphatically do not. They are a rational response to a one-sided market structure that is harmful to and exploitative of consumers under circumstances where actors on the demand side cannot respond themselves. If these investments are suboptimal based on a narrow reading of economic efficiency, that does not make the irrational or wrong. It just reflects the distorted incentives to which they are responding.

The most likely outcome of this process will be a long term resource adequacy, procured through a combination of state sponsored investments, long term contracts and a much smaller spot market to balance shorter term supply and demand. This, in my view, and from the perspective of consumers, would be a significant improvement. Thank you very much for your attention.

Speaker 3.

Good morning everyone. I guess, given my spot on the panel, I will say that I will take as given the capacity market constructs in what I'm going to talk about, and basically go back to a point that was made in the overview, talking about the tensions that some states have in sponsoring capacity, and what I will mostly do is contrast two different approaches for you.

So I'm starting from the same quote, where there is a tension, given some states' sponsoring capacity, that in doing so they do have an effect on capacity markets, in ways that make those investments set or actually make the price on the market. And throughout the presentation I'm going to call that "sponsored entry." And the ISO, whether it's PJM or the New York ISO, or ISO New England, actually reacts to those sponsored investments through changes in market rules, and whether it's the New York

ISO, PJM, or ISO New England, there are specific rules that try to address this phenomenon or the effect that these sponsored investments would have on the capacity price. And as was mentioned in the introduction, there have been recent changes, in particular the ISO New England has made a filing in front of the FERC to expand its current rule, which is called the alternative price rule, or APR. There were other modifications to the forward capacity market that were filed at the same time, but one of the big pieces of the changes that are being proposed is about this alternative price rule, or how do we correct or cope with the outcome in the market that comes from sponsored entry?

Same thing for PJM. There's been a complaint by generators following the New Jersey legislation and asking for expedited changes to the rules in PJM, again to deal with this sponsored entry, and in response to that, PJM expects to offer various simplifications of that rule to make it more effective.

So what I want to do is kind of go a little bit into the details of those two rules and try to contrast those two approaches, and I'm going to contrast them in the following way. One of the approaches to dealing with the fact that those sponsored entries can make or set the price is simply to view that as being market power, buyer market power in this case, and to mitigate the offers. So say there is an entrant that's being sponsored, that's being subsidized. They would be providing a bid in the capacity market, and the approach would be to mitigate or to replace the entrant's bid by another offer, with a minimum to that offer. And what that means in particular is that in the capacity market in that particular auction, if that entrant's bid is being increased to some minimum, that entrant may not clear the market. And part of the rationale, then, is that this could be discouraging that particular sponsored entrant from entering. So that's one type of approach.

The other type of approach--and I don't want to mean that these are vastly different, there was just a small difference that I want to highlight here--the second approach is to think about the market rule response as really correcting the market outcome. So not necessarily preventing the entrant from clearing, but just saying there is an outcome, a price outcome that's too low that's being suppressed by a sponsored entrant to the market, and then the primary intent would be to limit the impact of that sponsored entry on the clearing price. So instead of replacing the entrant's bid, the entrant's bid would be taken to clear that market, but there would be a correction after the fact of the capacity price. For purposes of making that correction, the entrant's offer would be repriced for the purposes of calculating an alternative price, a corrected price for the capacity market.

So let me go into a little bit more detail on that. So those two approaches of either mitigating the entrant's offer or correcting the market outcome, is what I'll be talking about in the next two slides. So the response to the New Jersey law really falls in the first camp. And here I'm going to really just go after a few of the details of the response or that proposal for a change in the rules. It's asking for mitigating the offer from sponsoring capacity, so changing the bid upward to prevent the suppression of prices, and continuing to mitigate that resource forward until that resource has cleared two auctions. And what that means, again, is that in that context the sponsored entrant may not clear the auction.

What's the effect of that rule, and why does it deal with the sponsored entry? Well, the effect of that rule is to increase the cost to the sponsor--that is, the sponsored resource may not get the capacity payments. The new entrant may not clear the market, may not get the capacity payment, and the intent here is that then it may discourage that kind of entry. And then the goal of suppressing the capacity prices going forward is not successful either, because the offer is being increased, and therefore the sponsored entrant would not be depressing the capacity clearing price. So that type of rule would clearly most achieve its objective if that rule did succeed in preventing entry. So it increases the cost to the sponsor sufficiently that it's just not worth sponsoring entry in that way.

I guess a question kind of remains about the effectiveness of the rule in question, that is, whether the incentives to sponsors are fully removed by that rule. Certainly we know that they increased the cost of sponsoring entry, but the sponsor may have other objectives that they view as being worth the cost that's imposed by that mitigation, whether it's having a particular type of resource, whether it's reliability, whatever the goals are in addition to suppressing the price. The sponsor may think that they're still worth the cost that's imposed by that mitigation. And there is an issue if the sponsored resource does go ahead. If the rule's in place, but the sponsored resource, the entry that's being sponsored, does go ahead and is built, then it means that if that resource is being priced at a higher level for the purposes of the auction, then the capacity clearing price would be set as if the sponsored entry did not occur. But it does occur. So in a way, the market is long, but that signal is not necessarily given to the market.

I'm going to contrast that quickly with the ISO New England proposal, which takes the second approach. So in their proposal, the auction is cleared using the offers from the entrants, whether they're sponsored or not. The sponsored entrant then can clear the auction, and capacity clearing price is established. That capacity clearing price, given that the sponsored entrants may bid very low, is or can be suppressed, and an alternative clearing price is calculated then. So if you want, a "but for" price is calculated of how the auction would have cleared but for the fact that the entrant is sponsored and is pricing at a lower level. Then the new resources receive that lower capacity clearing price, but existing resources that would have entered without being able, necessarily, to predict that sponsored entry receive that "but for" or alternative capacity price.

So very quickly, the way it looks is, if you imagine all of the resources and all of their bids being this aggregate supply curve that you see in black (on the slide), and given a certain amount of an ICR [Installed Capacity Requirement], there is going to be a capacity clearing price that's established. So that takes the bids of the sponsored entrants as they are submitted by the sponsored entrants to establish a capacity clearing price.

For the purposes of calculating the "but for" price, the out of market resources or the sponsored entrants are being repriced, and a new price is getting calculated, which is the alternative capacity price. That's the price that would be provided to existing resources, while the capacity clearing price would be provided to new resources. The resources that are kind of what we call in between do receive the alternative capacity price as well. So that's kind of graphically how it works.

So this second approach in a way is kind of a more modest goal in the sense that I see the first approach as saying, well, the offers are going to be mitigated, and presumably that will serve to prevent that sponsored entry from occurring. The second approach in a way corrects the market outcome rather than saying that it's going to prevent entry from occurring. In a way it's saying, "Well, entry may occur anyway. Let's just make sure that the impact on the capacity price is corrected." It does provide a disincentive to entry because it means that this sponsored entry does not accomplish the suppression of prices. But the emphasis is not so much on preventing that sponsored entry as in correcting the market impact after the fact. Now, that correction to price with the ISO New England proposal is maintained over time.

Now, both approaches have pros and cons. The first approach in a way puts all its eggs in a basket of preventing that sponsored entry. If it does, it's great, and it has accomplished its goal. But if it doesn't, there is a possibility that the sponsored entry does enter, but also duplicative resources also entered on the basis of the capacity price that's established when mitigating or pricing up the sponsored entry, while the second approach in some sense accepts that the sponsored entry may occur and really tries to deal with correcting the price after the fact.

Of course, a last note, when we're talking about all this, we're really only talking about how both approaches affect one payment component in the capacity markets. We're not talking about what would happen on the energy market side and any of the other impacts that sponsored entry or the corrections can have. That's it.

Question: Unless I'm missing something, if you can just take this sort of one step beyond in terms of the two approaches, what the impact is on what customers pay under the two approaches? Because as I listen to your description of the New England ISO, it struck me that what consumers end up paying for capacity is substantially more than they might otherwise pay under a different scenario. But I may have missed something, so maybe you can clarify that.

Speaker 3: If you just take for a second the assumption that the way you're going to reprice the resources in the two cases is the same, in that case, I wouldn't agree, because you would basically be getting to the same price in the end, the same. So the alternative "but for" price would be the price that would be when the new resources are being repriced with a minimum bid. In the New England scenario, you would be paying all of the new resources a lower price than that, that is the actual clearing price from the auction when the sponsored entry is not being repriced. So that would be a lower price for all of the resources. For existing resources, you would be paying the same price. And the difference between the two is that ISO New England would potentially be purchasing a little more. So the effect is ambiguous, actually, because on some portion you pay less. On some portion you pay the same. But you may pay for a little more resources than in the other case.

Question: As a quick aside, I agree completely. We did some empirical work that's in front of FERC in the filing, and you can't conclude. It depends on the distribution and shape of things in the supply curve.

Question: Is there some underlying assumption here that for whatever objectives that are driving the subsidy, whether it's reliability, environmental, whatever, that these are quantifiable, measureable benefits? So you can do an ex-post analysis and determine after the fact that whatever higher prices is being paid are offset by benefits to consumers, or conversely, at some point the benefits are immeasurable, and you're paying considerably higher prices without any consumer benefit? What is the underlying assumption here with regard to quantification of benefit?

Speaker 3: In the approach here, there is really no such assumption being made. I'm trying to be very agnostic here, actually, and say, "States may have their own reasons to sponsor generation or sponsor entry in capacity markets, and whatever calculus they're making to come to that decision, we're not taking that into consideration here." So in the New England approach, in the sense that the assumption of their approach is to say, "entry may occur anyway, what do we do in terms of correcting the impact on the capacity market price?" I think that if in considering that certain changes to the market rule may be preventing entry and may be sufficient to prevent entry, then I think one is making the assumption that you're imposing a cost on the sponsor by changing the market rule, and that cost is going to be sufficient to make it sufficiently costly that the state would say, "No. If it's true that we're not going to get a capacity payment at all, if it's true that it's not going to happen, then we're not willing to kind of go ahead under those conditions."

Question: In both cases, there is a presumption that there is some exogenous motivation for doing this, OK, and so who knows what it is. And neither, if you think about it, neither approach attempts to prevent the state or a third party, or anyone from engaging in that behavior. They both tend to have two different approaches to isolate the price impact on the rest of the market. OK? And depending on how you implement it and the shape of the supply curve and the exact rules, the exact cost to people of doing that are going to change, and the tools are slightly different, and they create the in between stuff. It creates some ambiguous pricing about when the efficiency of retiring, with the New England approach, the PJM approach and New York's approach is a little more zero-one. So it has a little more efficiency on one side, but it may be deemed a little more aggressive with respect to the way it complements a state's individual choices, although both of them don't prevent a state choice. They just change the cost.

Speaker 2: I think we all agree that states may have numerous objectives for building capacity and that whether the legislature makes a good decision or a bad decision is their own option. What's remarkable to me is to be sitting here with purported free market economists talking about how to correct the impact on the price when the state takes an action to build capacity. That sounds more like a price fixing meeting to me than a meeting of free market economists trying to figure out how to design the best possible market.

Question: I have a purely mechanical question about the ISO New England approach. And that is, is there a disequilibrium problem where you actually have resources at the new price that don't clear because you have this sponsored resource? And then what is done about that?

In the ISO New England approach, when you reset the price as if the sponsored resource had offered in at its, for lack of a better term, true cost, is there a situation where you actually have resources that don't clear in the capacity auction that would have otherwise cleared at the new price? And so that's a disequilibrium problem? And how is that dealt with in ISO New England?

Speaker 3: Yeah, I think you're talking about what's called the kind of "in between" resources and the in between resources are under the proposal, given the "but for" price, if they're clearing in that middle.

Question: So then you would actually have more capacity clearing than you otherwise would be optimally. OK.

Speaker 3: Right.

Speaker 4.

A couple of first things. One, as usual, this is me. It doesn't reflect anything from my clients. They may agree, and they may not. Second, I took the question at its word with respect to the term "existential," so I tried to make this a little more abstract. And part of that was the result of a concern of their potentially being decisional staff here, and I think I'm correct that there aren't, because there's an open FERC doc that's about this. But if this creates an embarrassment for anybody, raise your hand, or you can leave, or whatever's appropriate. But I don't want to do that, and I think our discussions, as you can see already, are probably going to overlap into two dockets at least that are open in front of the Commission.

A couple of quick side things. I've done testimony with respect to solutions in both New England and in PJM, and going through those alternatives, and we can talk about it later, I think I have a slight preference for the solution, the style that is in PJM or New York, which is your number one, but we can talk about that.

A third general concept that I think is really important, because as Speaker 2 implies, we don't agree much about any of this, is that there are a couple of underlying precedents in both, I think, economics, and then fortunately in the Commission, is that in these markets, a megawatt is a megawatt is a megawatt if it's located in the same place. It doesn't matter if it's old or new or in between. To the extent it's in the market, its contribution to reliability when adjusted for outages, etc., is the same, and there is not fundamentally in a market mechanism--because I do agree with him that we have created this—but in a market-like mechanism, there is no basis for discrimination. And it's a fundamental, philosophical view that we're going to come back to over and over again.

In that context, I chose to be a little more abstract, and so I really believe the title. I think we all know the paradigm, I'll go through it quickly. There is a mandatory exogenous reliability requirement in capped energy. And in those circumstances, the most simple-minded view is, "I have a new peaker. It's sitting there just for reliability. It runs like once every ten years. When it does run, it sets a price in the market, never has any infra-marginal rents. Who pays for it?" So we need something. If we're going to have reliability as an input, not as an output, but if reliability is going to be a mandated input, then there needs to be another source of funds.

And it's a fundamental difference to have reliability as an input. All the other markets we talk in general about reliability or the quality and the quantity in the marketplace, but that equilibrium notion that we see is an output of market behavior. And in our markets for electricity in general--and I think it's actually federal law--the reliability is an input. I know we're going to argue about that, too. But it is an input. Essentially, we need a way to come back with it. I've always termed it the "missing money."

Capacity markets are a tool. Speaker 2 and I both agree on this. They are a tool. They are a market-like mechanism, not exactly a market, but a market-like mechanism--or if you wish, you can think about it as a control mechanism in which to reinstate the money that we effectively have made impossible to recover because of excess supply in terms of a mandated reliability or because of price gaps. Both of those work to do the same thing, and you have to somehow undo that. And we're looking for an efficient means of doing it.

And we have cost-of-service regulation. If somebody wants to go back and condemn all the existing generation, and buy it back at a fair price, we can go to cost-of-service. That would work, too. But you've got to make a pick, and within the world we're working in now, the basic paradigm is to do that through a market mechanism-like capacity.

The complication in this is, that like most market mechanisms, we are subject to the exercise of market power. We've been talking mostly about buyer market power. Seller market power is just as problematic. It needs to be watched just as much. These are hugely concentrated markets on both sides. We have in several of the markets administratively-set demand curves, which are effectively the control tool. They're the thing that speeds the damping mechanism for hopeful convergence towards equilibrium reliability standards. And they're very steep. PJM, in the middle of the curve, is 20 to one. So small changes in physical withholding or excess supply result in very big changes in price, in total payments. And it's true on both sides of the coin.

What's the hot topic today? You've seen snippets of it in the discussion, and it's the fact that uneconomic entry, because of this, can drive down prices for all market buyers. And obviously, the price is received by all market sellers. Where the curves are this steep--and in PJM, it's at 20 to one—the effects are significant.

A simple example. I used $140 for the RTO, that's just a rough ballpark number. The equilibrium price for a peaker is in the ballpark of net price. That's net of expected energy and ancillary service. So that's in the ballpark of $250 a megawatt day. So a 1% change in the output of the total pool of resources competing when there is a demand curve can shift prices from $250 to $200. For the individual plant, it would be a payment in a year of $128 million. If you looked at it across the whole footprint--which is totally possible, we don't have to have constrained LBAs--the price suppression is $2 ½ billion in a year. These are enormous sums. The temptation is overwhelming, and they are perceived [as savings]--although they are truly transfers. We can get into some of the welfare stuff, but I view them as 100% transfers, because demand curves are really proxies for a vertical demand curve, and so in the abstract, these are 100% transfers of wealth. They have nothing to do with efficiency. It's just the exercise of market power one way or the other.

The savings aren't real. I think I just went through that. And when we talk about creating artificial stimulus in markets and price suppression, I've always sort of felt like I was talking in the abstract—"Well, you guys realize when you do this, you're going to make it more costly for people to come in. Capital will be reluctant to invest in markets that can be manipulated. Every new resource eventually becomes an old resource. It all becomes subject to being taken advantage of. So whether you realize it or not, eventually the prices will go up."

Well, we're getting really fast [in terms of the market feedback loop]. I mean, Brian Chin was mentioned. I spent two hours or three hours on the phone with him with respect to the New Jersey activity. And the same day, actually earlier in the day, on which the Governor signed the bill, Moody's, not him, but Moody's, put the New Jersey suppliers and people who had supplies that were sold within PJM markets on negative credit watch. So the manipulation in the market instantly turns into potential higher real costs for the next tier or people who are going to be building. Anybody responding to the New Jersey RFP or the Maryland RFP is going to be paying more for money. It's just that simple. It happened overnight. I don't know if it was satisfying, but I've always seen this feedback look at sort of slow, and here it actually accelerated the action.

But even with that in mind, for the people that are signing the checks, the people who see the bill the next day (as opposed to those who see the misallocation of social benefits, the mispricing of power, the overconsumption of power, the overconsumption of assets in terms of being put into the power generation business) they don't see that. What they see is the politics of "What's my next bill?" And these kinds of numbers, where you spend $100 million, and you're looking at $2 ½ billion in price suppression, are enormously tempting, and they're a powerful incentive for out-of-market subsidies.

The states and local government, but principally the states, play a key role in this. If you exercise this kind of market power on your own, it still works. If I have a large market share, I can still suppress prices and drop my cost, but where we have contestable sales, contestable retail structures, the guy next door to me, who's also, say, competing in the BGS or New Jersey or is competing for the power at some paper mill or something like that, he gets the lower price, but he didn't buy the full-priced unit that was used to suppress the market price. So his average cost is lower than mine. If I'm the party engaging in the exercise of market power, my average cost is higher, because I get some of my supply at the cheaper suppressed price, but some I paid, quote, "full price" for in order to increase the overall uneconomic supply. That's not a winning strategy. And very quickly, if you start looking at the numbers, this becomes a losing strategy, unless, and this is a big unless, I have a way to pass that on to a third party, or perhaps, as in New Jersey, lots of third parties--like everybody in the state with a non-bypassable charge.

So who generally can do this? It's the state. It's the regulatory authorities. And so the winning combination for buyer market power is a combination of price suppression through uneconomic entry--effectively a form of price discrimination--and then a partner that makes you able to tax third parties through their utility bills, through the general fund, it doesn't really matter. It's that administrative authority to take it out of somebody else's pocket.

Is a little subsidy OK? We see the big picture, and the abstraction is, this is a bad thing to do. Price discrimination is bad. It's hard to justify in the abstract. But maybe a little is OK. I mean, I think that's the existential notion here. Can I fool around a little at the ends to achieve social goals? And so maybe it falls into the notion of solar and wind and local REC programs by the states. Might that be acceptable? New Jersey clearly, as part of it, was motivated by an employment issue. Maybe I need jobs in my state. That's a good social objective. What about demand response? Can I subsidize demand response? And as we all know, particularly--I'm out of Washington now, but I still go back--it is a slippery slope. We don't know where it ends. And typically it never ends at a good place. Who decides? Where does the decision get made? Who has the authority for quantity?

In New Jersey the number was 1,500MW, 1,000MW, 1,400MW then 2,000MW, or something in the middle. And it wasn't batted around by analysis. It was batted around by the process--everybody got what they wanted, and the Governor wanted some more. At least that's my understanding. There isn't a logical end point once you get into this game.

And the numbers are huge. As a snapshot, PJM is doing scenario analysis for potential transmission planning. I pulled the numbers of what they are projecting in response to the state programs--not natural market entry--but what do they think for 2026? Nominal megawatts, 52,000 megawatts nominal of solar and wind. 10,300 megawatts of UCAP equivalent. You know, that's derating by the effective output of the plants on peak. And that's over 5% of the market. 5% of the market, if we were looking at it in a single year, essentially sinks the ship.

Now, it's not all going to come in at once. But it's there as excess to the extent it is subsidized through other programs. And it is not the dog, with this being the tail--it has become the dog. The rest of the market, the residual participants are the ones getting whipped around by the prices for these kinds of activities.

It's not to say that the states can't or shouldn't do this. I mean, they absolutely are free to express any desire they want in terms of social objectives that come out of their pockets and don't overstep the federal jurisdictional market pricing. And if they want more quantity, they can have more quantity. They want specific quantity, they can have specific quantity. Environmental is not as clear to me as where the laws cut in between, but if they want cleaner, they can have cleaner.

What you can't have in this is, "I'll do it, and by the way, it destroys this control mechanism of setting price for everybody else." If you allow that, the only rational expectation is that we'll have five different new backstops proposed. And so at those targets, we have to average the cost of new entry. If we're running in excess of those all the time, because of all these other activities that are deemed a little bit socially desirable, the average recovery is never going to equal the average needed to stay in the market. And no one's ever going to invest in that. I mean, as a private investor seeing a market where the average expected revenue is less than I need to average over time to come out, they just simply won't invest. You might as well stop the market.

Is a little bit [of market subsidy] OK? A lot, we know, is transparently horrible. A little is just as bad. I refer to it as a slow-motion train wreck. If I know I'm going to get 90% of what I need in a theoretical notion over time, I'm not going to invest. If I know I'm going to get 50%, I'm not going to invest. The interesting phenomenon is that the beneficiaries of getting close but still being low are the incumbents, because you increase the rents, payments and transfers that are moving among parties without getting the benefit of what we're ultimately looking for, which is market-based entry. And so being just short of the right amount is actually the worst possible solution. It's just a question of, you know, again, I look at it as a control mechanism. The closer you come to right, but still being wrong, the longer it takes to fail, but it will still fail.

One last comment. What does this mean? If it does mean you fail, what happens? You can't persist in a world where there's price discrimination. It's not sustainable. There will be only new entry via contract. And then all the new contracts, be they for pet programs, renewables, or just simply because we need them because no one else will build, they become the dog, and then the residual existing supply becomes the tail. And then we're presented with the problem of how do you compensate the tail? Do you make up the numbers? Do we return to cost-of-service rate making for them? Do we condemn them and take them away? Somehow, you've got to do that.

We haven't been forced to confront that yet. We've only confronted it on the reliability side with RMR (reliability-must-run) contracts. But collectively we need to think about it for the market as a whole. And so this isn't a riskless game in terms of what you do in the short run. We have a long term, and it still may be the tail, but there's a lot of generation out there that is going to be artificially priced for a long time, and the artificial pricing that comes out of this kind of manipulation in the capacity markets is hard to ever see as being just and reasonable, unless we set the prices right in the market. Thank you.

Question: There's something I didn't understand about your discussion of "is a little subsidy

OK?" You said, the perverse result of a little bit of subsidy is that the slower the degradation, the more info marginal payments are made to existing supply. It seems to me, and I think you agreed, that New Jersey or whomever could continue subsidizing. That's their own prerogative somehow, albeit misguided, we might agree. If that produces enough capacity to depress the price below what is needed for new entry, we don't need new entry, right? Because they're putting in enough.

Speaker 4: Right.

Question: So what's the problem?

Speaker 4: Well, the problem is, is that we have a price that's not indicative of the control mechanism. So we may be overcompensating the existing folks. We may be undercompensating.

Question: But didn't we just do, didn't we agree, or didn't you point out that that would be below the average requirement for net new entry. Right?

Speaker 4: Right. And so there is no new entry. It's only going to come via out-of-market activities.

Question: But that's still new entry, and it still means we have enough in the market in total.

Speaker 4: Oh, yeah. So if you're relying on a market tool to create new entry, it's gone. So but now the question is --

Question: OK, that's fair enough.

Speaker 4: We're making up a price for everybody else. And those people get to make up the price by the manner in which they create the out-of-market entry, because for all of us that have demand curves, somebody simply says, absent of rules, we're talking about, well, I think they ought to be here. And someone says, oh, no, I think we ought to be here. And they can control that by this out-of-market entry. We're not going to be unreliable. I trust that there will be 50 ways that somebody is going to say, "Ah, we need a back stop. We need an RMR, or something's going to happen." The issue is, what's the right compensation for the other participants? And now it just simply becomes, let's make up a price based on the size of which we do this.

Question: But it would seem to be a lower compensation than what would otherwise have obtained if we didn't have this subsidy.

Speaker 4: Sure. If you exercise market power, depending on which side you are. If you're on the buyer side, you can't stop the market power if it's there. You can try and mitigate. So if you're on the buyer side, it will depress prices, and if you're on the seller side, it will increase prices. That's sort of why we call it market power.

Question: I guess I'm a little confused by your inclusion of RECs as a subsidy. And in particular, I guess it strikes me that RECs are a separate product, much like a carbon allowance of an SO2 allowance would be a separate product. And are you suggesting that we ought to eliminate the SO2 market, for example, in order to maintain RPM? I'm confused about where you're drawing the line between a subsidy and a separate good that is pursuing a different objective.

Speaker 4: It's a real fair question, and the only answer that I have been able to come up with that I think works is that if it is a federal national program, and available on that basis, it's real, and we have to build it into the overall value that we give to resources. When it is one state saying, I'm going to force this kind of supply, and it goes with it, the REC creates, it may be a separate process, but it is an indirect form of subsidy.

Question: So it's not good enough if you have 13 out of 14 states in PJM with REC markets, that's not good enough in your view?

Speaker 4: If it was federal, I'd say I'm still not happy, but I guess I go along with it. The issue isn't that you can't have the program, and it isn't that you can't get the quantities you want. You could. And you can. And to the extent you think it's appropriate in your job that you should do that, you ought to. But the question is, in pursuing that as a set of state policies, as individual policies in a federal jurisdictional market, you get to help influence the prices in a fashion that's different from the, I don't want to say competitive, from the controlled norm that we think is appropriate. And that's the debate.

Question: And I guess I think that's part of my job to influence those prices in a positive way.

Speaker 4: And certainly you and I aren't going to do it, and I think FERC and the courts are going to do it, and you, obviously, directly. And I think that's a fair debate. I come at it from a different perspective. There is absolutely no reason why a state regulator shouldn't have that perspective. You should. And I think that's what the courts have been arguing about for a long time about this.

Moderator: If I had a gavel I would tap it right now. We have one more clarifying question, and we'll have more of this after the break, I'm sure. It's a good discussion.

Question: We talked a lot about subsidy. Could you please explain what you mean by subsidy, and what are the elements in the subsidy? And have you done, as economists, the study to compare this subsidy and the benefits of the market, versus the subsidy? And why is it in the public interest in order to develop a market, versus subsidizing for the needs that the market has?

Speaker 4: Well, two things. Somewhere I have written, and certainly I know we have in briefs a really good definition of subsidy, but it's basically out-of-market payments that are not otherwise available to general market participants. And there's all sorts of little nuances that you try and --

Question: Could you translate this into English? [LAUGHTER]

Speaker 4: New Jersey said, build a new plant in New Jersey, and you put it in the district--it's not that explicit--but you put it in the district of the president of the Senate, and you happen to use the labor unions that are in that district, we're going to pay you a minimum of $230 a megawatt day, regardless of what the market price is.

Comment: Actually, it was an RFP, but the price was set through the RFP process.

Speaker 4: No, originally it wasn't.

Question: Originally it wasn't, but then they changed that.

Speaker 4: And now it's changed.

Question: We agree that was an improvement.

Speaker 4: The point was, is there is no reliability problem. There is no other need. For whatever the objective function was, be it jobs, be is price suppression, we all have our opinion about it, that was a megawatt that was existing right next door, as the Commission repeatedly says, a megawatt is a megawatt is a megawatt, was ineligible to receive that.

Question: But you act as if it was to the Senate president's brother-in-law. It was open to anyone who wanted to participate in the RFP.

Comment: We can talk about that more after the coffee break, because that's not true.

Speaker 4: The second part of the question is, the benefits, I think you and I probably different on benefits. Price suppression by uneconomic entry is not a benefit. It is a transfer. It has no welfare benefits at all. It's no more a benefit than someone who, by withholding supply, raises prices, is benefiting suppliers.

Moderator: This is a good discussion, and I think that right after the break we should give all the panelists the chance to answer that same question, "What do you mean by subsidy?" because we're throwing the S word around here a lot, and it would be good to know what everybody means when they say that.

…This reminds me of a very early conference that I attended on restructuring. I was at a Cornell engineering event of all things, more of an alumni thing, but it was a very exciting meeting. And Dick Schuyler, who is an economist and an engineer, and is on the board of the New York ISO, asked the question to the audience. He said, one of our jobs (this is before any of it was defined) is to decide when is the market working? So he threw it open to the audience, and he said, when can you tell when the market's not working? And some eager beaver's rocket arm went up, and he said, "It's when somebody's making a lot of money." And somebody else said, "No. It's when somebody *else* is making a lot of money." [LAUGHTER]

General Discussion

Moderator: We're going to start where we left off. We're going to let the other panelists besides Speaker 4 answer the subsidy question, and then we'll turn it open to the general audience. So why don't we just start with Speaker 2. How would you define the term subsidy, since we're all using that word?

Speaker 2: I would define a subsidy as a payment from a public entity that makes up for the difference between the cost of something that the public entity determines to be in the public interest for reasons that are not necessarily reflected in the market, and the market revenues that that resource would get. So I do agree that New Jersey is offering a subsidy. I think it's a market-based subsidy, because it's open to any entity that wants to compete for that RFP, and it recognizes the benefits that the market is unable to produce directly. I think that RPM is also a subsidy, because it similarly is designed to make up for inadequate revenues in the energy market for certain resources. It just turns out that RPM is a much, much more expensive way for consumers to yield the benefits of that subsidy than direct investment by the states.

Moderator: Speaker 3?

Speaker 3: When I've been using "subsidy," I've been using it to mean just something over and above what the market offers, and here we're talking about what the capacity market offers, and I think that to go off some of what we've seen in the other presentations, the idea of having a subsidy is usually linked to the fact that the entry that is being sponsored would not otherwise be economic. It needs that extra, over and above what the market can provide it, which to put it another way means that if that resource were to compete in the market, it would not succeed. It would not clear the market. For example, the plant cannot be built with the capacity payment that's being offered by the capacity market. Therefore it needs more. And I think that's why we've been talking about this sponsoring of entry as being uneconomic entry.

But while I have that topic open, and the mike, I will say that the entry in question that is being sponsored, in my mind is not necessarily uneconomic, and actually that point was almost made by the first speaker in saying, "Well, now that New Jersey's actually going to be subsidizing a plant, LS Power has come back and said, well, our costs are actually really low." So I think there is a bit of a game here that could be played in the sense that you could say, "I really need a subsidy. I really can't come in. I need more from the state. I can't survive just on the capacity market. Please, please, please give me money," but in fact that may not be true at all. Who wouldn't go for just a little more money? So I think that when we talk about how the states are therefore sponsoring entry, and that it's uneconomic, and therefore may be inefficient, because it wouldn't survive itself on the market, that may not actually be the case. They may just be giving more money to entry that would come in anyway.

Moderator: Speaker 1.

Speaker 1: In the interest of getting to the discussion, far be it from me as a lawyer to improve on the definition by economists of a subsidy, so I'll agree with what Speaker 4 and Speaker 3 said, and largely with what Speaker 2 said. Obviously in this case it's something that's getting something out of market that's discriminatory and is not available to everybody.

Question: Well, coming from Texas, I quite often at these meetings feel that I'm coming from a parallel universe, so to some extent this morning supports that, because I kind of assumed the discussion would really focus on price suppression due to renewables, as opposed to price suppression due to political things in New Jersey.

Just to sort of indicate the parallel universe that I live in, we have thousands of hours a year now where the energy prices in the West are negative. When our state policy (headed by, I should point out, a governor who does not believe in climate change, but nevertheless supports thousands of megawatts more wind) comes to pass, we're going to get negative prices everywhere, I suspect, for thousands of hours a year. We don't have the luxury of a capacity market to bail out generator investors, but the analog of the prescriptions of Speaker 3, for example, for the capacity market in the energy market would be something like, "Let's adjust the energy prices. Let's just adjust the clearing prices of our energy market." And I kind of wonder what the panelists think about this. Really the clear point is, if we talked about that in the context of energy markets, we'd say, "No way, you're not going to do that." And I don't quite get how it can even be contemplated in the context of the capacity market. But conversely, what do you see coming down the pike for energy markets with greatly increased renewables? And what do the panelists think about that?

Speaker 4: With respect to the capacity structure, I clearly intended to include both renewables and anything with an out-of-market payment. That was the exchange that I had with the Commissioner with respect to state decision-making on that.

The energy markets are tougher. In terms of the way we have tried to structure things that we haven't dealt with, negative margins have energy and ancillary service offsets. So the reference curves are set and adjusted for incomes out of the energy markets. So as that drops, the curves go up, in the abstract, to the cost of pure capacity.

Now, here we have, at least for the PTC (production tax credit), we have a national program. So let's ignore REC for a moment, so we don't argue about that. Let's just say it was the PTC. We'd still see prices being driven negative. And in the presence of a national subsidy, that's great. It's the logical result in a reasonably defined capacity market, if that transfers to the East. And it will. I mean, we'll have pockets shortly where we'll see those kinds of negative pricing in the East. The capacity price will effectively equilibrate at the cost of pure capacity for conventional generation for a peaker. And if you think about it, it depends on the very specific mitigation programs that have been proposed. I think it works. And this is, I think, where we draw the line of getting into the detailed cases, which probably isn't fair, but in the abstract there are proposals on the table that I think would adjust for that.

Question: So what happens in a non-capacity market?

Speaker 4: In a non-capacity market, you're going to see more retirements in RMR. It's the tail and the dog issue. At some stage you say, "Well, if I'm going to wind up doing that for everybody, maybe I've done something wrong." And then there's constitutional issues about whether it's a "taking." I think that's also part of the issues between federal and state, and I think these all go to legal issues that are a notch above me.

Speaker 2: I'd like to address that as well. I think your question is exactly on point, and since I first heard about the RPM proposal in what, 2005 or so, I've wondered why, if we really believe in this construct, why doesn't PJM just set the price? There's an obvious target price for RPM. Why pretend there's a market? We could save ourselves a lot of trouble. I mean, I suppose it wouldn't be so good for consultants and economists, but basically, there's a target price, and folks who are projecting capacity prices in the RPM market basically use that price. I mean, that's what it's all about.

And we don't like to do that. So if we don't want to actually just set a price, we should have a market and allow the price to fluctuate based on the available supply and not decide that some supply, because of where it came from, shouldn't be eligible to participate on the basis of its going-forward cost.

Question: To Speaker 4's point earlier, since we have a 205 proceeding before the Commission, I'm going to try to avoid a lot of those issues in my comments and my questions here. And I really would like to address some of the issues that Speaker 2 brought up in his comments. I'm struck by the tone of the comments towards certain members of the economics profession with regard to data, as a PhD economist myself, and yet your comments were devoid of any data supporting your position. So let me provide some data supporting mine with respect to capacity markets.

Since the implementation of RPM, we have had available more than 33,000 megawatts of capacity resources that would otherwise have not been there. Of those, we have 14,000 megawatts on the demand side, both in DR and energy efficiency, which probably would not have been in existence had RPM or any other capacity construct similar to it not been able to monetize the value of demand response and energy efficiency. We've also been able to retain existing resources that may have otherwise retired. Of those, we're talking about withdrawing retirements of about 3,000 megawatts. Generation uprates of existing resources of about 4,700 megawatts. 6,400 megawatts, approximately, of actually new generation that's been made available to PJM. More capacity imports of about 4,700 megawatts. So again, we're seeing resources that are made available that may otherwise not have been available in these capacity constructs. So I think it's important to go back to Speaker 4's point about what's the distinction? Why are we making the distinction between old and new? It reminds me of some of discussions of "old gas" versus "new gas." Here we go again. It's sort of the same thing. Except now it's "old capacity" versus "new capacity." What we're really trying to do is retain capacity to meet reliability targets. It doesn't matter what kind of capacity it is at this point.

Another issue that I wanted to bring up, and this is really a question, is that I keep hearing this complaint about capacity markets in general being these administrative constructs. They're sort of an aberration to markets. But yet, by my definition, a market is any arrangement that brings together buyers and sellers. And so do we also then object to markets, such as the SO2 trading program, which were created to solve an externality problem, or potentially to cap and trade for climate change? Those are just as administrative and just as created as RPM. Those must also be bad, then, by that definition, because they're so administratively determined. And so I'd like to get some reaction to that last question. Thanks.

Speaker 2: If I can just start. First of all, I'd like to say, some of my best friends are economists, and I count some of the people in this room as friends, and if folks aren't my friends, I'd like to work on that as well, including Speaker 4. We'll get along fine.

In terms of the data that you cite, you know, it's always very hard to go back and say, why something happened that happened. I think it's important to go back and pick it apart. Nuclear uprates, for example, I would say there's absolutely no justification for crediting the capacity market for nuclear uprates when clearly those are justified on an energy basis. I think there has absolutely been support for demand resources from the capacity markets, so that's been crucial. But again, as I said in my remarks, those could have been achieved by just directing the utilities to pay adequate compensation for demand resources, and it would have been much, much less expensive than going through a capacity market construct that rewards every megawatt equally in the market. And finally, on the question of discrimination, Speaker 4 predicated his comments by saying a megawatt is a megawatt is a megawatt, and there's no basis for discrimination. I tend to agree. I think that means every resource, at least in the current construct, should be allowed to bid into the market at its going-forward cost. If that going-forward cost reflects some public subsidy, then guess what, most of the resources that exist in the markets in the United States have some kind of public subsidy under them, perhaps all.

Question: I guess I had a two-part question. The first one was to Speaker 1 in regards to LS Power. I thought that was quite interesting that they would file with FERC saying that their cost is a lot lower than what a typical new entry is. And I guess my question is, that's perfectly fine if then they can go into the New Jersey auction and bid at a very, very low price. Nobody's going to object to that. But you can't go to FERC and say, "Oh, my cost is really low, and even though I'm going to get this contract at some market price, I get to bid at a really low price in the auction." So--just kind of reactions to that.

And the other question I had is, it's not clear to me why New Jersey didn't go with the option that PJM provides, it's the FRR, which is the fixed resource requirement. So to the extent that they do not like the PJM capacity markets, they can take the whole load out and make the utilities just contract for capacity. And the way I see what they've done is just like mixing both of those two options together. So the vast majority of the load will be still benefiting from the RPM market, yet 2,000 megawatts is going to have a side contract, and they could have just done that all through the FRR option, and so I'm just hoping that the panelists can comment on that.

Speaker 1: Those are good points, and others know some of these details better than I do. But you hit on a good point, and several of us were talking about it at the break, and this goes to something Speaker 2 said earlier--It's not as if states don't have options to address this. And you touched on one. There's another that you also briefly touched on. Both of these are outlined by the Independent Market Monitor from PJM in the filing in Maryland, and as you say, one would be the fixed resource requirement, and the other would be actually requiring them to bid whatever it is they actually…so if you had the state RFP process, then whatever the price was from that state process would then be bid into the RPM.

And clearly that's not what they wanted to do. If you just go back to when the bill was introduced, if you read the preamble of the legislation back in October, as well as the legislative debate that many of us were present for in the state, and to a similar extent with a little more elegant phrasing in Maryland, it's not that they decided--in the case of Maryland, they've expressly said they haven't decided--that they need the resource. Having spent time in Annapolis, too, there just seems to be this view that these are states, as Speaker 2 knows and other people in the room know, which fought this from the beginning, went to court, lost at FERC, and lost in the courts. But, so instead of saying, "OK, let's come up with a change in the rules for everybody, and do it constructively," and PJM has offered some proposals, the market monitor has, FERC has this under consideration for PJM and New England. Instead of doing that, it's been this kind of response like, throw the hand grenade in to blow it up.

The interesting thing about the LS filing, is that it's all confidential. And so they have wanted to restrict the access to the data to PJM, the market monitor, and to FERC. So the states don't get to see it. Nobody else gets to see it. And again, I hesitate to point at a specific company. It's just odd to me, having talked to them at the beginning of the process, and again, having been there and testified with their witness, to go from telling the legislature, "We need this because the price doesn't support the new entry," to now saying, "We can do it lower." I mean, I'm not the PhD economist, I'm just the dumb lawyer who uses a calculator, but that still doesn't add up to me. But again, that's for the Commission to decide. And you're absolutely right, and Speaker 4 reminded me--if they in fact can show they can do it for less, then under the rules now and proposed, that's fine. But something isn't quite adding up here.

Speaker 4: Actually, the FRR alternative was proposed as part of the filings that went into the FERC case. And the good news is, it's not big enough, but there is a buffer to keep an FRR entity from dabbling too much and messing up the rest of the markets. But if they want a 40% reserve margin in the abstract, and they'll spill over into the other areas. Or if they want all wind, they can do that and not interact with the rest of the markets. And I'd like to see the buffer bigger. And you may remember, I argued very strongly that you can opt out, but if you opt out, you opt out. You don't get to selectively interfere with the market.

I probably have a little bit different view on the confidentiality side. If you just take it out of any context, and simply said, "I want to prove my costs are lower," and presumably there's a black box with the market monitor or FERC, and they say, "Oh, yeah, you're $50 instead of $250," and you put that bid into the auction, I'm not so sure I'm uncomfortable with that being confidential. That process, if somebody says, "I've got a spiffier way to construct or pour concrete," or, "I negotiated a better deal with a turbine manufacture, and I don't want somebody else to understand what I've done," as long as it's legitimate, and as long as it doesn't reflect the out-of-market issue, it doesn't disturb me for somebody to keep it confidential. I mean, we see company-specific data reviewed by the Commission, pretty much all the time in a bid sense, as opposed to a cost-of-service sense. So I'm not troubled by that. I think it's a little bizarre to ask for the subsidy and then say, "Well, never mind, I'm really cheap, having talked you into paying me this high price." But that's a separate issue. That's a sort of a gamesmanship issue.

Question: First of all, I guess I want to thank Speaker 1 and Speaker 4 for making a case for moving rapidly away from capacity markets towards actually trying to price reliability through retail demand response, simply by indicating the instability of the RPM market, where the addition of two units could cost the market $3 billion. That suggests to me that we really ought to be paying much more attention to the metrics in our futures markets and long-term forward contracting, which is actually what would be needed to make substantial capital investments in these markets, and suggests a kind of fundamental flaw with our substitute mechanism here, and you may want to comment on that.

But I have two comments going more to this issue of whether or not there's really buyer's market power here. One is, it strikes me that one way of looking at this--and I'm not familiar with the details of the New Jersey and Maryland statute, but it's what we have the option of doing in Ohio, although an option that I think regulators should be reluctant to exercise for a number of reasons--but if there was a need, and it was demonstrated that the markets weren't producing the needed capacity, one option would be to go out and do an RFP with a contract coming out of that RFP to supply energy and capacity back to the Ohio market. It would seem to me that in that instance, the perfectly natural and efficient participation in the capacity market by the winner of that RFP would be to bid zero and be a price taker because their long-term energy and capacity revenue stream would be guaranteed by a long-term contract extending out beyond the term of the RPM auction. And it strikes me that that's a market outcome. There is no real out-of-market subsidy, and I'm not sure why you would want to impose a minimum offer requirement in the capacity market if this is a person who would be a natural price taker, having that long-term contract for their revenue.

The other question that I would have is, that this is clearly not traditional oligopsony behavior where you have only one or a small number of buyers, and they can threaten not to buy as much and reduce the price that way. This is a different kind of activity, and it strikes me that this is not a sustainable activity. If I'm sitting here in Ohio, and New Jersey and Maryland want to go pay out-of-market subsidies, I'm sitting here saying, "Great. Go do that. Meet all the capacity requirements in the PJM market, and you'll lower the price for my customers," and it strikes me that that is just as unsustainable at a state level as it would be for any existing load-serving entity. So I'm not sure why we're so concerned about this and why we have to have a minimum offer price at all.

Speaker 1: There's three questions, and the answer to the first one is, I wish you were there when we were arguing about the slope of the demand curve, because the steepness of the curve and the truncation of the curve, and the offset of the curve were all much better before compromise. And you can guess which side I was on. So we'll leave that, because negotiations are confidential. But those were issues in negotiation.

Let's assume you chose an FRR option to isolate Ohio, and you had an all-source requirement and didn't distinguish between new and existing, and it was really all-source, so you weren't trying to price discriminate by saying, "I'll buy half now, but everybody has to offer." But say you really had an all-source requirement, then good for you. I mean, I certainly wouldn't object to that. That's sort of all we're asking for here, without the subsidies involved.

In your third question, you ask whether out-of-market subsidies aren't unsustainable. In theory, this is not different from contestable retail load, except I'm less concerned about factories picking up and moving to Ohio, but in the abstract, it would be the same problem. It's a lot stickier, and unfortunately, the slopes of the curve are so steep that the short-term payoffs are very high. Remember, the conclusion at the end is, this is inefficient, so it's bad. OK? But I mean, it does pay at, at least in the short run, to exercise market power, and the slopes are so high that if you get the spillover in Ohio, which you do...well, let's just take New Jersey. I think I remember the numbers better. It was roughly $600 million of price suppression in New Jersey. $2.1 billion total for the market and $600 million in New Jersey. So yes, somebody was getting the other $1.4 billion of benefit. But if the total contract payments were two billion, the annual price suppression within New Jersey alone was $600 or $700 million. So it's like 16 to one or something like that. The payouts are so steep because of the slopes of the curve that it still makes sense. And you see this in the political process. If there is a political decision-maker who is told there's a two-year kind of payback in the suppression, and you want to be governor in two years or three years, and we may damage the seven-year economy of the state or the ten-year economy of the state, again, I have my views about how people make those decisions, and I'm sure you do, too, and it's not surprising. But in the abstract, you're absolutely right. Everything is contestable, and so we would expect everyone to move out of New Jersey and move to Ohio. I mean, that's what you're saying. And at the margin, there's going to be somebody who will actually do that.

Speaker 3: Just a quick comment on the same question. I mean, I think one of your questions was, so what's wrong with bidding zero if I'm getting capacity payments from the state? What's wrong with that is, if you bid zero, you're going to get the clearing price from the market, so you're going to be paid twice, and that's the construct. So I think you're thinking, you bid zero, you get zero, but that's not how it works. It's actually kind of a clearing mechanism in a given zone.

Question: Not if I have a contract for differences. I'm getting --

Speaker 3: All right, OK. My mistake. So the other point that I want to come back to is your thought that if New Jersey is adding capacity, then that's great for customers in Ohio, and therefore makes Ohio less likely to be sponsoring additional capacity. I think that's exactly right and that actually works against the instability that you mentioned in the first part of your question. It would mean that if there is a little bit of it happening in the system, maybe it's as bad as was portrayed by my co-speakers here but it also means that there is less likely to be more of it coming along in other states. Except if you believe that the capacity that's being built in New Jersey really doesn't do any good for your Ohio customers and only if it's in Toledo does it do any good, or if it's in Ohio, for whatever reason. Maybe because it's jobs. Maybe for other reasons, there is an additional preference put on it. So that would be the only kind of caveat I'd put on that.

Comment: Just really quickly, a key predicate to the last question was, <u>if</u> the markets are not producing capacity, and for all the reasons the questioner indicated, that's not been the case. The markets have been producing capacity. Speaker 4 and I both made the point at the state Senate hearing that there should be at least some discussion about these numbers, and there was zero discussion about need. So it's not that the markets weren't producing capacity. They're just not producing capacity of the kind and in the politically relevant places in the two states to produce jobs. And that's a legitimate concern. But it's not like markets weren't producing the capacity, because as everyone knows, and the numbers prove it, there's excess capacity in the market right now.

Question: So would your concern go away if there was a finding of need in the state based upon a state proceeding that said we need capacity in this location? Does that resolve your complaint here, if in fact the market has not produced capacity there?

Comment: It helps to address it, and in fact, that's what we said in Maryland. And to the credit of the Maryland Commission, their process has been much less political, for lack of a better shorthand term, than in New Jersey, and they say in the RFP they put out, they're not going to necessarily move forward. They're saying this is what we're considering, the 1,800 megawatts. And part of the process at a later date would be some kind of evidentiary hearing. Now, they didn't say exactly how it would work, and we might have differences of opinion in the membership under the details. But at least in their case they're looking to see if it's needed as opposed to simply a political process, as Speaker 4 said. The number bounced around, sometimes within the course of a day, and there was no rational discussion about this. I mean, the press coverage was pretty clear this was designed to attract a certain investment in a certain location.

Speaker 1: Again, I don't want to go into the testimony, but we can talk privately. Your scenario, if you think through some of the things I wrote about, is addressed, and I think there is a solution that's consistent with what you would want in what I was proposing. And we can go into that. The notion of demonstrable need should have a positive feedback in the auction itself because of the way we set the demand curve and the entry levels and the prices. But even for longer term, let's say you wanted a new nuclear plant or some sort of coal sequestration program or something like that, in the abstract, if it made sense, there ought to be a way to do that, if there was a demonstrable need, and you could prove it, that it was an economic action to do that.

Moderator: I'm going to move this along. We've had four full questions, and we've chewed up over 30 minutes, and we still have seven flags up.

Question: I'd like to ask a question, really, about the California situation, which is really kind of an extension of the previous question about Texas. But here, to describe what we're looking at, we start with a study that Udi Helman did when he was at the ISO that looked at what's going to happen when in 2012 we have 20% renewables. But if we extrapolate that to what we're looking at in 2020, when we're going to 33% renewables, we're talking about a market in which we're going to see lower capacity prices because of all of this additional renewable power. We're going to see lower energy prices, because of all of this renewable power, participating basically at zero bid price into the energy markets. We're going to see lower volumes of power sold by the flexible fossil generation units. And we're going to see higher costs associated with those units, because they're going to have to be ramping more up and down. On top of all this, we're going to see the need to add new flexible generating units, which will further depress prices in the energy markets, in all likelihood, in order to deal with all the intermittency from this move to renewables. And we don't even have a paradigm by which we're going to get those new resources yet, but presumably we'll develop one. And, like Texas, we don't have a capacity market, so we can't simply make some modifications to the capacity price as a means of dealing with this.

If, in fact, the solution to keeping these existing resources that are needed in the marketplace around is going to be to put them all under RMR contracts, as Speaker 4 suggested might be the

Texas solution, what's really left that the market is doing for us? We have RMR contracts, for the existing flexible generation fleet. We've got long-term contracts for the new resources we need to add for flexibility that are going to have to be controlled by the ISO to get those resources, and we have renewable power that's basically must-take resources in the market. Do we still have a useful market? What purpose is it still serving, if the prices aren't even really controlling much of the dispatch decisions at this point?

Speaker 4: If fundamentally you believe you need to intervene in all of these things because you're not happy with where things will go in a non-discriminatory locational capacity market, then you should be worrying about how do you equitably buy out the existing generators? I mean, that is the conclusion. This is the end game of the slippery slope. It's just a question of where you get there. Now, a lot of people stick their head in the ground and squeeze the existing supplier, maybe appropriately, maybe inappropriately. We can argue about that, whatever. But in some sense, by creating a game where at the end there is no market, you're effectively seizing their assets. And so the fair thing is, we reverse what we did when we had stranded costs, and people sold the assets, and people were unhappy with the sales price. They'll be unhappy with the buy price, and we'll have the whole mess again.

Question: Sounds like fun.

Speaker 2: I largely agree with the premise of your question. I think that a capacity construct that doesn't recognize the differences between flexible generation and low emissions generation in a state that has declared that to be a priority and other generation, simply is not compatible with the objectives of that multi-objective planning process of that state. And I think that's the case for most of the country, certainly on both coasts.

Question: This sort of takes a little further a lot of questions that have been asked. If you view the New Jersey case in a slightly different context, in a positive context, which may be divorced from the reality of the politics of New Jersey, what New Jersey wasn't satisfied with was the price it was producing. So it essentially entered into a kind of hedge contract or proposes to enter into a hedge contract, and Maryland is contemplating that. We've seen that in various phases for various reasons, actually in New England. If that's the case, then the question is, A) aren't capacity contracts constructed in such a way that you can't avoid these kinds of manipulations, because they are artificial constructs to deal with something? And if states are entering into hedge contracts anyway, then why don't we just simply abandon the ghost, and go to a pure energy market? If states don't feel comfortable with the degree of reliability they have, then they can enter into their own hedge arrangements, a la what New Jersey's proposing to do.

Beyond that, the other question, is when have we ever tried energy markets in a lengthy enough process to see if they actually work and produce the results, as opposed to getting paranoid very quickly about the absence of capacity? And that's especially relevant today, given the fact we've got demand-side bidding. We've got tomorrow's panel about opportunities to exploit the retail market in ways (and I don't mean this perversely. I mean this in a positive way) we haven't done to fully mine all the demand side resources. What are we doing with capacity markets anyway? Why don't we just get rid of it, and if states don't feel that they're sufficiently protected for reliability purposes, they can hedge and do what New Jersey's doing or whatever else they want to do to try to do that. So why don't we give up the ghost?

Speaker 1: You're assuming the reason why they did it was because they felt they weren't getting enough capacity, when in fact, again, there's excess capacity, and in a different proceeding, the two states that happened to be pursuing these out-of-market revenue mechanisms--which you're assuming they're doing because they're thinking they don't have enough capacity--in other proceedings that claim that PJM's procuring too much capacity.

Question: No, actually, I'm assuming, you can hedge in either direction. You're correct in the theoretical way of what motivated New Jersey. There may have been other things we haven't talked about. But theoretically, that's correct. But it's still a form of a hedge. It's just a reverse of the way we usually think about hedging, but it's conceptually the same thing.

Speaker 4: Well, if people had a non-discriminatory hedge, I don't think anybody would be complaining. It's the "new only", where it's explicitly designed to exploit the market mechanism. If somebody wants to hedge, nobody's saying anything about not hedging. We have some people here more familiar with BGS, but BGS for New Jersey is, as I understand it, is totally non-discriminatory procurement by the state for whatever tranches, was it rolling three years? But the point is, go ahead and do that. That makes perfect sense. But it also has to look *new*, so it has some of these other impacts that exploit the market design and look like oligopsony behavior.

Question: But they only exploit it because we created this artificial construct called capacity.

Speaker 4: And we did more than the artificial construct called capacity. We have exogenous reliability requirements. We have the one day in ten. We have NERC, we have energy caps. We have 50 failsafes to keep the market from going short on reliability.

Question: But you don't have to do that through a centralized capacity market.

Speaker 2: You know, when we did try energy markets without capacity markets, for example, in this fine state of California, what brought the state to its knees was not the fact that there were high spot electricity prices. What brought the state to its knees in 2000 was the fact that there were high spot prices and no hedging. So I think you're right. Exactly, the key is hedging. You need long-term contracts, and then high price spikes aren't a huge problem. They're merely the economic signal that they're intended to be. Unfortunately--Speaker 4 mentions the BGS auction. That's a three-year construct. A three-year retail obligation is simply not enough of a hedge in order to enter into long-term contracts on the supply side. So there's a basic mismatch. If we had a retail structure that supported long-term contracting, or even mandates for long-term contracting, however you need to do it in order to get that to happen, we wouldn't be having any of the issues that these capacity markets are trying to resolve.

Speaker 1: Yeah, everybody says that, but then are they going to live by the long-term contract? I can guarantee you that if Maryland had signed the long-term contracts when everybody was saying in Maryland they wanted to do that three years ago when gas was $8.00 and $9.00, the same people that were complaining when the rates went up when the rate caps came off will be complaining to get out of the contract. Which is exactly what happened in other states. So this idea that long-term contracts--there's a role for them, but this idea that they're some panacea and there's no risk involved, that's just not true either. I mean, each construct's got pros and cons, but people keep invoking this long-term contract as if there's some room somewhere with a bunch of really smart people that know more than anybody else is going to know and can figure this out, and that's fine, if they're willing to live by the terms of the deal. But that's the problem. People weren't willing to live by the terms of the deal when this was done before.

Speaker 2: Right. And states tend to go overboard one way or the other. I mean, you had Gray Davis saying, "OK, we don't like this short-term thing. Now we're going to buy 100% of everything on ten-year contracts. OK, what's the price?" I mean, obviously that was a terrible response as well.

Speaker 1: But I think what we can agree on is that should be non-discriminatory as opposed to a discriminatory process. I think that's the one thing --

Moderator: OK, I'm going to nudge this along. There's some other people I want to at least pretend like we care what they want to ask us. [LAUGHTER]

Question: How different is this problem or issue that everyone's talking about with Connecticut or New Jersey or Maryland being restructured states from the more general problem in the regional transmission organizations of having some traditionally-regulated utilities being able to build generation, like West Virginia, Virginia, or public power authorities being able to build capacity? Obviously they would have, I would think, a backstop ability to get compensation in the way that pure merchant power plants would not. So is this merely a smaller part of a larger problem or issue in these capacity markets, where you have a mix of regulated and unregulated?

Speaker 4: In the New York rule, as I understand it, those entities, like NYPA (New York Power Authority), going forward, would be included. If you did what I recommended in PJM, they would be included. And they would take the risk for that. Speaker 3 gave two paradigms. This was paradigm one, New York and PJM, and those entities would take the risk of not clearing. So they could go ahead and build it if they legitimately felt they needed it. They would get the reliability benefit. But they may face a potential, if it wasn't economic, of not clearing. In New England, they could do it, depending on how the rules turn out, and they would clear, but then we would reset prices as if they were not there if they were out of market.

Question: I'm from New Jersey and proud of it. [LAUGHTER] Just FYI, what this law is now called is LCAPP, which means long-term capacity agreement pilot program. I didn't know what it was, because they changed it in the last bill, and in executive session, I had to say to staff, what the heck is LCAPP. I didn't know what they were talking about. But that's LCAPP--long term capacity agreement pilot program.

I have a question, but also a couple of points. In defense of New Jersey's commissioners following through on commitments of past commissioners--we do it, we might not like it, but we have non-utility generator contracts that we ratepayers are paying forever on that were signed in the late '80s, and ratepayers are being brutalized by it, but we're still paying it. You have to keep to your commitments. On the other hand, it's not pretty for the people who are sitting there.

Speaker 4 mentioned that if reliability is important, and obviously that's number one, then we need something, either this market thing, or a cost of service market would also work. And I kind of agree, I'm thinking capacity markets aren't necessarily necessary to get to where we're going, so I guess the question is, does MISO have a capacity market?

Comment: We're working on it.

Question: Yeah, well, maybe it's not a good idea. [LAUGHTER]

Speaker 4: But every state in MISO that I am aware of has a requirement for the applicable utilities, right? I mean, they all have reserve margins. Everybody under your jurisdiction that's in MISO has a reserve margin as part of their --

Question: Well, reserve margin is not a capacity market.

Speaker 4: It's not a market, but they have a requirement to maintain certain--one in ten and all that.

Speaker 3: They get the capacity through the regulator saying, you have to have.

Question: Yeah, and it's probably a lot cheaper. Bottom line is we're thinking about what's the best for the customers? That's where utility commissioners come from, and most legislators. So I mean, the issue is, I guess it's two things. What is most cost effective for ratepayers, and obviously you want non-discrimination and all that stuff. There's pros and cons to the way we used to do it, definitely, and there's pros and cons to the current situation. So I guess the question for you guys is between the situation we have now, where we're stuck; secondly, having an energy market but not a capacity market; and third, going back to a cost-of-service market, which as we said would work, too. What are the pros and cons from the ratepayer perspective?

Speaker 4: If you go back five years, somebody will probably keep track and how many billions of dollars of shareholder equity was lost in the bankruptcy of companies like Calpine. OK? It didn't cost ratepayers a penny. And I've been doing this too long. It's over 30 years now. But for at least 20 of them, I used to say (and this unfortunately is a New Jersey joke) is someplace in rate base you guys had some of the floating island expense for the studies, for the nuclear plants off the shore of New Jersey.

Question: I was a staffer then.

Speaker 4: Are they finally out of rate base? Because I'm getting old, so I'm not sure. But that was at least a good line for 20 plus years. So think about that. Now, is either one perfect? Obviously not. The notion of switching was to eliminate the floating islands and to transfer the risk to the shareholders. You know? That paradigm seems to have worked for a lot of venture capital that went in and lost their shirts when the markets collapsed, and it literally did not cost a penny to any rate payer.

Speaker 1: You raise a good question, but from a practical standpoint, representing the suppliers that have made the investment, that have the plants in the ground and are keeping the lights on today, as I said at the top of the opening presentation, this was the number one issue at the annual meeting. These are issues that analysts and potential investors are calling CEOs about today. And we have this wonderful hybrid system of different parts of the country doing different things, and we didn't get much credit for it three years ago, because people assumed we were going to say our version of competition everywhere, come Hell or high water, and that's not actually what we said. I mean, we had Dr. Sue Tierney do a report that frankly--again, we didn't take that much credit for because we said, look, from a practical standpoint, the debate about some of these things, as important as they are, needs to stop or at least be not just debated but implemented in the context of all those broader things that we talked about.

I mean, I would agree with Speaker 2. We've got members that wanted to see things happen on climate change. We all know what's coming from EPA. We all know that there's a lot of investment that needs to happen. And so the thing that should be of concern is the point that Speaker 4 made and that the market monitor made, and the analysts on Wall Street are making, that companies are looking at this in real time and saying, this is affecting, as you said, overnight, credit ratings, stock ratings.

And so at a time when we're being told to invest all this money for both reliability and other public goods, then things like what's happening in these debates at FERC and in the commissions impact the ability of a practical business person to make prudent decisions. And it's going to have the effect, as we tried to document, of making it harder, not easier, and costlier, not less costly. That's the sad truth--we can't seem to get to a point of either pursuing constructive changes for everybody, or making these things work in different parts of the country. We keep re-litigating the same issues over and over and not getting to a place that's conducive to investment. That's what worries our members the most.

Question: Speaker 4 spoke a little bit about the slippery slope of allowing subsidies in the market. I'd like to maybe ask the panel to comment on, what about the slippery slope of trying to keep them out? And I scratched out a few examples. And if these are not subsidies, I'd like to maybe know why not, so I can sort of understand the formulation. What about things like loan guarantees, or tax-favored financing, or maybe favorable financing that cooperatives or public power can get, or state and federal production tax credits for natural gas and coal that may actually be suppressing new entry for alternative resources? You kind of go down the line. Even things like brownfield redevelopment tax credits, or economic development tax abatement. It seems to me that some of these tax mechanisms could create some real subsidies. And frankly it seems that when you start really thinking about it, everybody has their hand in one cookie jar or another. So where does this sort of a subsidy slippery slope stop?

Speaker 2: I could not agree with you more, and I would add, environmental externalities that are not paid for by generators or rate payers but by society as a whole. And I would further add, stranded costs that were paid by rate payers for resources that in the long run have turned out to be extremely profitable. So I think that you could go on and on. It would be a very interesting exercise to try and pick it apart and find out what the real unsubsidized cost is, independent of federal, state, or local incentives or subsidies or anything else that's going into the cost of these resources. I really wonder what you'd come out with. I'm sure we'd all disagree in terms of the value of some of those things. But they are there, and I believe for every resource in the country.

Speaker 1: There is a paradigm, I think, that helps. You're right, this is very confusing. I've thought about this a lot, because you do want to have a reasonable answer to the question, and the line seems to be, if it is a federally-directed subsidy, however it works, and we have federal jurisdiction setting the rates, then it almost is by default a quasi-legal question that says, hey, that's what's going on. It's real. I can't undo it. When you have a federal jurisdictional rate structure for the power, and you have the individual states acting and tugging against what may be the policy set in it, I think that's where the line is. And it may not be satisfying as an abstract notion about where subsidies are or aren't, but I think [the way to think about the question is in terms of] a balance between where the subsidies are and where the jurisdictional questions are being resolved, at least in the abstract.

Question: OK. This is really directed to Speaker 1, and I wanted to see if you could take some time to talk through some of the potential impacts on demand response and what the initiatives you're orchestrated with other enviros has been.

Speaker 1: Some people will have a hard time having me speak for demand response, right? Well, no, seriously. I mean, the coalition actually, and the legislators in Trenton said, "Wow, we've never seen this happen before." I mean, demand response providers were on the letters. We worked with Environment New Jersey, and we actually had meetings with legislators, with the Speaker, with others, all as a group. And they had never seen that happen before, because as the slide from the market monitor pointed out, the impact of this depressing the price--I mean, that's been one of the reasons why you've seen so much demand response in PJM. So we think that's an important part of the conversation. It was an important part of the lobbying. Unfortunately it wasn't enough to change the outcome.

Question: First I just want to make a comment about the earlier idea of having energy-only (not capacity) markets. We did try very briefly in 1998 an energy-only scenario in the Midwest. It lasted about a month before industrial customers, states, consumer advocates, and everyone else went in and said, "You must cap the prices," even though the $6,000 a megawatt hour may have lasted for all of one or two hours. But it did drive a lot of capacity. I think during the RPM --

Comment: That was also before demand response.

Question: I understand. But the point is that I think you've got market monitors who believe that the third tablet that came down said, "Bids shall never exceed $1,000 per megawatt hour." And it is simply incompatible to think you can have an all-energy market if you are going to artificially cap the prices. Because it's very few hours that you actually get that money. And it did incent lots of new capacity in Illinois, probably too much because of the enthusiasm.

I wanted to make another point and maybe get some responses. Some of the earlier discussion did raise some issues about how Pennsylvania's subsidizing new capacity might be good for Ohio. And I want to postulate that you now lower the capacity price lower than it should be. You've got EPA regulations that are going to be issued next month. You now have companies that have to make market-based decisions on whether to invest in control technology, and when they're making those decisions, presumably one of those inputs is their revenue stream, and that includes how much they're going to get from the capacity market.

And I guess I'd like some discussion of this. I'm not sure it's even the specific drop in the capacity price that is going to affect that decision. But the great uncertainty--that you can make a long-term decision on environmental controls, and then [capacity subsidies come into the picture] just all of a sudden--like a crack back block (illegal, by the way)…and so I'd like some discussion on that, because I think [actions taken in] we'll just say New Jersey, which that happens to be where it is, can go over into the Midwest, where they have the coal, and make significant impacts on the fleet in other areas.

Speaker 3: What I was responding to was mostly the fact that if in one state or in one place there is that incentive to sponsor capacity, then I agree it kind of takes it away from somewhere else--"because now we have more capacity, and we're happy with having the additional capacity that otherwise we would have sponsored in Ohio or state X." So I don't think I was saying that we would applaud the suppression of prices that comes from that, and I think that there are properly market rules to kind of address that.

But if I can comment for two seconds on the energy-only idea, I'm a bit struck that the discussion has become, "Well, you know, it's been all of three years, so let's just scrap that idea and do something else already," in the sense that there were capacity markets before the change that meant there were increases in capacity prices for New Jersey and elsewhere. In PJM, for example, there was the move to a forward capacity market. That was not just because of the capped energy prices, but also to provide a mechanism so that there isn't that problem of incenting too much capacity all at once, that there is a signal that is for entry in a three-year forward period. So it strikes me a little bit, because given the forward nature of the capacity market, you don't really expect the price to go to $200 per megawatt day, the plant springs up tomorrow, and the price goes back down the year after. There is kind of a time period that goes along with the forward capacity market that it seems is a bit forgotten in the discussion, when people say, "Well, let's all throw up our hands now and do something different."

Speaker 1: Well, just very briefly, I mean, obviously I agree with the premise of the question, because it builds on what I was trying to say, and for a number of people in the room who were at the NARUC meetings last week, and the at the NARUC DOE electricity forum, this was discussed, and there were all different analysts with different numbers. Is it 20 gigawatts at risk? Is it 100? Where is it? But the point's well taken. If your revenue stream is uncertain as a result of these actions at a time when we're talking about either retrofitting plants that are as old as I am, or replacing them, that's going to have, I would think, a tilt in the direction of making decisions you otherwise wouldn't make potentially to retire or to not invest. So that's why I think the point's well taken at the last slide.

Here we are supposedly motivated, as we talked earlier, supposedly, by a feeling that there's not enough capacity, yet we're heading down a road with mechanisms that will result in less capacity, not more, accelerated by the EPA rules, depending on the terms of those rules, which we'll see in the next couple of months. But think about it--the delivery years that are being impacted by what we're discussing today are the very years when these rules start to take effect. So there's a confluence of forces, one on the economic side and one on the environmental side that hit at exactly the same time, which is what I think you getting at with your question.

Speaker 4: Or the other alternative is more out-of-market. In PJM, which our general reference is here, you can retire without permission. You have-- is it six months notice, 90 days notice?--it's one of those two. But the reality is that the major holders of capacity are not going to do that if somebody comes back and says, "Wait a second, we have a real problem." And so we're going to see in one form or another, a trickling of RMR activities when we wouldn't have had the need for them at all, hopefully if we had better locational signals and we didn't have interference.

And the idea that you need longer-term contracts is sort of Catch-22. If you manipulate the markets so that you can't depend on the market mechanism, this control mechanism, then you're going to need longer-term markets. If the virtually impossible happened, and we could say, "Geez, these rules are both fair, equitable, make sense, and nobody's going to touch them for the 20 years or something, or the 100 years that we use to simulate how we should do the market design." Then the market mechanism itself would become the credit support. And we're just sort of stuck in the dilemma that nobody believes that now.

Question: I haven't heard good answers, actually, from you panelists, and I'm trying to get more clarity.

Moderator: Did he just insult all of us? [LAUGHTER]

Comment: Not the Moderator. You're doing fine.

Question: So seriously, on the subsidy question--subsidies, incremental costs, anything above incremental costs, Brown and Sibley says a whole set of other things. Here subsidy would be the amount over what the uncapped energy market would provide, minus what this capped market would provide. That would be the amount of cost that you're going to allocate to a capacity market. I mean, that's pretty simple. Anything else is an artificial construct. You're not talking about a quantity. You're talking about some principle. So I'm very interested in your comment on that, because to me that's the most concrete way to define this current situation for subsidy.

So second, I'm concerned about this slippery slope. What if suddenly plug-in electric fleets, Bloom boxes and Wal-Mart formed a set of bilateral contracts? Would you call that some version of out-of-market? I mean, out of market previously was when you actually had to go out of the market for emergency. The ISOs, RTOs got on the phone and said, "We need capacity now, because we've run out of everything." So you have a new version of OOM, and I'm curious about how, if we're going down that road, in other words, that any major perturbation in the market, or new innovation, would then suddenly be said to be taking away money from existing generators or existing entities.

And then third, there was a point about ramping capacity. I don't see, as was brought up earlier, that resource adequacy is anything more than reserve margin. It's not capacity. It's not specific. Speaker 2 said we need a specific capacity market. I know the West is going to need a lot of ramping capacity. How do we signal that? And isn't that the case where there's a lot of renewables coming into the system? If we don't have a market to make that work, we're really going to be out of capacity.

Speaker 4: The second and third ones are easy. I'm not sure I understood the first question. There is no intention to suggest that private bilaterals that are not non-market subsidies are a problem. If you or Wal-Mart or whoever go out with a non-discriminatory procurement and buy whatever they want and do whatever they want, it's fine. Whether it's needed or not. So I don't think anybody was trying to suggest that.

Question: Well, I don't know how you distinguish.

Speaker 4: It's easy. Well, again, I don't want to go into the details of what we've litigated, but there were a bunch of suggestions about how to distinguish. And ultimately one of the clear criteria that I think is well discussed, and we talked about earlier, is the ability to go to a third party for a non-bypassable payment. That's a real giveaway. I don't know if Wal-Mart may be able to charge its customers, but it isn't going to put it on a line item on your utility bill. And that distinction to me means that they're free to go ahead and do what they want.

On the ramping question, let's assume for a moment that it's unambiguous that we need it. There's no analytics about that. That's easy, too. We can set up the optimization, at least in the

RPM, to say you have to offer this kind of capability in megawatts per hour--or whatever, megawatts per minute--and we can have a constraint based on whatever the analytics are, and we can solve to do that. That's effectively just what we did with the proposal for DR, the way the optimization structure was set up could just as much be a constraint for ramping. I mean, in the abstract, if we knew it, we would have a shadow price for that. We would pay more for it. And somebody would measure it. And it falls right out of the structure we have now.

Question: It all looks too much in the abstract.

Speaker 4: It's not abstract. I mean, we do it now. It was originally proposed that way. The market was actually originally proposed with quick start and load following. Were those the two other?

Question: Ramping product.

Speaker 4: So if you want it, I mean, if you really need it, and you want it, we can buy it like that.

Question: Speaker 2, you praised first of all the PJM market for promoting demand response resources, and also you mentioned that in the absence of a capacity market, the policy-makers can establish what is to be paid for the demand resources, especially if it's a direct load control type program. I was wondering if you have any idea of how policy-makers can establish that price or that incentive that we pay to the demand-side resources absent the capacity market.

Speaker 2: Sure, I think an RFP to provide demand response at some level--it's hard to determine, as we saw in the New Jersey case, what the appropriate level is. But as far as the experience in every part of the United States today, the level is certainly more than we got in terms of the optimal level. So an RFP process to bring in entities that would then arrange payments with their customers and provide demand response services would be a good way to procure that outside of a capacity market. So you're going to find out what the market wants to provide this particular kind of resource that has certain benefits that are not adequately captured in the energy market, or in the current capacity market. And that would be an efficient way of procuring that. I think that would be a great idea.

Question: If I can ask, then, so it is not really an administratively-determined price by the regulator or some policy maker. There is some other market mechanism in effect.

Speaker 2: You could have something like a feed in tariff, but I think that probably would yield a higher price than doing it through an RFP process.

Question: I just will make a couple of comments to try to tie together some of the themes, because we were sort of bouncing around between the eastern capacity markets design questions, and then some comments from the canaries in the coal mine, California and Texas. And I think that unless the capacity question--how to create functioning capacity markets, as we go into this higher RPS future, is resolved, certainly in California, the wholesale markets will be dying with a little whimper over the next three to five years, just because of the suppression in energy prices, and the failure to be able to pay for those retrofits that Speaker 1 described through market revenues. So everything will retreat back into IRP-type processes where administrative decisions will be made to allow for payments for particular types of retrofits, maybe additional peakers, for example.

So it's very clear that in California, at least, the whole wholesale market design construct will sort of collapse over the next few years unless it can be reinforced with additional tweaks to the energy and ancillary service markets and with a capacity type of construct that possibly also has attribute features to it. So I think that California is a type of canary in the coal mine for this. Texas possibly is as well. And it will be very hard to move forward in either place on capacity design without some resolution on the East Coast of how the capacity markets are functioning. So I just thought that might be a nice end to the morning conversation.

Speaker 2: I appreciate that. I think that's exactly right. I think that states are being given the opportunity and have the opportunity to be the canary in the coal mine, and it's not a very attractive prospect. I think that they're seeing, as other panelists have noted, 16 to one returns in terms of the benefit of their actions for rate payers, and then they're being warned by economists, frankly, who are making a nice living working for generating companies, that there are long-term threats to their ratepayers associated with that. But those threats are pretty theoretical and potential in nature. I think that we all know that these markets are going to go through a lot more evolution in the future, whatever we decide today. So these are pretty smart folks, actually, and I work with a lot of ratepayer advocates, including in New Jersey, and they know that they can provide benefits today, and that the costs are quite speculative.

Session Two.

Easier Said Than Done: The Continuing Saga of Moving from Principle to Practice in Crafting Transmission Infrastructure Investment Rules

The recent spate of editorials in the Wall Street Journal, unusual for the arcane subject of transmission regulation, exploits the tension in crafting transmission infrastructure investment rules. The principle of beneficiary pays endorsed by FERC can be difficult to implement in practice. The editorial challenge questions the follow through with practice that is not equivalent to socialization of the costs of transmission investment. A continuing missing piece is agreement on the contents of a white paper that lays out what can and cannot be done in identifying beneficiaries and assigning costs in meaningful ways that do not reduce to socialization. How does the practice of transmission cost allocation approach the ideal? What is the ideal cost allocation method? If the perfect is the enemy of the good, what imperfect cost allocation would be good enough? How can the principles be converted into practice to raise the level of discussion? Recent sessions at the HEPG have discussed but not disposed of these issues. In the interim, a great deal of new material and information has been produced. How can we use the new information to guide the drafting of the missing white paper?

Moderator.

This is an interesting panel, "Easier Said Than Done: The Continuing Saga of Moving from Principle to Practice." That's what's government's about. And crafting transmission infrastructure is primarily about cost allocation. One of the most contentious subjects now in the financing of transmission is cost allocation for the new interstate lines--deciding how much customers are going to pay, and how they're going to pay, and which customers are going to pay is obviously something important, certainly to commissioners and I think others as well.

So it's a hotly debated policy issue. Congress has obviously been engaged in this for a couple of years now, and advocates for enhancement of the transmission grid think it's necessary, in part to exploit the renewable energy that's out in the middle of remote areas. And then there are other people who think there are less costly alternatives than to have these intrusive lines to meet our energy needs.

There have been recent developments in our energy policy at the national level that have caused cost allocation come to the fore. In 2005, we had the Energy Policy Act, and that obviously was Congress's response to a perceived shortfall of transmission investment for reliability and economic purposes. And so now FERC has a new authority and direction, really, from Congress, to offer incentives for transmission projects. Since that time, transmission investment and construction have increased.

Another development, obviously, is climate change, and there is concern in many places of the country about that. And obviously related to this is the increased interest in renewables and all the states that have renewable portfolio standards or something like them. And as we know, many of the best solar and wind are in remote parts of the country, so you would need the transmission lines to bring that to the load centers, and obviously they're costly, and they go across state borders. So you have a combination of increased transmission construction, interest by many in building new and expensive and long transmission lines, and the lack of a standardized approach for allocating the transmission cost.

So cost allocation is obviously something that stops a lot of projects or causes a lot of concern. As the write-up for this panel said, the *Wall Street Journal* has had a spate of editorials on this topic (and I think you have some brief summaries in front of you). The November 8th editorial was entitled, "The Great Transmission Heist," and the December 30th editorial was entitled, "The Midwest Wind Surtax." And they basically beat up on FERC and their NOPR from June of last year. Here's a quote from the first editorial: "the longstanding user-pays policy would be replaced with a policy of everyone pays under FERC's plan." They called it "socializing" the cost to connect remote wind and solar project, and they said FERC basically favors, "Big Wind and Big Solar." And there would be loser states. The second editorial said, "In fact, this is the first step in a FERC scheme to socialize transmission costs nationwide," and it basically said that the NOPR departs from the beneficiary-pays principle.

Well, FERC commissioners finally got really annoyed, and they had a January 10th letter to the editor that all five commissioners signed. It was short, but I think it was well stated. It refuted the editorials and pointed out that FERC didn't develop this proposal, that it came from stakeholders, and that the NOPR gave flexibility for cost allocation and that kind of thing.

So it was a hot topic, and the *Wall Street Journal* covered it. We have a great panel. They know the business, and I accepted the invitation to come, because I wanted to hear what you had to say.

Speaker 1.

I think it's interesting that the *Wall Street Journal* editorial page has now become a modern blog on the subject of cost allocation. I've taken the liberty of taking excerpts on the first couple of slides here, and I'm not going to read all of this to you, but certainly you can get a feel for the great divide on cost allocation that we're seeing, and I think these excerpts offer empirical evidence that this subject is one that people are very passionate about, and it's one that surly demonstrates that there are no easy answers in this space. (I have to say I think my favorite title here is "The Great Transmission Heist." Kudos to the person who gave some thought to that one.)

One of the things that I think a lot of folks also have been made aware of is the Corker Bill and what that might mean. And when you look at how that is characterized, I think it's interesting, so I'm just going to read how it's characterized in the background of the bill. It's to "protect consumers from footing the bill for energy projects that serve no benefit for their state or region." Sounds great. Where do I sign? But this statement is really a major oversimplification of a very, very complicated issue. And whenever there's such an oversimplification, it's certainly very dangerous as to where that kind of legislation can go.

Arguments to date on the subject of cost allocation have been divorced from the question of how do you decide what to build? And fundamentally, I think those two things are linked together. And if you take one away from the other, it really starts to fall apart. And I'm going to give a few examples of that.

In terms of the bill itself, I'm just going to read an excerpt from the bill, and it basically says that "no rate shall be considered just and reasonable unless it is based on an allocation of cost for new transmission that is reasonably proportionate to measurable, economic or reliability benefits." In thinking about the ramifications of this bill, we started to think about each of the words, for example, "new transmission." What's "new transmission?" If I change the size of an autotransformer, and I increase its capacity, and that's going to change the flows, does that mean that we're going to need to change the cost allocation methodology that's in place?

Fundamentally, I believe that when properly balanced, planning and cost allocation can work in a complementary manner and provide a rational and predictable review process for a region. Is it going to be perfect? Absolutely not. But can it be rational, and can it be predictable? Yes. And I think that's really the cornerstone of what we need to be doing here.

I'm going to talk a little bit about the PJM debate, which I think is one that's set for the history books, and which highlights the interplay between decision-making over what gets built and decisions with respect to how things get paid for. On its face, the concept seems fairly simple in terms of cost allocation. New reliability projects are going to be regionally supported at 500 KV and above. The complication arises when you start to peel back the onion, and you start to look at the ramifications. And you have to also consider some of the history here. The history here is one where you basically had strong systems and weak systems merging together in one RTO. You basically have old systems, new systems, all coming together. For the most part, you've got a fairly strong system in the West, a lot of very high voltages, a very strong 765 system and a very strong 500 KV system that PJM and all of its companies have really benefited from for a very long time.

But there's a very strict reliability standard in terms of determining what transmission gets built in that region. And fundamentally, it's only if there is a threat of wide-scale voltage collapse or thermal limitations that any transmission actually gets built in PJM. And that is a very high threshold. It's a higher threshold than we're seeing in a lot of the other RTOs, than certainly has been in place in ISO New England, SPP, ERCOT and now MISO with the revision of their transmission planning process. The PJM planning process was challenged, or the cost allocation methodology certainly was challenged, in the Seventh Circuit decision and the remand to FERC, where FERC needed to create an evidentiary record in support of the cost allocation methodology that they had adopted.

What you see here in the diagram is some of the examples that show how when you look at it from a benefit standpoint through a DFAX calculation, you see some pretty major discrepancies compared to looking at in essence what your total cost is for some of these new projects. And what this highlights is that when you look at systems on a line by line basis, and not from a systems standpoint, or as a group of projects that are collectively benefiting the system, you have some fundamental problems.

One of the situations that you face is the problem of perception versus reality. The primary argument against broad-based cost support has been this fear of overbuilding, this fear that we would promote free ridership and that generation would be insensitive to location. Our experience in RTOs, and our experience particularly with SPP and ERCOT, has certainly been different from this, and one of the things that we have seen is that when you have cost allocation and planning done in concert, in fact you're bringing multiple stakeholders together and questioning the need for projects during the RTO planning process. They know how they're going to be paying for the project. They have that predictability, and what folks are doing, once they understand how these projects are being supported, they then look at the planning process, look at the results of that planning process, and question it intelligently.

We're seeing that there's a higher scrutiny from stakeholders with respect to the costs of approved projects in those jurisdictions, and again, I think it just really fundamentally gets down to the fact that it's very predictable, as compared to an approach which could be advocated by adoption of the Corker language, which in my view really leaves the question as to who pays for any given project very much up in the air. And quite frankly, if applied on a line-by-line basis, it gets very confusing as to who's going to be paying for the line, and what happens when you have one line that has a certain set of beneficiaries that are determined to support that line, and then three years later you build another line, which is changing the beneficiaries of the first line.

One of the things that I'd just like to mention briefly is the challenges associated with the quantification of benefits. Lawrence Berkeley Labs, and this dates back to a 2009 study, basically took a look at some of the cost simulation models that are currently in place, and really questioned how the benefits are actually being calculated and made a series of recommendations. To date, no RTOs have adopted those recommendations. So in fact, what we have when we're looking at quantifying the benefits is a situation where we're underestimating or undervaluing the benefits associated with these transmission lines.

In terms of solutions--and I know that that's something that's going to be part of a broader discussion--I just want to throw out a couple of concepts for folks to think about. One of the things I think is fundamental with respect to cost allocation is that the states need to stop counting. The states and the utilities need to stop counting who's up and who's down at any given point in time. And what you saw on the slide that I just had on PJM is in fact a +counting. Who's paying for what? Who's benefiting from the line?

I think ISO New England, actually did a very nice job in terms of how it dealt with cost allocation, where it took the existing assets, it rolled them in over a ten-year period, and then new assets, for the most part, are regionalized, all through a very detailed transmission planning process. That kind of predictability is the kind of thing that really needs to be promoted. I'm going to leave the other suggestions just up there. You can take a look at it, and certainly we can have more discussion later. Thank you.

Speaker 2.

What you are going to hear today, even though the objective is to focus on the NOPR, is an engineering perspective and functionality perspective related to the systems planning process for the Atlantic Wind Connection project. I have about eight topics, so I'll just proceed through them.

As background, here is a composite picture of the intensity of electricity use in the United States. And if you really look at it closely, you will find that much of the load is really hugging the coast. And when I say the coast, it's not just the Atlantic and the Pacific or the Gulf. I'd include also the Great Lakes. So the first thing that occurs to you is that that's where the load is, and that's where the growth is going to continue. In fact, if you go further inland about 100 miles, basically you account for more than 70-80% of the US load.

The second thing is, you look at this next map (and it's outdated, by the way. There's a newer one that NREL has issued.) Look at the intensity of the wind along the coast. And it provides a great resource. One of the best locations is right here along the Mid-Atlantic states where there happens to be actually not only quite a bit of load, but very valuable load as well. And building inland transmission in that area is a very painful process. So it's a confluence of a number of things. There's also congestion. And that congestion is chronic. It's still there. It will continue to be there even after the three major projects have been approved, the MAP project, the PATH, and the Susquehanna-Roseland. You cannot actually add more inland. Most of the heavy weight is being carried out by what we call the I95 backbone.

So the Atlantic Wind Connection project basically is to provide a relief for that. This is a very simplified picture of what the project is, about 350 miles-plus long. It consists of two circuits. The circuits are interconnected with the system at several points, but they do not directly interact with each other, for reliability purposes. It will be set back somewhere between ten to 25 miles away from the shore. And basically it's a spine, a backbone. Think of it as a horseshoe, but in the middle, there are laterals that extent from it to bring the wind power connected on the sea side to the land. There are two sets of converters. Converters are connected on the backbone offshore. They will start with 500 megawatts, and we may actually go immediately to 1,000 megawatts. Technology is moving very fast to the larger platform. On the land side there will be equal capacity of onshore converters, and that will change electricity back from DC to AC and inject it into the grid.

The project is sponsored by three large companies at this point. Google and Good Energies, which is a European firm fund that focus on renewables. There are a bunch of European families behind it. There is also

Marubeni, which is part of a Japanese trading conglomerate. The project development is led by Trans Elect, and you can see here that DC Interconnect, which I am part of, specializes in the integration of DC into AC in a systematic way. And our attorneys are Dewey & LeBoeuf.

This is where we start getting into how this project relates to the NOPR. So I will switch to what I call a functional description of this machine, and it is truly a machine. When we presented this to one of the largest companies that does transmission offshore, they said, it will work, but this has never been done before. The technology to do it exists, but it's a quite interesting concept. And the Europeans started thinking about it and doing this thing. There's efforts now in the UK, off Scotland, to create a similar concept, and one in the North Sea.

Now, these multi-terminals consist of a spine. That spine acts basically as a network element. And if you want to think about where does that ring a bell, think of the Tehachapi Decision. The Tehachapi Decision looks at that project as made of two parts, the network part, which, when it gets connected from the north, becomes part of the grid. It's not a radial anymore. And a bunch of radials from the wind generators that integrate into it. So essentially, that's how we look at it.

Now, if we look at the functions the backbone will provide, it will enhance the reliability of the system—of the regional grid, we expect beyond even the PJM. It will relieve the transmission congestion, and it will improve the efficiency of the market operation. The integrated system of generation ties provides three additional services. It will access remote offshore generation, which you can't do with AC. You have to have DC to do that. You can't go that far with AC. That will facilitate large scale offshore wind implementation. That's a very key thing to this technology. Today, [the typical size of turbines] is about 3.6 megawatts, which is somewhere about 300-400 feet. The industry is moving fast to five, seven, and ten megawatts. Economy of scale is the key to it. It's a capital-intensive industry. Now, these [turbines] are very large. They're going to create opposition from people on the coast who say, this spoils my view of the horizon. With this project, you can set it back. That's a degree of freedom. And the regional wind integration lowers those costs.

This is a study [of project costs and benefits] that we did with the help of our friends at Brattle and Ventex. Think of it as a first round of estimation. We will follow it with final numbers. And you can see that the project is very expensive. But when I say $30 billion in costs, most of it is really the wind generation, which we are not investors in it. We're investors in the transmission. But these are twins. They go together.

The benefits are already quite close to paying for this project. The barriers are the perception of the high cost of wind and transmission, the presumption of cost socialization (which is really the Achilles heel here), the [need for] assurance of timely arrival of the wind generators, the inadequacy of the PJM RTEP process for accounting for a public policy projects (and this is not my statement--it's a statement of PJM itself, which said their process is not geared for that), and then potential environmental issues.

Now, the NOPR will deal with four out of these five barriers. And that's why we are paying very special attention to it. The directly relevant aspects of the NOPR are two: reforming the regional transmission process and allocating costs to beneficiaries. And recall the maps that I showed earlier. If we can show that this can work, you open the door for further development of off shore transmission many, many places.

Now, I don't want to go into the details. You have a copy of that. But basically they reflect what I just said, and I want to leave you with the thought that we would not be seeking cost socialization. That's very, very important to remember, because we don't think in this political environment we can get away with that. And the key to it is to identify the benefits, identify the sources and the sinks of the benefits, allocate them, and then allocate the costs in proportion to the distribution of the benefits.

Now, I know there are a lot of devils in those details that are awaiting us, but the purpose of this meeting is to develop a white paper, and I think that we can do that and articulate it in a manner that will actually cover many projects. Now, the relevant precedents are the NOPR, the CAISO order, the Midwest order and the Tehachapi Decision. And I describe those as how I think it can be done. I want to tell you here, there's no cost socialization, but in fact, we will do two things for those who speak the tongue of the Wall Street guys. We will say, "we will eliminate the free rider problem, or at least we will minimize it." And the second thing, we'll even de-socialize pre-existing socialized costs.

And that brings us to one of the themes that we talked about this morning. This slide is a three bus model of how at certain times, the bid prices can, with the interaction with what's called the shift factors or the power load distribution factors, can play havoc with you, and this is a double saddle thing that will provide either very high spiking prices or their mirror image, very negative prices. And that's what prompted the RTOs to impose price caps and price floors. And any time your result is something like that, you have inefficiency, and you have a degree of socialization, because you couldn't deal with that problem.

With our project, because of the controllability of the power flow injections and withdrawals, we can minimize the incidence of these spikes or sink holes of prices (and this is something we're working on within the next few months. We will release the results, we hope). I don't know whether we can actually eliminate them or not with only 6,600 megawatts, but I can tell you, it will have an effect. We're hoping it will have an effect to the extent that the PJM will say, "Well, we need to revise our policy toward price controls. We may have something such that technology itself can actually intervene, and we don't have to rely on these market rules." And we expect a favorable Section 219 ruling from the FERC in about a month or so. Then we'll go into the RTEP planning process. And the Bureau of Ocean Energy Management, we're applying there pretty soon. And then we conclude it, hopefully, with a Section 205 filing.

Speaker 3.

If transmission planning and cost allocation aren't linked, they need to be linked. So I will talk today about both cost allocation and some of the ways that we do transmission planning, and what actually are the drivers, because at the end of the day, I think it becomes clear, you at least need to look at those items together.

Obviously, if you want to know where you're going, you've got to start with where you are. So at this point, here is the cost allocation as it is today. We have the legacy transmission system that's sometimes overlooked. It is there. We still pay for it today. It was allocated historically to transmission zones--I guess a license plate rate mechanism would be the best way to describe it. And it's load ratio share allocation within those zones.

And we have the new transmission that comes along. There are two broad types. One is driven by generation interconnection, which uses direct assignment of costs to the project developer. Generally that has been viewed as more of a success story, or less controversial. But in some cases it has created some issues, which I'll talk about later, because when you couple it with an overemphasis on equity, sometimes that can create some issues. So we'll talk about that a little bit later in my presentation.

Then we go to the reliability and market efficiency upgrades. These are the upgrades that are driven by PJM planning criteria as it exists today, and I'll define that a little bit later. There are two flavors. One flavor is greater than or equal to 500 Kv. That has its own cost allocation method. It's called socialization of load ratio share. For loads below the 500kV level, there's a beneficiary pays concept, generally driven by load being the beneficiary (a somewhat narrow view of beneficiary), and it's driven by DFAX. So that's essentially where we are today.

Next we talk about the regional planning process itself. We have effectively various tiers of planning. Some of these are actually in place. Some are being contemplated.

If you look at the reliability tier of planning, you have a baseline analysis that says where the system is expected to be over a period of time. And you look at the load growth impacts, and then you look out, obviously, into the future. You have very specific reliability tests that are done, whether they be voltage or thermal type analysis that says you either trigger or not. And if it's 99.9% loaded, it doesn't trigger, and if it's 100% loaded, it does. So it is called a bright line, and you build for a strict violation, and that's the way it is.

There is a concept of scenario planning being discussed. And I'll have that on my next slide, so I'll skip that for now.

Then you have basically economics as another tier of planning analysis. There are two flavors. One is being considered. One is already there. Basically you look at economic indicators. In other words, what is going on on the system currently? What are you seeing based on transfers? And obviously the reliability criteria tests do play into that. The concept is, again, a criterion that looks at not only the reliability upgrade, but also some of the economics and almost does a two-pronged assessment. That, in my opinion, is fertile ground for consideration, and there certainly is consideration of that.

Then you have market efficiency analysis, which is already in place as a means of evaluating proposed transmission. There's a set of rules under which it gets done. It looks out over time. And it effectively is looking at the economic benefit [of a proposed project]. Now, the way that is measured is obviously very critical. I think the test was carefully crafted to make sure nothing could possibly trigger it, at least on a high voltage level. There are some lines where the amount of transmission congestion that is actually resolved with those lines is close to a billion dollars a year. And those lines fail the market efficiency test because of the way you measure market efficiency. So it's actually astounding that you can create a trigger like that that would be a trigger to effectively do nothing.

If we go into the concept of a cost/benefit analysis, and you look at the potential ways you could approach scenario planning, one of the things we look at is, if you have a series of scenarios that you look at, whether it be high load growth, low load growth, high emissions cost, low emissions cost, whatever, and if you have a situation where you have a fairly tight envelope, where basically any way you look at it, there's benefit, then that's a very easy decision, and you can actually write some rules around that pretty quickly.

Then, of course, you have another concept of scenario planning, which says you essentially do the same thing, but your benefit envelope is quite wide, and in fact, negative in some cases. And then you say, "Well, what is normally the case when you do scenario planning on these large-scale projects?" The answer is, you probably get something in between the two. You don't really get a great envelope, and at times [the results are] somewhat counterintuitive.

What that says, then, is that if you would move to a concept of looking at scenario planning, again you need to have some fairly good ways to make decisions about how, in fact, you're going to interpret those results. So again, I'm trying to make sure we understand the nuts and bolts planning side of it as we talk across allocation.

So we have economics, and we have reliability. Those are our two main drivers in PJM. Now, if we go to the next slide, to the FERC NOPR, we can see some language related to the question of whether we should be planning for public policy requirements. The language says, essentially, that you can look at public policy needs, whether they be defined by states or by the federal government. I guess if I look at my next slide, I say, "What is a 'public policy criterion?'" Is it offshore wind? Is it onshore wind? It is solar distributed all over the place? Whatever. I mean, we have very clear drivers today under the reliability criteria and the market efficiency criteria. We know what those are. You can engineer them. You can plan them. You can calculate them, even though we may disagree on the various tests. I think you can put something to that and make decisions. If it's a public policy criterion, how would I, as an engineer, approach developing scenarios around public policy criteria? So I think that one is going to require more discussion.

I think the fear that we have, at least, is that if it goes this way, at least in the PJM divide, obviously you'd have one group of states or constituencies who would want their public policy criterion to be offshore wind. You'd have another set who wants their public policy criterion to be onshore wind in the Midwest. And the one side wouldn't want to pay for the other side's mistakes or perception. Again, it looks like it's building to a point where what would happen if you went that road is nothing. So I think if we take that theme, I think we'll move into some of the next discussion on transmission planning itself.

So let me step back and say, OK, what is planning in this sense? Again, the technical assessment of needed upgrades--that's what planning is in its simplest form. You say, "OK, how do you do the technical assessment?" Again, we have the three criteria that we've just discussed. One is the reliability criterion. Within the PJM system, the reliability criterion is very targeted, very bright line oriented. For the 500 Kv system, though, the cost allocation is socialized. How do you rationalize a very strict bright line test that says, this particular problem is being solved in this particular area? But then, oh, by the way, the cost of solving that is sent to everyone. And it is a 500 Kv, so it is broad. But the Catch-22 there is, if the reliability criterion is going to be so strict, how do you rationalize the cost allocation? I think the point is that you may want to look at the two together as a way to move forward.

The same thing with market efficiency analysis. If the market efficiency analysis is going to be so broad--meaning it's not going to look at just congestion, it's going to look at a variety of other things across the broad region--then maybe you can make statements about how cost allocation would actually get done through that.

And of course, when it comes to public policy criteria, I don't see anything but socialization there. I'm sorry. I don't know how you do a broad public policy and then assign that to specific beneficiaries, because the folks who want offshore wind, if you tell them they would benefit from the onshore wind, and they should be happy when they pay for it, I don't think it's going to happen. (I retire in 2027, I keep reminding myself and many others of that.) [LAUGHTER]

Moderator: You're already counting.

Speaker 3: I am counting. I have been counting. I don't think we're going to get agreement by the time I'm ready to hang it up.

So anyway, again, if we look at the process of our planning, I think we've already identified within PJM, and this took a while, but that the bright line test may need to evolve. We may need to evolve into more of a probabilistic analysis, because again, you're planning for 15 year horizons, and to make an educated guess on when you're going to have a problem, much less a problem for which you need to allocate costs to people, and they should all like it, to say that you're going to do that on one set of assumptions is a very difficult hurdle. And I'm not even talking about siting. I'm just talking about the criteria itself and paying for it.

So if we go to the next slide, you look at FERC's rule making and pull a couple of things out of it. Obviously regional planning is required, of course. There's a concept of the cost allocation being commensurate with estimated benefits. Again, that makes some sense. One big deal, though, is the equal treatment for non-incumbents. That's a big deal. That is, how are you going to have complete equity and still get things done in an efficient manner? That, I think, is a conundrum that we don't talk about very often. And of course, interregional planning is vital. We have to solve that problem. And of course, this whole public policy I've already talked about, so I'm not going to go back into that.

If you can forgive me, I'm going to skip my EIPC slide. I may come back to it. But I really wanted to get to the punch line on this if I may.

One of the things we've seen is, again, that the FERC direction seems to be driven by, or at least to be very conscious of, equity concerns. And if I could pause for a minute, it's not only on the transmission planning side, but it's also on the generation interconnection side. So to tell a story to illustrate the problem, say four generators want to intersect in the same spot. PJM analyzed the system and said, "OK, if each of you want to interconnect, that means we've got to put four generators in, where probably only one is actually going to go in." So PJM would assign costs out to those four to split a fairly large transmission bill, because obviously it's going to cost more to interconnect all four. So PJM assesses that cost, and sends back to each of those generators, the message, "Hey, here is your piece of the cost allocation because of the direct assignment." They all look at it and say, "It's too much." Their incentive as a group is to sit there, invest nothing, and do nothing except keep themselves on the books until the rest of them fall out by attrition, and then finally, four years later, something might get built.

So the incentives right now, through a combination of the way cost allocation is done and the way the equity question was answered, is that they sit there and do nothing until the last one is standing, so to speak, and then finally

…The point is that part of why people are hesitant to go ahead and jump in and build is really driven fundamentally back to some of these issues related to equity and cost allocation. So we've got to get that kind of stuff solved if you're ever going to get transmission built, let alone generation. So some of these issues are coming up on the transmission side, too.

The other thing they require is ongoing analysis updates and bright line triggers. Well, I've got to tell you, if you analyze a transmission system every year, and you have a bright line, guess what's going to happen. The answer's going to change every year. Is anything going to get built if the answer changes every year? It doesn't matter how you allocate the costs. Again, the point is, if you can get cost allocation right, and you get people comfortable with the cost allocation, maybe you can loosen up some of the triggers and be willing to go ahead and take a risk that perhaps you might put something in a few years too early.

So those types of things are on our mind as we approach the next year. The interaction of the capacity markets in transmission planning--this is not a news flash. It is not stable. (Commissioner Fox could have told me that three years ago). A lot of it has to do with these equity issues we've been discussing, where you have to sit there and wait until everybody's satisfied as to whether they're going to actually invest or not, before you actually pull the trigger. I think having an incentive mechanism to say that the first generator to actually get the permits and put their money up gets to build for the lowest interconnection cost, I don't care when they came in, might be a better way to allocate cost.

Again, the concept here is, I think we've built all of this up between the transmission planning criteria and the cost allocation. We have a big incentive to do nothing. And I think that can be fixed, but it can't be fixed in isolation. You can't do cost allocation without doing something with the criteria on planning. This is a long way to go about saying you've got a fair amount of alternatives here. I think socialization probably makes sense in some cases for broad policy, perhaps, although I've got to tell you, you're going to get arguments there. My own opinion is that some type of flow basis or monetary measure seems to make the most sense. And certainly loads are not the only people who benefit. Thank you.

Moderator: Thanks, Andy. And I forgot to ask, any clarifying questions for Speaker 2?

Question: I do have a clarifying question, but it's something that I'd also like to discuss later on. On slide nine there was a cost and benefits list. And I think it would be useful if everybody would eventually opine about whether or not they think something is actually a benefit. So the first row has costs of 30 billion, and a small question is, is that after federal subsidies or not?
Speaker 2: It does not include federal subsidies.

Question: So it's pre-subsidies, right?

Speaker 2: Yes, pre-subsidies.

Question: Then the next one, $12 billion production cost savings, that seems unobjectionable to me as a benefit. $17 billion LMP reduction would appear to me entire a transfer payment, in other words, a pecuniary benefit. And I personally wouldn't include that as a benefit, and I wonder what everybody else's opinion would be. I'm happy to include the $5.2 billion CO2 decrease. I think that's a benefit, although I have no idea how it was valued. Job creation strikes me as implausible as a benefit. So in my addition, I get $17-18 billion of benefits and $30 billion of costs, which would seem to me to be a fairly clear statement that we shouldn't build this project. And I'd like to know how you'd respond to that. Maybe that's not a clarifying question.

Moderator: It's not really a clarifying question, but we'll let that one slip by.

Speaker 2: I'll be very brief. One thing I didn't mention here, is that there are reliability benefits that we haven't estimated at all. And some people think they are very difficult to estimate, but I've done that work before. I don't think it's difficult. It can be done. A second thing is economy of scale we haven't even touched with respect to the wind generations themselves. So there are a number of things about that that I think we can take care of.

Question: For Speaker 2, my question is, are you proposing to allocate the cost of the wind turbines and the transmission lines together as one project? And is that a difference from the way that wind projects have been funded in the past in the region?

Speaker 2: You touched here on the most critical of all questions, because the wind turbines themselves, they are expensive. And we constitute only about 25% or 30% of the total cost. Yet the project operates together, and they provide benefits if we establish that the wind generators, in combination with our project, can make this market operate better and actually reduce the cost, make the LMP more flat terrain than the gradient that we see today consistent from north to south. Somebody has to pay for that.

Question: We can debate this more later, but it just sounded like that answer just said the beneficiaries are the wind generators, they should pay and put the cost of the transmission and the generation to those who who buy, and that will take care of everything. Is that what I just heard? That's what I thought I just heard.

I just wanted to know if I heard that you're talking about bundling the generation and the transmission, as a clarification. We'll debate what that means later.

Speaker 2: I'm not talking about bundling them. And I'm not talking about giving anybody a free ride. Our project, the AWC is transmission only, and it will be utility, and it will be treated like a utility. What we're saying is, the cost of the wind itself has to be leveraged by the benefits the wind provides. And the mechanism for doing that has not been determined yet. We're working on that one.

Question: Yes, and it's on the wind turbines. How far from the shore are they? I'm having trouble visualizing this.

Comment: 15-20 miles.

Question: 15-20 miles. And it says they're built on the continental shelf.

Comment: Outer continental shelf, yes, straight out. You don't have one over here.

Question: No, I know. That's why I'm having trouble. But OK, thank you.

Speaker 4.

I'll try to do this quickly, even though the topic is the "continuing saga." So I figured I sort of needed to put more slides together than I could possibly cover, because otherwise this wouldn't be a saga. But before we go into this, it's always instructive to figure out how much transmission has actually been built, because everybody talks about how much we've built or how little we've been building, and we've actually been building a lot, despite the challenges that we are facing, and we about tripled the annual investment since the early '90s.

If we're going to look forward, these two lines on this slide shows what we think the next five years look like. There's some uncertainty, but we're talking about building between $12-18 billion worth of transmission a year over the next five years, and we're not even now talking about a lot of the public policy benefits, the big wind integration or anything like that.

So how much are we talking nationwide? Well, we're talking about $60-80 billion over the next five years. We have about $80 billion of projects in our database that, if they're going to get realized, are probably going to be realized after the five years.

And we've calculated a few numbers of what it would take to integrate the renewables needed to satisfied state renewable standards around the country. If we just take the state standards right now, it would take between $40-70 billion to just integrate that much wind and solar, not even assuming that all of the RPS standards are satisfied by wind and solar. If there ever is a federal RPS standard at 20%, we'd be in the $80-130 billion range.

So there's a fair amount of transmission pent up, and then we ask ourselves, well, how does that get built? How do costs get allocated? Let me just remind you quickly, what already works pretty well is cost recovery for traditional single-utility, single-state projects. It also works reasonably well when we talk about cost allocation at the RTO level for reliability projects. And there are some notable exceptions, like California and Texas, where most of that has been solved, but still mostly unresolved are the big multistate, multipurpose transmission projects that are not built and recovered by single utilities and that don't fit neatly into the reliability and economic efficiency tariffs that some of the RTOs have, or in the non-Cal ISO west, where you just don't have good processes for multi-utility cost sharing, even though that works better than one would anticipate.

So for these types of projects, how does cost allocation become a barrier? Well, traditional transmission planning works pretty linearly. You do some planning, determine the benefits and the costs. You go through a state permitting process. The approved projects receive cost recovery, and then you build them and put them in rate base. If you have multistate, multi-utility projects, this all gets sort of intermingled, because all of a sudden, the benefit to the state is evaluated against the cost to the state. So you can't do planning first and cost allocation later, because as soon as you go through state permitting, the state will say, "Well, OK, where's the need? Where's the cost? What are the benefits?" And so you almost have to simultaneously resolve planning, cost allocation, and state permitting, and that's just very difficult. And in any beneficiary pays framework, you create additional problems, because if you understate the benefits you receive, you reduce your cost allocation, so everybody has an incentive to understate the benefits, and by the time everybody's done understating the benefits, the total benefits don't add up to justify the project in the first place.

Which gets us to the whole issue of, what are the benefits and how much that is measurable? There's a big fight over the term "measurable." You know, the *Wall Street Journal* and the Corker bills in the old and new form, they're all over this term "measurable." Cal ISO, SBP, MISO and ERCOT have all in place postage stamp tariffs for policy-driven regional projects at certain voltage levels based on the showing or belief that the benefits are sufficiently broadly distributed in that region to justify a postage stamp treatment. And I really like to use the term postage stamp, because I think socialization is not a constructive term. Plus, I do think that there are probably better jokes over postage stamp and going postal than about socialization. [LAUGHTER] But I'm actually quite serious. At one of the conferences I said teasingly, gosh, how could Texas agree to socializing transmission costs? And the answer was, "Well, first of all, we don't call it socialization. We call it uplifting." [LAUGHTER] So it's all in the perspective. And you just have to be creative with terminology before you actually go into this. And I think if you don't want transmission to get built, please use the term "socialization," because that will actually work.

The FERC NOPR is interesting, because even though the *Wall Street Journal* and other blame FERC for pushing socialization, the NOPR itself actually is really quite clear that cost allocation should be based on cost causation or beneficiary pays principles, but that these costs allocated should at least be roughly commensurate with estimated benefits. That's a big qualifier. If you look at the Corker Bill, for example, that says, "…no rate…shall be considered just and reasonable unless… based on an allocation of costs…reasonably proportionate to measurable economic or reliability benefits to one or more persons that pays that rate." If you take that literally, you couldn't build a distribution substation, because how do you prove that what you spend on distribution within a single utility is reasonably proportionate to measurable economic benefits to one or more persons? It's just a recipe for disaster, and I do think that a lot of the politics behind this is really between people who don't like transmission to get built and between entities who are not keen in building transmission for renewables, and those might all be justifiable objectives, but I think it also gets in the way of a lot of transmission that is needed and that is beneficial almost by any standards.

Well, on benefits, the trouble with transmission benefits, why it's so difficult to have this measureable standard is that they're very broad in scope. They go from increasing reliability, to reducing congestion, to increased competition, to risk mitigation, to reducing losses, to renewables integration. They are widespread geographically, particularly at the 345 and up voltage levels. You have multiple states and multiple transmission service territories. You have multiple regions. And they're diverse in their effects on market participants. One thing that was said in answer to the question of why they came up with a postage stamp for Texas, at the end they say, "Well, we've got people in West Texas who really like wind farms to be built, because that results in jobs and lease income. You've got people in the cities who want cheap renewables. And by the time we tried to figure this out, we realized everybody gets some sort of benefit out of that, and we might just as well uplift the costs to all customers, because everybody will receive one or the other benefit over time."

But we are building something that will last for basically a lifetime, and nobody would have anticipated the kind of benefits that we're deriving today from the transmission system that was built in the '60s or '70s. Part of the problem is that a lot of transmission benefits are difficult to quantify. People call them "unquantifiable" or "intangible," but nothing is unquantifiable. It's just a question of how much effort we put into quantifying these benefits. But unless we quantify them or at least qualitatively acknowledge them, there's a good chance that we will turn down a lot of beneficial transmission projects simply because what we quantify isn't all the benefits, and so it looks like the benefits would be less than the costs.

And a big problem in doing that is that we in the industry just love models, and we're over-relying on production cost models. Back in 2003 already, I like this quote from SSGWI, which is now TEPC in the WECC, where they say, well, the real social benefit of transmission really come from enhanced reliability, reduced market power, decreased system capital costs, variable operating costs, changes in total demand and so on, but the benefits associated with reliability, capital costs, market power, and demand are not included in production cost analyses. It sounds like it's a big model that considers everything, but it's just quantifying the dispatch cost saving. That's like trying to justify building a new road based on the fuel cost savings of the cars. I mean, it's just all about variable costs, and you can never justify transmission with just the production cost run. This is a list of all the benefits that are not included in running PROMOD or GTMax or whatever these models are. These are very important benefits, and I won't go through them now. But if you then have some of the benefits quantified, you realize that some benefits you can quantify for the system as a whole, but it's very difficult to quantify how they are precisely allocated to individual regions.

So if you try to use allocated benefits in your cost/benefit analysis, you're further undermining transmission projects, because a lot of the benefits where you can calculate how they're allocated across the system are even less than the benefits that you can allocate in total. So I actually think one thing we need to do is make this a two-step process, where first you look at the system as a total and say, what makes the most sense? What's the reasonably lowest-cost combination of transmission and resources that we can consider here? And then once you figure out something that's reasonably optimal for the system as a whole, then worry about cost allocation.

Before I get to my conclusions, one piece I think is very important, and that is, we have to get from a cost allocation on a project by project basis to a cost allocation for regional plans. If you try to figure out who benefits from single projects, from single transmission lines, you can spend an inordinate amount of time and money trying to figure that out, and it's going to change by the time you build the next project. And it looks like the benefits are very unevenly distributed. But once you figure out what kind of regional plan is needed for the long term adequacy of the system, you realize that you need to build pretty much everywhere over time, maybe not exactly at the same time, and the more projects you put together in a total evaluation of the entire regional plan, the more you'll find that the benefits are fairly evenly distributed. Maine almost left the ISO New England because it didn't want to pay for all the transmission costs in Connecticut. Then they realized that they need to build transmission, too, and they are actually better off being part of the ISO and having Connecticut pay for their transmission over time. So you'll find that postage stamp allocation actually works better than many people realize.

The state committee in the Southwest Power Pool (and I find this just very smart to have the cost allocation be delegated to the state committee)studied this for about three years, megawatt mile pricing, all kinds of transmission pricing methodologies. When they realized by the time you built all the transmission that is needed, a postage stamp, or the highway-byway system is actually working out pretty well, and that's where they ended up.

We talked about the status quo. What would be takeaways, options and recommendations? Well, first of all, I think we need to realize the only way to get transmission built and costs allocated is with strong support and direct involvement by state policy makers. The RTO's transmission and market participants themselves are just unlikely to move beyond sort of the least common denominator approach without broad state level support. The problem also is that state commissions often lack the authority to consider broad public policy objectives, so you need more than just a state commission. You really need state policy-maker support for a regional solution.

I actually think the perfect solution to regional cost allocation is whatever the states can agree to. I think the economically perfect cost allocation just won't be good enough. And I think to get to a broad state support we need to aggregate and simplify. Formulaic beneficiary pays is just not going to work, even though as economists we'd love it, because we could study this forever. We could study this until Speaker 3 retires in 2027 and still not be quite at the optimum. But we need to aggregate projects, and I think we do need to consider regional and subregional postage stamp transmission tariffs as a workable second best solution, as long as the states can put their support behind that. And maybe we'll leave it at that. There are a few slides in the appendix for nighttime reading pleasure.

Question: Just on your last slide, when you refer to RTOs, etc., moving beyond a least common denominator approach, just explain what that means.

Speaker 4: Well, what I had in mind there is, if you look at the current tariff for market efficiency projects, that was sort of a tariff designed by committee, and what was approved was a least common denominator approach, something that everybody then could agree with, and it just doesn't work.

Question: Right, something that's not too objectionable to anybody.

Speaker 4: Yeah, you only rely on stuff that you can easily quantify, and you don't want to run scenarios, and by the time you're done, you have a formula that looks good on paper, and the first time you apply it to a transmission project, you realize, gosh, we can never approve anything with that.

Question: I disagree. It doesn't even look good on paper.

General Discussion.

Question: I think my question is generally aimed at Speaker 4, but let me preface it by saying, I think there probably is general agreement now that cost allocation should be done on a bundle of projects, not a project-by-project basis. And that was, in fact, the case that the Seventh Circuit had in front of them. It wasn't a single project. It was what Speaker 1 put up there in slide five.

So let me just add a few things to Speaker 1's slide five, and then ask a question. Speaker 1 put up the allocation of the cost of transmission. Since then, PJM has done some analysis of the effect of some of these lines on RPM prices. They had previously done the analysis only on the trail line, but now they've done it on some of the other big lines, and they show uniformly major, major decreases in RPM prices in the East, and in Eastern MAC and in Southwestern MAC, and increases, but not corresponding increases--it's not one for one--in the West. So add that to slide five. And then the third piece of information is, given the chance in the remand (and PJM stayed neutral in the remand) the proponents of postage stamp could not quantify any benefits to the others. It was all soft—"You know, there are these benefits." There was absolutely no even attempt at quantification. But given all those facts, after how many years of one sidedness does the postage stamp approach become unreasonable? Or maybe PJM's the oddball and needs something like subregional postage stamp or something. But I guess I'd like the answer, especially given what Speaker 3 said about how public policy projects would not end up getting socialized. And that would leave a regime where for benefits in the East, costs get spread, and for benefits in the West, costs do not get spread. So I guess I'd like comment on that.

Speaker 4: Yeah, I can certainly give you my immediate thoughts. First of all, it might well be that PJM is too large, too rich, has too much of an East/West gap, just from a policy perspective, because I cannot see Maryland and Illinois agree on transmission cost allocation ever, but maybe that's just being too pessimistic. But I also think that the projects that PJM is looking at are all projects in the East. PJM has not planned any renewables integration projects in Illinois that would allow the Illinois wind farms to be integrated and avoid overgeneration conditions.

So when I talk about a regional plan, you can't have a plan that's targeted to reliability problems in Eastern PJM and not also look forward enough to see whether something needs to get built in Western PJM. And as long as you do cost allocation on projects that are mostly there to benefit Eastern PJM, you will never get Western PJM on board with that cost allocation, unless you want the generators in Western PJM to pick up some of that tab. But we've looked at this before the NOPR came out, and we convinced ourselves that the most logical size where postage stamp allocation is workable and feasible politically is probably a five to ten state region, and not much larger. And it might well be that in PJM you'll end up with a subregional allocation of some of the public policy projects.

Speaker 3: I can make a couple of comments. Again, I think on the one hand, this concept of broad socialization of costs, and on the other hand, these very stringent bright line criteria focused on effectively one or two corridors, they just don't match. And I think that either the criteria can change, which would essentially broaden what maybe the results [of transmission needs analysis], or the cost allocation can change.

But I think if you don't put things together like that, then you continue with this conundrum, and if the criteria results in building everything in a similar area, then postage stamp is just not going to work. But changing the cost allocation approach is only one side [of the problem]. There's another side. You can also change the criteria triggers, and it may be in the best interest of a region to do that.

Speaker 1: And just to add a couple of thoughts on that, I think that you also have to look at the history and the infrastructure that came into PJM and how that's different from infrastructure or the lack of infrastructure in some of the other RTOs. When you look at MISO, SBP, ERCOT, one of the things associated with all of them is that when the RTOs in essence were formed, they were formed with very weak transmission systems, and PJM inherited the best transmission system, one could argue, in the country. I mean, I think there's also a very strong backbone system in the Southeast and the Northwest.

So when you take that into consideration, you've got a couple of different approaches. If you're taking a very narrow approach to transmission planning, I agree that the postage stamp approach isn't going to work. If you take a broad-based approach--and probably given the strong backbone of those systems, you might need to look at more of what New England did, which is somehow recognizing that folks did, in fact, spend a lot of money on that existing transmission system and compensating them in some fashion.

Question: Thank you. So one thing that I've always found interesting about this, and Speaker 3 alluded to it, and there's irony in his talk, as well, is the idea that "beneficiaries" always seems to mean load, even though we know there are plenty of benefits to generation, and to the regions where generation is built, to building the transmission system to support them. Of course, there is one exception to that, which is that a lot of folks seem to think that when it comes to wind, which by its very definition is a socialized benefit, that the wind generator is the beneficiary that should be paying for transmission. And I wonder if you think that this paradigm of load being the beneficiary that pays, whether that's still open for discussion or set in stone, or how that came to be.

Moderator: I'm interested in this, because when I was just a naïve young commissioner about five or six years ago, beneficiary pays made sense to me—the generator, the guy building the plant out in Western Pennsylvania is benefiting. He's making a heck of a lot of money. And whatever place he's paying the taxes is benefiting. And I was told, "Well, that's not how PJM does it." So, Speaker 3, what do you think?

Speaker 3: Well, part of the reason we're in the conundrum we're in, I believe, at least in PJM, is that the focus has narrowed to, "Its only cost allocation we're going to work on over here," and "It's only planning criteria over here," and again, there is this mentality [that focuses on load]. I think what Speaker 4 brought up in his presentation is, if you look at the measurement of what are the benefits, we're narrowed down to a production cost run, and not only that, a production cost run with very artfully crafted formulas to make sure that we bring out every potential extra benefit that we could--I mean, bring it out of the analysis so that it doesn't show up.

So the point is that I think, if you broaden your view of benefits, again, to include things like a more vibrant market, less market power, these other things like this, then yes, I think you need to broaden your view of beneficiaries. I mean, in any commodity market (and sorry, I still believe electricity or power is a commodity, which is its own issue), you have supply, you have consumers, and you have transporters. Then you have all the other people who operate in this vibrant market. And all of them are going to benefit from a more liquid market and less obstacles to transport, things like that. So I think you need to open that up a little bit. But if you do it, you need to open it up when you talk about beneficiaries, because then you have a much broader view of what would trigger expansion, and I think then that would lead to a broader view of where the lines actually show up.

And if you think about what Speaker 1 said, (and I'm sorry I'm taking so long), but you've got a 500 Kv system in PJM, which was relatively strong. You have obviously the Midwestern transmission in AEP. Between the two, there was really a gap, so that's why you're seeing a lot of stuff built across there, because it traditionally was not planned together. So that's where all the focus is, but frankly, there's a broader picture out there. So I'll stop.

Speaker 4: Well, sure, I mean, generators might have to pay for some of it, and some of them do under the interconnection cost allocation process, but the Organization of MISO States has recommended that MISO implement an injection/withdrawal tariff, where 20% of the costs would be recovered from injecting generators, and 80% from withdrawing load. MISO decided not to file it that way, and certainly here in the US we have a tradition of load pays, which has mostly been justified, in that if you charge generators, load will still ultimately pay, because they'll just pass those costs on in a power contract.

But I do think, particularly as you transfer power across regions, if you allocate some of the transmission costs to generators, then the generators in the exporting region would get some costs recovered from that, because between MISO and PJM, there's no pancaking, right? But should MISO be billing all the transmission of MISO generators exporting to PJM? Well, probably not. So you have to do something. And maybe allocating some of the costs to generators does make a lot of sense. It's certainly done in the UK, where 50% of all transmission costs are recovered from generators, and the other 50% from load on a zonal basis.

Speaker 1: I think one of the things that has to happen is that there has to be a recognition of differences between types of generation. The fossil fleet can really be pretty much located anywhere, and so it's appropriate sometimes for there to be incentives to locate in the right spot. When you have renewable resources, you can't change where the sun is going to shine. You can't change, really, where the wind is going to blow.

One of the things I think we just have to get better at is recognizing that there are these differences among units, and then therefore, for some of these unique resources, we might need to have some kind of a blending between generation paying and load paying. And the reason why I think it's important for load to bear some of those costs, quite frankly, is that you really want to make sure that you're building an efficient system. You know, I think that we all know here today that no matter how we do scenario planning, we're never going to get it right. And the one thing people don't want is a lot of extra transmission in their backyards.

If you're designing a system where it is 100% borne by generation, and you think of these collector systems, they're going to be undersized. They're going to be dramatically undersized. And is that the kind of transmission that we really want to encourage and have? Or do you want to have a more efficient and robust system that's capable of doing more?

I think one of the inherent differences sometimes between offshore transmission and onshore transmission is that offshore is a little bit closer to a single-purpose asset. And so that is much more tied to being just a straight generator lead. When you have terrestrial high voltage transmission, I think MISO got it right in the naming, it's a "multi-value project," and they do provide different benefits. They've got resource adequacy benefits, reliability benefits, economic benefits, public policy benefits. And when you think about that in light of the fact that no matter what we do, we're not going to get this quite right, you really want to make sure that the transmission that you're building is going to be useful, or has the highest probability of being useful, 20 years from now.

One of the stories that I often share is when we look at the AEP system, it was actually built based on projections of load growth, and there certainly has not been tremendous load growth in the Midwest since the 1960s when this system was first envisioned. But yet it's been the backbone of the PJM system. It's been a system, in combination with the 500 Kv system, which basically stops the blackout from occurring. So there are a lot of benefits associated with it. And so how to you quantify that, and how to figure out who should bear the costs along the way, is the problem that we really have to tackle.

Speaker 2: I believe that the beneficiary should pay, whether it's generator or load. I also believe that there are techniques for quantifying benefits. The problem is with getting agreement on it and doing it fast. But I do believe you have to do that. And I spoke about the integration of HVDC with DC, HVDC with AC, and what we found out is that there are amazing values you can derive from that in terms of grid operation, efficiency, and reliability. And this stuff is expensive. It's not going to come cheap. And to just do it, and then lay the costs on somebody entirely or disproportionately in one or two or three or four states is just not right. You have to go beyond that and allocate it to the others as well. And the criteria is that no one's bill is going to increase. So you do that kind of test ex ante, and you go with that type of decision.

Question: I'm not sure that I have a solution for the next five years, but I'd like to propose one for something between five years and the year Speaker 3 retires. First of all, we were discussing earlier that we can't get a feasible solution to the frequency problem in the eastern interconnect, and we're blaming it on bad data. I would argue first of all that the database isn't there yet to do Eastern Interconnect planning, and we need to spend a lot of time and effort on building the database. I don't mean to be nasty to PROMOD, but that's the model I'm most familiar with, and the data in PROMOD is sort of done on a wing and a prayer. We don't have good modeling systems. I mean, we have a lot of ways to test for reliability, but if you look at the PROMOD modeling system, and that's used by a lot of people, it cuts a lot of corners. So the state of the art modeling and data is together not very good.

The scenario debate is going to be interesting, and it's going to be difficult, and it needs a lot of discussion, and I'm not sure how that sorts out anyhow.

I would propose that the criterion should be expected economic efficiency. You can throw in value of lost load for reliability problems. That's the standard that's been used for years. If it's a federally mandated program, you can have SO2 cost. We fully integrated those into the system without swallowing hard. If it's a federal renewable portfolio constraint, we can put that into the model. The question is, how do you treat state policies, and arguably from this morning's debate, the cost of state policies should be assigned to states.

In some sense, if you pick the optimal transmission plan, the issue of transmission cost incentives goes away if you can penalize cost overruns sufficiently. So if you put all those together, I think you may be able to come up with a defensible system.

A couple of meetings ago, one of the speakers went through a cost allocation scheme, and he went through it quite fast, so people who are here may not have picked up on it. I would recommend you go back and look at it. It's a simple analysis. It probably can be expanded. The speaker didn't have the time to write all the equations down, and I'm not sure he's done that yet. But the analysis is on a standard two-dimensional graph, and it shows that it shouldn't be too hard to figure out in rough justice how much beneficiaries pay.

The current system has so many points of attack that it's going to be difficult to do things across states or across utility boundaries. And arguing a lot of these other issues, until you have a good database and a good modeling system, or a much better modeling system, is just going to create problems when it comes to cost allocation.

Speaker 4: Well, I think the kind of framework that was put out maybe at the last meeting is a helpful starting point, but I also think it's exactly the kind of framework that will get us nowhere fast, because to figure out how every generator and every load and every zone benefits from a transmission line, or a transmission system is much more complicated than any model will be able to handle any time soon.

Question: He didn't do that. That wasn't what he did.

Speaker 4: Well, I'd encourage you to look at my slide ten that lists a bunch of benefits. I think many of these benefits are in addition to the four categories that you mentioned. I think it's sort of stunning in some ways, because we have all these modeling capabilities, and then you realize that none of these model runs actually consider the reduction in transmission losses. You can sometimes justify half the cost of a new transmission line by just the reduction in transmission losses of that line, and nevertheless, people don't realize that these model runs don't factor in changes in transmission losses, even though it looks like they do.

So I think the whole thing is very complicated and I'm afraid if we really wait for the Eastern Interconnection-wide effort to come up with the modeling framework that does it all, we'll be waiting for a long time, because I don't think we'll quickly come up with a framework that can do it all. I think economic transmission planning is more like coming up with a business plan. If you figure out whether to build infrastructure for a new mall someplace, you're not going to run some big model somewhere. I mean, part of it is entrepreneurial intuition. Part of it is believing in benefits that you might not be able to quantify 100%. I think there are a lot of these kinds of factors flowing into transmission planning, but I do agree with you. We need to do a much better job of thinking through plans and figuring out which kind of plan is likely to be lower cost in the long term. And we just can't hope that there will be bright line criteria, like the ones we have on the reliability planning to really give us the answer.

Question: But even reliability doesn't have bright lines. I mean, the reliability argument starts off with a stochastic analysis that you pull out of your hat.

Speaker 4: Except we've been used to pulling that out of the hat for the last 50 years, and we're comfortable by now.

Speaker 1: Just a couple of brief comments. And probably this is because my background is in engineering, rather than being an economist, but I think there can be a tendency with these models to analyze things to death. And when you reflect on the history of our infrastructure, we've been building transmission lines for about 100 years or so, and we did most of it without the aid of computers and without modeling. We did it with a pad and a pen. And we justified it based on our intellect, based on the gut of transmission planners, and really, it hasn't been all that wrong. The system that we've got is a pretty darned good system. It's better than any system in the world. And so, when I think about some of the things that we've been doing over the past five years, it has really been a bit of analysis paralysis. I remember when I first started in my current job four years ago, I started talking about cost allocation. And one of the things that I would say early on is that I hope in five years I'm not still talking about cost allocation. [LAUGHTER] And I've only got a year to go here.

Question: So I'd like to follow up on the previous comment and observe that both Speaker 3 and Speaker 4 indicated a broader view of benefits besides production cost savings. I think that's a very reasonable thing. I'd like to check in with the panelists to see whether that would include LMP reduction and CO_2 decreases, in other words, those two things I was questioning on Speaker 2's presentation. And furthermore, if the benefits include reliability benefits, how do we quantify them, even abstractly? Even with a toy example, how do I come up with a number? And I think the last questioner suggested an approach to it, and I'd like to know whether you felt that was what you would do.

Speaker 3: The economic benefits analysis as it is done today in PJM, it looks at, of course, energy price reductions as well as reductions in congestion. Unfortunately, though, it also looks at energy price increases on the other side, which tends to obviously detract from the economic benefit, correct? So it's looking at the movement of energy prices around the system. And that's I guess OK if you went further and said, "OK, but the phenomena of the market converging in price like that [has value]." There's more to it than just measuring did the load payments over here go up and the generator payments over here go down. Because obviously, fundamentally, by the market reducing its separation, fundamentally that means the market is becoming more efficient, because there's less barriers to the economic efficiency of it.

So again, then we narrow our view and say, the way in which you measure benefit is looking at the production cost savings. And we all intuitively look at that, and say there's a lot more benefit than that. And I think the key is, yes, absolutely, you need to look at energy price differences. But you can get yourself caught up in this and end up carefully maneuvering around showing real benefit.

If you move to reliability, obviously looking at the change in capacity price [is one way to look at benefits]. Of course, as the previous questioner said, the value of lost load [is another way to quantify benefits].

I think one area that I would like to explore is this concept of operational efficiency. In other words, what kind of flexibility do you have operationally once a facility is in place? Did you reduce the dependence on complicated relaying systems, for instance? You know the term SPS--and it's a bad word in some areas of the country, and it's a bedrock of how you run the system in others. But those in and of themselves create risk because they're dependent upon certain systems operating. And I think the elimination of that type of operational restriction--again, are you going to be able to quantify it in dollars? I don't know. I think the answer is, of course you *could*. But it would be driven by assumptions, and the first three letters of assumption are…you tend to get people upset.

The bottom line is, I think, you can do this. We need a willingness, though, to accept that if we go down the road of trying to actually quantify the full benefit, it actually may result in stuff being built. And I think that in some cases, maybe that's not widely accepted, because once you build something, you have to pay for it. I mean, if you're asking analytically, I think the answer is yes. You can do those things. Obviously in respect the previous questioner's point, it's difficult to over-depend on models. You can take engineering analysis so far, and you can get so much out of it, and then you have to realize maybe it's time to be intuitive.

Moderator: I think maybe economists like modeling better than engineers, is what I'm figuring out.

Speaker 4: Oh, you should see how many models engineers have. [LAUGHTER]

Speaker 1: I think one way of doing it is taking a look at it from a tiered approach, and in the sense that you have tier one benefits, tier two benefits, tier three benefits. And you weight them, maybe, a little differently. But I think when you're looking at different scenarios, and you're looking at a series of different projects, you look at what are the total benefits associated with that, recognizing that some are not going to be as valuable as others. For example, CO2 reductions. If there's a tax on CO2, that's something that's very quantifiable. If there's no tax, it's still something good to do, and so that doesn't mean you discount it and throw it on the floor, on the cutting room floor, but it's maybe a lower-tier benefit if you don't have that hard economic number. So I think that's one way of doing it.

You had asked about reliability and how to value that, and one of the troubles, I think, that you can have is, say you've got a $1 billion project, and that $1 billion project is definitely a larger project. It's providing many more regional benefits, and so forth. It's checking the box in terms of CO2. I mean, you can just kind of envision this project. And then how do you compare the reliability benefits, because maybe it's not meeting a bright line test that someone like PJM would have? I think one way of looking at it is to say, "OK, if I put this asset in service, what am I deferring? What smaller reliability projects am I deferring? And when would I have needed them? How much are they?" And start discounting, in essence, that $1 billion project. So that would be a way of recognizing it.

Speaker 4: You asked whether LMP reduction should be considered a benefit, and that's a very hard question, because should you be looking at system-wide costs and ignore transfer payments between loads and generators or among loads? Or should you look at that? And I think the reality is, if you need to convince a state commission of the benefits of a transmission project, you cannot ignore factors that will affect what customers are paying. And if you build a transmission project between Western and Eastern PJM, and it increases market price in Eastern PJM, and the Illinois commission is concerned about higher power procurement costs as a result for the standard offered service, that will factor into their decision very heavily. So I think you can't ignore LMP benefits.

I personally don't like that, because the way you quantify LMP benefits is in a very, very static fashion. What people usually do is they take the system without the line, plug in the line, and see what changes. That is not realistic, because if you build a line between Illinois and Eastern PJM or something like that, you can integrate a lot more wind in Illinois, and the LMP increase that you would think happens from the line, assuming everything else is the same, won't be there because everything will not stay the same, and you integrate more wind, and that additional wind might actually hold LMPs the same or decrease it. So I think the overreliance on production cost modeling and LMP impacts actually creates a sense of winners and losers that is quite unrealistic.

None of these models have even capital costs in them. You don't even know how much you save from building transmission to a lower-cost resource, because all you count is production cost saving and SO2 cost savings.

Briefly, on the question of how to account for reliability benefits, well, the questioner said loss of load. That's certainly one aspect of reliability. You need a different model for that altogether. The PROMODS and GTMax, they can't really reliably do loss of load studies, but what they can do, and what is usually not done, is to realize that every once in a while you have extreme market conditions like what we just had in Texas over the last few weeks. Even if you don't lose any load, the prices are so high, you've got market power problems, you might have all kinds of costs imposed that are reliability related, so just running a base case will not capture these costs because the transmission benefits are disproportionately distributed into infrequent high-impact events. So one way of capturing reliability-related costs is to model these high-impact events. And American Transmission Company did a very nice cost-benefit analysis of its Paddock-Rockdale line, where they actually went out and simulated such multiple contingency events and so on, and they found that a big portion of total benefits are concentrated in those infrequent, high-impact events. And we could go on about these things for another two hours…

Moderator: We don't have that much time.

Speaker 2: Just about reliability, there are at least three types of situations you could face. One, there are some technologies that can accelerate restoration of load after a blackout or an outage, particularly what we call volt source converters. So for example in Manhattan, the latest estimates are that optimistically Con Edison would recover or would restore critical load in about four hours. If we have the technology, volt source converters, it may be minutes. We're looking into that. So how do you value that? Well, you look at the frequency of those kinds of conditions, and you look at value of service. A lot of studies have been done on that, so there's a way we can do it. So that's one type.

A second type of situation, if you have violation of reliability criteria, like the criteria B or even C, now, most transmission operators, they insure that these criteria are met. But what if a project that was scheduled to come online, but it did not? And that project was actually planned on the basis that it will avoid the violation of NERC criteria in 2017, say, but the project doesn't arrive in 2017? So now your project is going to be there in 2017. So what you do, you use the avoided cost concept, and there is a way of actually saying, if I can meet that criteria, and avoid the investment, and say sort of like a benchmark investment, so that's a second way you can do it.

The third type of situation, and the most problematic, is if you have a catastrophic failure that creates, for example, a three phase fault, it creates a blackout, it creates cascading, there are ways of actually evaluating that, and a study now is being conducted in the western connection. I have been involved in a study with EPRI where we looked at how we do that and simulate something similar to the 2003 blackout.

So there are three types of situation, and ways of evaluating potential benefits of transmission for each.

And as far as the energy, I want to go back and tell you that if you have wind energy being injected at very high levels over long periods of time at minimal cost, which is usually the O&M cost, so let's say less than $5.00, those injections are going to change the topology of the LMPs. You have no avoidance of estimating what that impact is on the load. Sure, some generators will lose. Evaluate their losses and net out the losses. So this transfer payment business is not symmetrical. There's always savings. There's always a benefit for the system, because there's less congestion. It's the congestion that creates monopolistic market conditions, excess economic rent. All of that can be recovered. So you have no choice but to go into this production cost modeling. Some models are better than others. And that's a situation that RTOs have to look at carefully and choose. Is it PROMOD, GTMax, etc. There are several tools there.

Question: Speaker 4, you had a point in one of your slides about state commissions lacking authority to consider multistate solutions, and I have to agree with that. The law that compels state commissions is, is it in the interest of the people of the state? And those conditions existed long before the RTOs. They certainly predate them. And they're still in existence.

So even if a state commission wanted to consider the broader implications of a proposed project, I would look to Speaker 1's slide on page five about the different allocation methods and look to ComEd on that slide and how the cost allocation using the DFAX method is $15.17 million. Under the socialization method, it's one billion dollars.

I don't think even if my legislature gave me the authority to look beyond the state, that this would even approach anything that could be characterized as reasonably commensurate benefits to cost. Hence our filing at the Seventh Circuit, and the relationship that we've all acknowledged has sort of thrown a little monkey wrench in the cost allocation going forward.

But this is the stark comparison that we're dealing with here. I am an economist. I still dream of that beneficiary pays concept, but I'm also a realist. I know that it's not… But when you look at these numbers, more or less, I'll see you in court. I think that's the stark result that I come to. And I'm not the only one. I mean, if you look through the relative distribution here…

So I guess I'd ask the panelists, I mean, what do you see as a solution of this, other than federal legislation to solve cost allocation, because to me, I see it as winners and losers among the states, given current conditions and future conditions. And I just don't see any agreement coming out of the states on this.

Speaker 4: Sure. It's exactly with this kind of table, when you rely on narrow benefit metrics, that you get these widely diverging results. The other issue, of course, is that this is about projects that are mostly in Eastern PJM. This does not include any sort of wind outlet transmission that would be built in Western PJM, and that's why I think when I say you have to do it on a region-wide planning basis, that's why it's so important. As long as you only look at a subset of transmission facilities in one part of your region, it always looks like benefits are unevenly distributed. Now, it might well be that you never have to build anything in Western PJM, but we already know that's not true. So a lot of these numbers will look very different if you add in the things that might need to be built in Western PJM to integrate renewables or whatever you have over the next 15 years, until Speaker 3 retires.

And I do think both of these metrics, the DFAX method, or the cost/benefit analysis that was done to support the postage stamp are just fundamentally flawed by exaggerating the winners and losers, because there are a number of benefits that are not captured in these metrics.

Question: That's a tough sell, I mean, to go back to a legislator and say that "We need to pay these costs now because intergenerationally, sometime in the future, we may have investments that someone else will subsidize…" I find that to be a --

Speaker 4: You're absolutely right. You can't do that based on speculation. In Maine, the political pressure didn't subside until the projects were actually on the drawing board, and people realized that enough needed to be built in Maine to even this out. And then the issue went away just as quickly as it came on.

Speaker 1: I would echo everything that Speaker 4 just said, because I think he was really spot on. I think that there's a couple of other interesting challenges associated with the western part of the PJM system, and I think one of them is the fact that particularly in Indiana and Illinois, you've got the MISO and PJM systems kind of floating on top of each other. And that creates a number of issues. And when you've got one RTO looking narrowly in one direction, and the other looking narrowly in the other, you've got two states that are trapped in between, and that's very unique compared to almost every other RTO. A lot of RTOs, it's a pretty hard line in terms of where the facilities end, if you look at New York/New England, New England/PJM, and so forth. So I think that there is a definite need for PJM to change the way it plans the system. And certainly to have much more of a western focus, because there has been so much…

We were actually meeting with the Indiana commission and talking. They were asking some questions just about the transmission system and so forth. And we talked about how much new wind has come into the Indiana area. And of course, we're also seeing flows associated with Illinois coming into the Indiana system, and that's putting a lot of stress on a radial EHV line going to Rockport. And there's a lot of coal generation sitting right there as well, and it's a recipe for disaster. We've got special protection schemes in place there-- undesirable. It's a ridiculous amount of generation sitting there on the end of a radial line. But it's the fact that it's the--I hate to say the butt end of the system. It's the tail end of the two systems right next to each other, and that is causing a problem. So I think part of it can be done with, an approach of, let's see what the rule making says. Let's see what it directs the RTOs to do in terms of transmission planning, and hopefully we'll have some changes there.

Question: Just one final comment, in the spirit of cooperation. We just haven't sued MISO yet on the MTEP. [LAUGHTER] We'll get there, Speaker 3.

Speaker 3: That's fine. I didn't want to do a me, too, but a lot of what they said, I would have said the same.

Question: The first question I have is for Speaker 2. In your presentation you made it very clear that you don't want to socialize costs for this offshore transmission and wind project, but who's going to actually then pay? Is it going to be allocated to the wind generators off shore? Is it going to be allocated to the load that's close to the coast? In what percentages? By what means will this be determined, etc.?

And I also just want to echo some of the issues that were brought up earlier in some of the comments on clarifying questions. But I'll add that if I take a look at the costs and benefits, and you talk about emissions costs--wouldn't those also be rolled into production costs, so you might actually be double counting those as benefits there?

Speaker 2: There are quite a few questions there. I'm going to rely also partially on Speaker 4 here as far as environmental costs and all that. But let's just use numbers here to illustrate the case. Let's say that for the wind itself, busbar cost, is 15 cents a kilowatt hour. Right? And that's less than those smaller projects like the one Cablenet set up. But let's say offshore it's 15 cents a kilowatt hour.

Now, they hand the title to the power to the utility that bought it. And they scheduled it into the system through our buses, through our system, which will be part of the PJM. They will put it into the system to cover their variable cost. There's no fuel cost, or let's just say for round numbers, it's five cents a kilowatt hour. So now that's five cents. They paid on a long term basis through a purchase power agreement at 15 cents, and that 15 cents, by the way, maybe came through a bidding process that's set up. So now, they represent the consumers, and they are in a hole by ten cents. So how do they cover that?

In part, let's say two or three cents go out because of OREC (the Offshore Wind Renewable Energy Certificate Program) or other incentives and taxes. Let's say that that's a total of five cents. There's still five cents missing here. All right? Keep that picture in your mind.

Now let's go to a little-noticed event I think is still going on, in a place called the Baldwin facility, I believe, I think it's 400 megawatts off the coast of Germany/Holland,. They have 400 megawatts. They have a converter. And they were feathering the blades of the wind turbines, because they didn't need that much power at certain hours for technical reasons. Well, if the wind was blowing at 400 megawatts, and they needed only 300 megawatts, that's called curtailment.

So there is 100 megawatts. Then somebody said, wait a second. We have marvelous electronic control over these things. We can recover the 100 megawatts at any moment. That represents spinning reserve.

Well, that's a benefit, and it's quantifiable. It's small. Spinning reserve doesn't cost that much. It's small. But our project, married to the wind, will produce incredible advantages for the PJM--because the mission of the PJM, in addition to keeping the lights on, is minimizing the cost. That's their objective function to everybody. The other mission is to make the market as flat as possible. And that means managing congestion in the most optimal way possible. But we still see a gradient. We still see prices very high in the North for most of the time and low in the South. With this machine, you can actually flatten that. And the only thing that would become the cause of any price differential is these marginal losses. And that's another issue. But the point is that you do achieve some benefits.

Who's entitled to those? Now, you have two scenarios. Either the states who invested in several thousand megawatts, they'll say, "We'll take it on the chin. We will absorb this missing five cents, because we have an RPS program. It's mandated. It's God given. That's it." The other scenario, they will say, "Our rate payers are going to recover whatever they can from the market, because we are serving the market." Now, when we did a simulation, we found these effects extend beyond the four frontal states. They extended to neighboring states. They do incur a reduction of LMPs. That's where the price is set for the load. So this is the value there, and we believe that value should be recovered. What's the mechanism for recovering it? We don't know.

As far as the Atlantic Wind Connection costs, it's a small part. The savings--we don't even count reliability. We're already cost effective. But we still have to have the wind come in.

Now, one more thing. The five cents, by the way, could be made up in another way, because only this kind of project will achieve hooking up ten megawatt machines instead of 3.6 megawatt machines. You have economies of scale that you cannot achieve any other way. If you go and rely on just radial investments, we will have showcase investments, a contract for 200 megawatts here in New Jersey and 200 megawatt in Delaware, etc., and every governor will be happy with his accomplishment. And he goes on to, well you know, other elections.

So we don't want to be caught in this situation. We want to keep this industry common, and that has to do with the other question with respect to the NOPR. When do you count? How do you create your scenario that says, I do have wind that will be coming in. It's the old chicken and egg problem. I do have it. And I have economy of scale. If I can prove to you from the manufacturers that it's not going to cost 15 cents offshore, it will cost ten cents because of the advances that they're doing right now. If it costs ten cents, then I broke even. I'm fine.

It is really a case of build it and they will come. They will come, because they'll make their money, and everybody will be happy. And I will not have to rely very much on pressuring other states on paying for it. But we can demonstrate, and I believe we can, there is value to be created, because this is a new technology.

Remember the old debate between George Westinghouse and Thomas Edison. Each one thought that one technology was better than the other. Thomas Edison said, DC is the way to go. Westinghouse said AC is the way to go. What we're saying is the combination of both can create some really amazing--I wish I had time just to tell you how it works. It can create value that's embedded and buried in the grid today.

Question: I'll just follow up very quickly on that. If I interpret what you just said, let me give you what I just heard in terms of the cost allocation. You're saying you don't know, but after all of that, I would interpret that as to say, "We're going to bundle the transmission and the wind generation all together. We're going to sell it together as a bundle, as a PPA to states. They're going to pay for it all that way, and we're just going to be done with it."

Speaker 2: No, I didn't say we're going to bundle. I'm not an expert on that. My gut feeling tells me you can do it this way, but I'm just saying that you have two parallel processes. Our issue is really at the RTEP, at the process of PJM. They cannot assume that the wind generation is available, except at minute values. If they plug those values in, in their simulation for, not just the RPS, but how much wind is going to come in, we will plug along with it numbers that come from the industry that say this is the busbar cost, and it's not going to be 15 cents. It will be ten cents. In that case, we're fine. And I don't have to bundle it.

I'm talking here about the planning step. OK? The other step, the cost allocation step, that still matters for our project. But will those who buy these long term purchase power agreements get some value accruing to them, because they have a good product? That kind of process doesn't exist or will require some improvisation in the PJM tariff and the settlement process. That's a separate issue.

Question: Thanks. Thanks for indulging me.

Speaker 4: Let me also just follow up on a couple of questions that were asked earlier. The emission costs are not double counted because they're not part of the production cost savings in these numbers. But I think we all have to realize offshore wind is going to be more expensive than regular power. And so you will never be able to do a cost-benefit study that says, oh, offshore wind is going to be cheaper overall, because you just won't be getting there. So the only question in my mind is, A) are we taking the RPS requirement seriously? B) do the Mid-Atlantic states have a preference for more expensive offshore wind over cheap wind from the Midwest? Can we actually get Midwest wind delivered at reasonable transmission costs? But ultimately if the decision is that we're holding onto the RPS standards, and we are relying on offshore wind, then the question becomes, how can we get that done in the most cost-effective, biggest scale economy fashion? And I think we've actually done some of that economic benefit study that AWC filed at FERC, and it's going to be a big challenge.

But getting to a larger scale is going to be critical, because we know right now offshore wind costs $180 a megawatt hour or more. And we can't afford too much of that at that price. But if we can get scale economies and local manufacturing incubated by a commitment to RPS standards, and maybe a transmission solution that's more cost effective at sufficient scale, then we might be getting there. Otherwise we'll just get stuck in the middle where we spend a lot on it and get very little for it.

Question: I want to touch on something we spoke a little bit about before. When I look at the discussion this morning and this afternoon, kind of the overarching theme here seems to be not so much cost allocation, but an issue of risk allocation. On the generation side, we heard this morning how the LS Power filing to FERC is indicative that even though they say their costs are lower, what they're looking for is the price certainty. So they don't like the market design. They want to unload some of that risk. That risk has to go someplace else. It goes to consumers.

The discussion we're having this afternoon, despite the fact that transmission construction, if I remember my EI numbers correctly, since the beginning of the century has more than doubled on an annual basis, yet we're talking about lowering the bar for reliability projects, lowering the bar for economic projects, and introducing a new aspect that builds for policy despite the fact that we do not have a national price on carbon. We do not have a national RPS. And we haven't seen the states clamoring for additional transmission to help get their renewables built.

So I guess my question is, given that, and the fact that we're asking consumers to pay more and more for this, is this really enlightened policy and the direction we want to go? And how far can we take this before consumers or those who represent consumers just say, "We have to stop here at some place. It's just getting too expensive?"

Speaker 1: I'd like to speak to the comment on the transmission front and how much we've been investing. You know, I think we've heard repeatedly from Chairman Wellinghoff, and certainly from the federal legislature with the passage or EPAct 2005, that there is a need for more transmission investment. Now, I think that transmission investment has picked up, but a lot of that, when you look at it, has been more of the break and fix, or replacing existing assets than it has been in new transmission lines. If you take a look, and I wish I had the statistics with me, but if you look at actually new miles of transmission line, it's a very unremarkable number. And particularly if you look at new miles of VHV transmission, it's even less remarkable. Just speaking real briefly, in terms of SPP, for example, you can't move a megawatt from Western Oklahoma to Eastern Oklahoma. I mean, that's ridiculous, and that's all part of one integrated system.

So there is a tremendous need for transmission, and so the question is, what's the right amount of transmission? What is it, exactly, that you need? And I think you do have to recognize the fact that the different RTOs are in different stages of evolution, and some have healthier systems than others, certainly. But I think to say that there's been a tremendous amount of transmission investment is an overstatement.

Speaker 4: The last questioner raises a very good question, and we all would like to know the answer to that. How much can we spend on transmission and renewables before there's a backlash? And you know, I fear the backlash will come sooner than we expect, so I think we all have to be very careful about how to proceed. And that's why I'm thinking you cannot proceed on this without the states being fully behind it, because the states and the state commissions have an obligation to protect consumers to some extent, and to implement public policy, and I think as long as the states can agree that in the overall scheme of things, it's cost effective to do that despite rates going up, then we'll get there. We can't build transmission or build a lot of renewables without having the states on board. It will just not work.

Question: I just wanted to clarify the issue on LMPs. The criterion for building a line is net expected social benefit with all the environmental costs and reliability costs. The criterion for cost allocation uses the LMPs. The LMPs are not used at the stage of deciding whether to build the transmission line or not, or the group of transmission lines, but the LMPs are definitely used for the cost allocation portion.

Speaker 4: Well, you know, that's not quite true. There are some tariffs, like the PJM tariff and the MISO tariff, where production cost savings and LMP cost savings are weighted 2/3 to 1/3.

Question: I understand there are existing tariffs. I was proposing a system five years down the road.

Speaker 4: Oh, yes.

Question: And I would also argue that given the position of Congress and the Seventh Circuit decision, if you're going to go on a collision course with the Seventh Circuit and the Corker Amendment, you may end up with the worst alternative and trying to move in a different direction.

Speaker 4: Could you clarify what you have in mind?

Question: Yes. It's going to come back. There's a very high probability that the current system is going to come back into your lap from one of the circuit courts and tell you to start over again.

Speaker 4: Sure. You know, I think we do have to be very conscious of documenting why cost allocations make sense, and we can't shortchange that. It would be a huge mistake. I do have a problem with the Corker Amendment, in the sense that you can only rely on measurable benefits to one or more persons. I think that's just an unrealistic standard for beneficiary pays, because even current utility-level regulation doesn't work like that.

Question: I think you are misinterpreting the word "persons.." Person in this sense –

Speaker 2: Entity.

Question: A corporation is a person.

Speaker 1: Legal entity.

Speaker 2: It's an entity, basically.

Question: I think this is just legalese.

Speaker 4: Well, that might be, but even that is going to be very challenging.

Speaker 2: About the comment on the use of LMP in cost allocation. Using the LMP is inevitable in the cost allocation. I predict that, unless the NOPR goes in the wrong direction. It's not really that difficult. You've got LMPs bus by bus, for generator, for consumer, for load take off. The only issue is, when you have two projects affecting service areas that don't use LMP platforms, so you have these interregional issues, nasty ones, particularly if you have one that uses LMP market platform, and the other one doesn't, then you have to figure out a way around that.

Moderator: OK. I have a question, because nobody else has a question. There's a planning process that obviously everybody knows is going around the country. There's the EISPC (Eastern Interconnection States Planning Council) process that 40 states or so are involved in, and there's also the planning units for the three areas. How does that impact cost allocation down the road?

Speaker 3: I think it kind of started out with the state buy-in being a way to get, I'll say movement, or to some extent agreement, and I think we've seen examples of that occurring. So if we had a do-over or a start-over, potentially that could trigger that process stepping into the void. That's one potential outcome. Of course, we don't know if we're going to get a do-over or not, at least in the PJM part.

So you obviously have the regional plans, and then you have an interregional overlay, so to speak. I think that, again, gives you an opportunity, if you will, to have cost allocation on an interregional basis, where we agree to sort of go by the global regulators. Now, whether that would ever happen, I have my own opinions, but I won't go there…

But if in fact it can move beyond just being a way to project information back and forth--information coming from the states on scenarios, information coming back from the planning entity on what the scenarios would result in--if it ever would go beyond that, I think the only way, again, is if we had agreement, and if there's 40 entities, whether that would happen or not, I'll defer to my colleagues.

Speaker 1: About a month ago, I was at a National Governors' Association meeting, and a gentleman from DOE was talking about the EIPC (Eastern Interconnection Planning Collaborative) initiative. And one of the things that he said is that what he hopes to get out of it is a model, basically a base case of the Eastern Interconnect, and a common vocabulary. And I think that those are good goals.

I agree with Speaker 3. I think there is an opportunity for synergies. There is an opportunity to take a look at the systems and figure out maybe some simpler solutions that are benefiting multiple regions. I will actually go out there and say, do I think that's going to happen? I don't think it's going to happen, at least not in the short term. But I think what we will get is that model and a common vocabulary, and maybe each of us will have a better understanding of the different opinions around the table.

Speaker 4: You know, the whole planning process was very smart to explicitly not go into cost allocation. So this is only planning without any attempts to resolve cost allocation. And I think the planning process would be very helpful to help the regions coordinate with each other. But I also think there's a big risk that we will all wait for those Eastern Interconnection-wide plans to tell us something. We'll wait for the next three years, and then we'll get a 200 page report, and other than having a common vocabulary, we are not really any further along than where we are now. But as I said, I don't think we should wait for that. I don't think we should be too optimistic that much will come out of it beyond coordination between regions, which by itself is important enough. But that's not where most of the action is right now on transmission planning.

Moderator: And we'll hopefully get a model out of it that people will agree to in that area. But then, you have issues with models being able to factor everything in.

Speaker 3: And hopefully they won't lose their funding before it happens.

Moderator: Well, that's true, too. But I think it's a very costly exercise. And it's costing a lot of money. It's taking a lot of people a lot of time--not me. But a lot of people are spending a lot of time on this, and hopefully it will be worthwhile for us, but the timing of this is an issue.

Speaker 4: Yes, and the cost issue is a very serious one, but we have to consider, if we build a billion dollar transmission project, we probably spend $100 million on engineering and then environmental studies. And if we spend a million dollars on figuring out whether it makes sense to build it in the first place, would that be too much? I think we just are used to doing a lot of analysis on the environmental side and on the engineering side. But if we want to justify projects economically, we have to get used to doing our homework there, too. And of course, you need models, but what I object to is trying to shortcut things by just running one model one way and thinking you get the answer from it.

Session Three.

Nodal Real Time Pricing in the Wholesale Market: Nodal Real Time in Retail Pricing?

Wholesale rates are set by the FERC while state PUC's set retail rates. While that has not always been problematic, it has led in some instances, most notably in the California energy crisis, to serious anomalies and problems. Are we facing such a problem if the FERC decides to implement nodal prices for demand side bids without fully coordinating with state PUC's on retail pricing? How could a retail customer paying average cost rates get the appropriate signals to motivate him/her to contemplate demand response if the wholesale price signal is never passed through? How could a retail customer curtail his/her demand and receive the appropriate level of compensation at a particular node? How could the user of an electric car be incentivized to charge off peak without the appropriate signal? How much of a problem is this? Will the effect of non-reflective wholesale and retail rates significantly reduce the level of demand response, or increase the amount of inefficient use of energy? What potential is there for customers or aggregators to arbitrage between the two pricing regimes? Are significant market distortions possible? How might FERC collaborate with PUC's to assure coordinated price signals? Should FERC condition demand side participation on real-time retail pricing? Will state mandated energy efficiency programs be enhanced by fully coordinating retail and wholesale prices?

Moderator:

We're going to talk about real-time pricing at the wholesale and retail level this morning. And I want to take just a few minutes to set the stage with a few observations before we get into the panel.

First of all, this is something where we know that if we can go to real-time pricing, there is a tremendous potential benefit. Most of us have seen the studies of the pilot programs. When you combine a dynamic price of some sort with enabling technology, you can get 20-40% reduction in residential peak demand. And that may even understate the potential, as we know that there are lots of flexible loads, loads that either have thermal inertia associated with them, or loads that are schedulable. Think building, heating and cooling, water heating, pool pumps, refrigeration, also potentially to some degree clothes drying, dishwashers, or things that are schedulable, like charging electric vehicles or various batch processes. And the cost of doing that, if we can get the price signals to those devices, might be as little as a dollar or less to put the chip in each of those devices that could enable it to intelligently respond. So we have a potential game-changer here in the industry that we need to figure out. To what extent can we make it real?

We also are increasingly experimenting with the kinds of pricing that might allow various forms of very dynamic pricing to go down to mass market customers. We know that what we have to do in doing that is provide the dynamic price signal, address the potential loss aversion issues with consumers placing a high value on avoiding that one month of very high bills, and create pricing alternatives that are sufficiently transparent that they also promote competition in the market.

Just to briefly mention two of the experiments that are being planned in my own state, we're looking at an experiment with a two-part pricing program that would be a consumer subscription-type program, which would combine a dynamic price signal with a call option that would enable consumers to turn any very high prices in effect into a rebate, so long as they were using less than the call option, and the prices were above the strike price on that call option. This also has the very nice benefit that consumers could have a number of kWs in their option that was consistent with their own individual peak demand, or they could have choices to have a higher or lower call option and thus greater or lesser insurance, kind of like buying minutes on your cell phone to protect themselves against that high bill.

We're also working with one of our utilities on a real-time pricing double auction experiment that would provide consumers with a simple slider to choose between comfort and savings while various appliances that had some thermal inertia were automated to respond to those signals. And it's very similar to the pilot that was done on the Olympic peninsula where this kind of dynamic real-time pricing was among the most preferred pricing options for consumers in that pilot.

So we had some ways to implement real-time pricing that we can begin to look at, and we're beginning to collect data about how to do that. We have discussed here in this group in the past, how to integrate wholesale and retail markets if you're doing price responsive demand in terms of including forecasts of that price response in the operations and capacity markets at the wholesale level, recognizing that you still have to do something in terms of reserves, or an interruption price when you're in a generation emergency, but you can in effect recognize that price responsive demand in the wholesale market. You also need to do something in terms of scarcity pricing to address the price cap issues, and you need to figure out that this is load. It should be treated in a non-discriminatory manner, with other load that's not price responsive in terms of when you actually get to a generation emergency, so that you're curtailing based on relative capacity deficiencies.

And all of these issues, along with the DR compensation issues are issues that are before FERC today, and have been actively discussed, at least within PJM, and I suspect elsewhere as well. So these are the range of kind of foundational things that are out there. I'll mention one other thing, and that is within the smart grid interoperability panel in our business and policy domain expert working group, we're also taking a broad ranging look at how do we begin to remove the barriers to getting dynamic price signals down to home energy management systems and appliances and identify all of those things. And that's an ongoing discussion to try to identify additional barriers.

Speaker 1.

The California ISO's wholesale market, like many of the organized wholesale markets around the country, has locational marginal pricing as an effective means of dealing with congestion on the system, and therefore we price based on the geography of the system. The question that I'm going to talk about mostly today is the degree to which passing on geographically those wholesale prices down to retail makes sense or not. And this issue has been called load granularity here in California.

So a little bit of background, then. Currently, since the ISO's LMP market has begun, on the load side, they aggregate up the nodes into what are called load aggregation points, and those are currently consistent with the three main investor-owned utility service areas that are covered within the ISO. And they basically use load weighting to take the prices and create this load aggregation price. Generation, of course, is paid based on where it is locationally in the system, and changes in generation are the predominant means by which congestion is being resolved.

But based on direction from FERC, the ISO proposed in the fall a move to greater load granularity potentially to satisfy the FERC order to increase our granularity by April 1st 2012.

After some probably unexpected reaction from market participants, the ISO put off or wants to put off that plan by a year. But the concept is basically to move from the picture on the top, which basically has three prices, to what could look a little bit more like the picture on the bottom. I mean, I arbitrarily broke up the service territories into larger numbers of sub areas. But that's the point that we're looking at here--would we send prices through on the wholesale level to customers on the buy side based on this greater granularity?

Well, there are impacts associated with this geographical dispersion of prices that need to be considered carefully before we go down this path. Right now there are issues associated with the way retail rate-making is done that have to be considered before we can assume that by changing the way prices are passed at the wholesale level to buyers, that in fact these price signals will make it to customers. For example, right now, the public utilities commission that sets retail rates for California doesn't geographically distribute rates. Well, if in fact the public utility continues to not geographically distribute rates, but at the wholesale level we do start differentiating rates geographically, then for customers who have choice, we're going to create some new and perhaps unintended consequences.

If you have a choice, and you're served by the utility at an aggregated price, and you happen to be in a low price area, you could take advantage of that only by leaving the utility service. Of course, conversely, if you're in a high priced area, you would want to be under utility service, and that's just going to be exacerbate the differences in prices. And that's not really the reason why we would want people choosing utility service or not. So that's certainly one important unintended consequence that would exist, if the PUC didn't decide to follow in this path of geographically distributing rates. And currently they don't.

Interestingly enough, one of the things that will come out of this is that retail rate-making is complicated business. Others here are more expert, but I know just enough about it to be dangerous. And one of the many elements of the rates in California, for instance, relates to when customers leave our service to go to direct access, and there are certain costs that have been incurred on their behalf that are to be applied to them. Well, the current mechanism we've got, for instance, to handle these costs is to calculate this departing load charge based on a concept of indifference--the customers that remain should be indifferent to the impact of the customers leaving. Well, if that's actually going to be the case, then in effect, that mechanism will partially undo whatever the benefit is of leaving the system to take advantage of the low wholesale prices, because you're going to get a charge that leaves the remaining customers indifferent. So what I just said about how the remaining customers may have to pick up higher costs, at least to some degree, that's going to be offset by this rate-making component. That's an example of some of the complexities associated with retail rate design that have to be worked through before one could even really consider effectively geographically differentiating the rates.

And here is perhaps a more significant one. Overall, in order to make this change, there are going to be a lot of costs that are going to be involved, and we have to get an understanding of what really we're going to see in terms of benefits. And it's worth noting that the energy component is just one part of the total rate charged. We know that absent the kind of issues that our moderator talked about earlier that I'll touch on a little bit at the end, price elasticity of customers actually seeing and responding at the retail level to a lot of these prices isn't really that great. So changing this one component of the rate might not do what we might want to achieve efficient pricing.

Furthermore, we have to step back and think about whether or not we're actually improving price efficiency, even if we did geographically differentiate rates based on the costs in the wholesale market. California prices right now have this tiered structure where most of the customers pay at the tier one and tier two prices that are essentially frozen, so that when rate changes occur, they'll only be occurring at the higher tier for our residential customers. So what that means is, if you are one of these higher tier customers, you're paying pretty high marginal rates to begin with. And if we define rate efficiency as essentially trying to charge based on the marginal cost of producing, well, if you're in one of these high tiers, and you're actually in a high priced area, so that you would get an even higher rate, then you haven't actually improved the efficiency. You've just moved farther away from the actual marginal cost of producing because of the underlying rate design. The point being that retail rate design is going to play a critical role in the impact of this geographical differentiation of prices.

Much of the benefit that we might be trying to achieve in sending better price signals through can be captured today. For example, demand response often is and should be considered as an alternative to supply. It may be on the demand side, but it's really competing against supply resources. Well, the demand response programs do reflect currently the geography of where that demand response is in the system. So we don't need to make a change to the way we handle wholesale rates geographically overall to capture this differentiation on demand response.

On the other hand, there are important uses of temporal rates that I think can capture much greater value, and the metering to capture that is being put in place in California today. Edison has already got over two million smart meters installed, and by the end of 2012, it will have 4 ½ million, basically the entirety of Edison's customer base. So what if Edison did take these wholesale price signals and differentiate them geographically. What would it mean? I believe that Edison would actually be likely to see some pretty limited benefits from doing so, even if they could handle all the rate issues. And that's because the differentiation geographically isn't really that great, and the kinds of decisions that may be made based on geography would require great differences.

Here in what I'd call the heat map of California, if we looked at the 2010 average prices geographically across the system, the purple and blue are $30 and $32 a kilowatt hour, ranging up to the red at $40 a Kilowatt hour. They're in $2.00 increments on the graph. And the circles represent where the population is concentrated. So one of the things you see is the biggest difference across the entire state is maybe $10, or actually more like $8, from a low-priced $30 area to a high priced area. So we're not talking about large differences. And those are across vast distances. If you look within the areas, especially where the population is, inside those circles, there's virtually no differentiation at all. So then we have to ask ourselves, if we did have geographically-differentiated prices, what actions would customers take differently? The small differences, again, are not going to factor the way through in terms of price elasticity very much, and do people make the kind of decisions based on geography that are going to be impacted by these small price differences? And I would suggest that they don't, that if one has a business that is very sensitive to electricity prices, the reality is, you're probably not located in California anymore anyway.

On the other hand, across a day, the lower graph shows average prices for the year on a time-differentiated basis, and there you can see, even though this is all averaged out over the course of the year, there's still a $20 difference between the lowest prices in the day and the highest prices in the day. There's perhaps some real value to capturing some of that time difference.

Imagine that you did actually differentiate between neighborhoods in electricity prices. Would that really make any difference to the kind of decisions anybody makes? Not really. You're not going to move across the street because you might anticipate a one cent a kilowatt hour difference in your electricity rates.

What if we wanted to do geographic price differentiation anyway, though? What if we decided we thought it was the right thing to do? There are a lot of challenges to implementation that have to be considered--the costs of changing our systems to do this geographic differentiation, potential conflicts with other state policy objectives. You know, if the CPUC really thought that geographic rates shouldn't be distinguished, they have the ability to effectively, through the distribution rates on the system, undo what would happen to the power charge. So there needs, at the very least, to be coordination in what we're trying to achieve between the ISO and the CPUC before moving forward.

And then there are all these costs. What about forecasting? Getting down to the nitty gritty, the people who forecast the load who would have to now forecast on this more granular basis, would their forecasting be improved? Obviously it would require a lot more data and more effort. In short-term forecasting, the biggest thing that contributes to what's going on is the weather, and frankly, we don't have the ability to distinguish our weather forecasts within neighborhoods very well. So we would not anticipate having the data to do a better job forecasting at these more granular levels. For long-term forecasting, the benefits of doing that subregionally are speculative, but there is the potential that you could get better forecasts eventually at this more granular level, but it's going to be a while before we have the historical data upon which these long-term forecasts are based to do this kind of forecasting. So the challenges are significant, and the benefits don't seem to be that great.

So I'm just going to conclude, basically, with looking at where there probably is some real value, and this is consistent with what our moderator was talking about in his introductory remarks, associated with passing prices through to customers. And ultimately I think that is to take advantage of the technologies that are now becoming available between the smart meters and the ability to effectively passively send through these signals so that the equipment itself can respond, rather than individuals having to make constant decisions based on what the electricity price is. Ultimately, then, the elasticity benefits can be captured through technology and not through things like geographic differentiation of prices. Thank you.

Question: I have a quick question about what you described at the very beginning, and that is FERC's requirement to make this more granular. And it seems odd, because I think in a lot of states, the pricing is usually set by jurisdiction of the IOU. Can you just describe briefly what the FERC had required and why?

Speaker 1: Yes, well, again, FERC's not trying to make a determination about what would happen on the retail end, but simply how the wholesale prices would be passed through to buyers. When we made plans back in 2001 and '02 to go to an LMP system, the concept was, that you're going to have 3,000 nodes, and we're going to send 3,000 prices through to the buyers and sellers. And initially there was some resistance to doing this on the buy side from the political process, and so the determination was, well, you know what? Let's not delay our movement towards LMP pricing based on this. We will do this load aggregation thing to start with, and then we'll look at going to more granular loads later. But it was always just sort of part of the assumption that if we're going to have all these prices, we should be passing them through to buyers and sellers. And now I guess we're starting to question whether passing them through to buyers in this way ultimately makes sense.

Question: Two clarifications. And anybody can answer the first one. Probably eight years ago, we had the Oxy Chemical decision in Maryland that large individual loads could become their own LSE and become a nodal customer in PJM. Is that the law across the country? Because that, obviously, interacts with the dynamics of how you're aggregation is. And the second thing, which is for Speaker 1 specifically, you had the average price chart across the state. Would you give people an indication of the difference in the marginal costs against your five tiers? PG&E only had three. I didn't know you had five. But from bottom to top--I think people will be shocked to see the differences.

Speaker 1: Yes, I mean, just going back to that chart--and it can get worse over time, because any new costs that come in are going to end up in the top tiers. But what we're looking at here is tiers one and two are roughly, it looks like 12 and 14 ½ cents, and then we're up in 23, moving up to 32. And that's Edison now. Increases in rates end up exacerbating that by going to the higher tiers. I believe that PG&E's tiered structure reached as high as 45 or more cents. They're very significant.

Moderator: And does anyone know the answer to the first question?

Speaker 1: I believe that the ability to leave the host utility still is sort of a state jurisdictional issue. Now, once you have left that service, how you are formulated--my understanding is that that may be at the federal level consistent with the way you represented it, but I don't know for sure. That's just been my understanding.

Comment: In theory, they could become their own scheduling coordinator at the Cal ISO. The problem then is, you know, what happens to your mandates for renewable portfolio standards or storage standards? And so there are added levels of complication from doing that.

Question: But legally they're entitled to do that?

Comment: I don't think there's anything blocking them from forming an entity to become a scheduling coordinator. But it doesn't mean they're not a customer from the CPUC as well.

Question: Just two clarifying questions. The LMP heat map that you showed is on an average annual basis. Does the relative lack of price differentiation also hold true on an hour by hour basis? Because I would think something like critical peak pricing would affect a small number of hours that might be much more geographically diverse.

Speaker 1: Right. You're correct. There may be times during the course of the year when the differentiation becomes much greater, and so to the extent one is reacting to real-time prices, and you have the differentiation on top of that, then you may be able to take advantage of spikes that are occurring geographically in one place when they're not in another, for instance, to achieve some efficiencies. Of course, other decisions that you make are really going to be affected by the average rate over the year, and you would need to first have time-of-use pricing to be able to take advantage of the spikes that occurred geographically differently. But you're correct.

Question: The second question is that this was all about LMPs. What about the Resource Adequacy Zones? Don't you have LCR (local capacity requirement) costs that are very different in different parts of your service territory?

Speaker 1: Yes. And, again, at the retail level, even if there are cost differences right now, we don't pass those through to retail customers on a differentiated basis. Distribution costs are different in different parts of the system as well. We don't pass through that on a geographically differentiated basis today.

Question: Can all retail customers in California choose another supplier now? Can anybody do it?

Speaker 1: There are limitations on the volume that retail suppliers can choose. So your limitation is not based on the type of customer you are, so much as that unless you're in front of the line, if we exhaust the volume that's allowed at any point in time, which is gradually expanding, then you can't choose. And that seems to fill up almost immediately once it opens up.

Question: Is the time-of-use rate that you allude to a dynamic rate in the sense that the rate changes with changes in the wholesale market? Or are the rates in each time period known well in advance?

Speaker 1: Well, in order to capture the kind of stuff that the previous questioner was talking about, you'd really need real-time prices passed through rather than just time-of-use rates. The metering would allow for either, but ultimately the rate design at the retail level by the PUC would have to be established and put in place, and we're not there yet.

Speaker 2.

I'm going to spend a few minutes talking about getting prices right at both the wholesale and the retail market level. And the proposition, I think, is not a new one--that we can't get pricing right at the retail level unless and until we get pricing right in the wholesale market, and that wholesale market pricing today is broken for a variety of reasons, with inelasticity of demand as one significant reason.

I actually see Speaker 1's presentation on more granular pricing as part of the puzzle and part of the strategy to get pricing right at the wholesale level. I totally agree with Speaker 1 that there are very important coordination and timing considerations to be worked in, but I don't necessarily agree that we should therefore not do it. And I'm not sure that you're suggesting that. But I think granular pricing is part of getting wholesale market pricing right.

So my premise is that pricing in the wholesale markets is broken because of a market failure, which is that we have insufficient elasticities of demand. And also, the FERC has properly set itself on a course to get wholesale pricing right—to do what the late professor Kahn said in comments on the FERC compensation NOPR, when he said that FERC should attend to its own knitting, and fix the problems in the wholesale market. And FERC has been pursuing this in several orders, to help fix these inefficiencies, by removing barriers to demand response.

In the NOPR on compensation I just referred to, FERC succinctly stated what really had been established as national policy on a piecemeal basis through several orders in individual ISOs, and that national policy is that there are two distinct forms or species of demand response. And that both (it said this in the Order), both can coexist in the wholesale market, and both will improve inefficiencies in the wholesale market. Frankly, my personal opinion is that we need both, and we should have both, and customers should have options to pursue both.

The first of these is, of course, demand side reductions, customers responding to real-time price, or having rate structures available to them to use less energy during high price periods. Everybody agrees with this. This is not controversial, really. But there is controversy *surrounding* that, because again, there's this disconnect between wholesale and retail pricing. We can't get an efficient tariff or contract rate structure at the retail level if pricing is broken at the wholesale market level.

There are transition problems that are very significant. Speaker 1 touched on a few of those with respect to granular pricing, rate shock, and customer aversion to pricing risk. These are significant transition issues. And the first form of demand response is largely a retail function. FERC's important role is to get pricing right at the wholesale level, but as it relates to this form of demand response, it should largely get out of the way. But if FERC only does that, again, if it doesn't fix the wholesale pricing issues, we won't see the situation improve, because again, the transition issues are very challenging.

So I think we have a stalemate, and I think FERC believes we have a stalemate, which is why FERC seeks to address that stalemate to pursue the second strategy of demand response, and that is DR as a *resource*, often referred to as a supply resource. And I will refer to it in my comments as a supply resource, a supply resource that is integrated into the market, as I said, on a supply side.

What FERC articulated in the NOPR order on compensation was that the national policy, as I said, was to have both forms of the market working in harmony with one another and not in conflict. Now, there is more controversy around demand response as a supply resource. It's new. Change is hard--threatening for many incumbents. And so that alone creates controversy. But other areas of controversy include the tendency to treat demand response--again, that is integrated as a resource in the market, as opposed to reduction in demand--and to still revert back to treating that resource on the demand side of the equation. The battle line has been drawn most recently around compensation, as we await the anticipated final rule from that compensation NOPR.

Now, the implications of treating demand response as a resource in wholesale markets is that it must have comparable obligations and opportunities. I'll get to opportunities second. ENERNOC is quite OK with that. DR that is a dispatchable supply resource should have comparable obligations. This includes not only rigorous M&V, metering, reliability obligations, financial assurance, penalties--all of these are imposed upon supply resources committing resources to the market, and they should equally apply to demand response resources.

But in accepting all of these obligations, DR as a supply resource must have the same opportunities as other supply resources, and it's not appropriate to deny these opportunities by reverting back to this formulation that DR, (again, acting as supply, sorry to sound like a broken record), should be treated like a reduction on the demand side. It really does result, as I'll point in a few moments, in a *non sequitur*.

These opportunities for demand response as a supply resource come up in two contexts most often. The first context is market access. If demand response can effectively compete as a supply resource, it must have access to the same market opportunities as other forms of supply. And that is what FERC is headed toward in FERC Order 719 in its provisions on demand response. Traditional supply resources have access to several value streams--energy ancillary services, capacity, or resource adequacy. The generation unit will then operate to maximize its economic opportunity from these revenue streams according to physical characteristics, fuel source, and location. Now, if DR is to become, again, an effective competitor as a supply resource, it needs access to these same opportunities. And the barriers to that access need to be removed.

Customers, like generators, have different attributes. They have different ramp rates. Generators often have a minimum run time. Demand resources may have a maximum run time. They may have times when they're available. They may have times that they're not available. So they have different attributes, too, and they need to be able to maximize the revenue available, the same as other forms of supply in the market.

We do not have access to these opportunities across all markets, and where we do, there are still tremendous barriers that have prevented this level of growth that would be efficient. We would not tell a generator that they can sell capacity, but they cannot sell associated energy and ancillary services. But we continue to do exactly that with demand response that is acting as supply.

A good example of this is in ISO New England, where demand response can today participate in the ancillary services market using what's known as DARDs or dispatchable asset-related demand. But if it does that, it cannot participate in the forward capacity market. So it doesn't have access to that revenue stream, again, acting as a supply resource.

The other way that access to opportunities for demand response on the supply side comes up is in the area of compensation. I'm not going to relitigate the NOPR here, but I am going to say a couple of words. If you are going to impose the same obligations on demand response as on supply, you have to compensate demand response as supply comparably.

When I say "demand response as a supply resource," it's just easier to think of it that way. What I am really referring to is the service that demand response provides that is substitutable for what a generator provides. And the value to the market for that service is the same as the energy or capacity that a generator provides. And if it's truly going to be treated as a supply resource and have all of those obligations, it must have, not only access to the same revenue streams, but comparable compensation as well. Again, here in the area of compensation, there is a tendency to want to treat DR supply like a demand reduction and therefore discount the value of the resource. And I think that's where folks have joined the issue. In my view, doing so undervalues the demand response as a dispatchable supply resource.

I will close with this. It is sort of unquestionable now that it's national policy that demand response will have opportunities to participate as a demand-side reduction and a supply resource. We need to fix the pricing inefficiencies in the wholesale market. Over time, customers should have the opportunity to pursue whichever approach is appropriate for that customer. The two approaches can coexist, and both can function toward achieving market efficiency.

Speaker 3.

What I'm going to do is take a little bit different tack. The agenda on my slide here expresses my interest in talking about eight different items. It's a pretty broad scope that I'll discuss, and certainly it touches a lot on markets and the same kinds of things that Speaker 2 and the rest of us are going to talk about.

Let's go ahead with demand-side in context. The basic idea here is that demand response can be thought of as a composite option, and it is a derivative product. So, as Hung Po Chao has said, it's a dispatchable product. It's both capacity and exercised energy. And voluntary and dispatchable DR results in major price impacts. So I think that's where we have the big problems.

So there's two questions. How to fully integrate DR into ISO/RTO markets, which Speaker 2 has talked about, and how to integrate retail and wholesale markets.

I will make the statement that these markets are not currently workably competitive, particularly because ancillary services don't reflect the cost causation that's needed in the market. This is something that people have talked about since 1998 and before. We don't have ancillary services that really respond to cost causation--the people that cause those services to occur don't have to pay for them. So we have really a huge and important element in the market that is socialized. To me, that needs to be fixed.

The other major distortion everybody knows about is price caps. It needs scarcity prices. Capacity markets as well, where they exist, suppress energy prices, and that's something that's not discussed very much. Certainly, when you suddenly have a large amount of capacity available in a capacity market, you're going to alter very substantially your LMP market. The day-ahead market itself is another issue. I mean, I am supportive of something like the Australian market, where you have an instantaneous market that people can respond to, where here we have a day-ahead market that doesn't reflect the contingencies, and a real-time market which does reflect contingencies, but it's many times not deep, not liquid, and how do you then create pricing for both of those markets and bring those to retail? The combined effects are that customer demand response is absolutely muted. Price elasticity of demand is muted, and the dispatchability of DR is pretty hard to figure out.

So are all who want to play capable of playing? And can they buy and sell? This is clearly not happening. When participation is limited, the market is incomplete. You have a very inefficient market. Something that is not discussed a lot, but I was happy to see it brought up yesterday, is the whole question of a double-sided market. The theoretical best approach is to use a double auction. That means you've got all possible customers and producers submitting both bid and ask prices. That means a fully liquid market on both sides. That is a very different situation. Clearing prices are then the intersection of those supply and demand curves.

The double auction allows customers to provide demand response at the same market clearing prices as supply. So that's an issue that certainly touches on DR compensation.

Something I don't think a lot of people want to hear about is that, certainly from my view as an economist, LMP prices are not even second best. Customers face a confounding set of price signals for energy and capacity, and a whole set of market distortions. Production and consumption do not directly compete. DR price elasticity is severely limited. And that's an equation that says, you don't have contestability. If you don't have contestability, what do you have? You have a supply-side only market. LMPs are just the short-run version of the longer market.

So let's look at this crude curve on deferred electricity costs for a minute. There's a set of curves here, and it suggests that there's a whole series of deferred costs. We can start from the bottom. Line losses, O&M (and that's fixed and variable O&M), fuel distribution, transmission, and generation. How do you get your price signals to focus so that they can reflect these things, and do they, even in the short run? Then, of course, if they're just working in the short run, they need to somehow be transmitted into probably some version of forward contracts and reflect the longer run. Even the capacity markets that they use are what--three years? So do we have any kind of pricing structure that will do what we think we're supposed to be doing with these markets, create an efficient opportunity to defer this total set of costs? And pardon me, it's not there.

So going on to the retail regulation and rates problem, I'm calling it here a "perennial fog." Or do we have future customer opportunity? And I think customer opportunity is probably a long way off. The fog of retail rate allocation and rate design has already been discussed. Fuel cost adjustment, decoupling, revenue requirements--it's pretty hard to see price signals in the midst of that setting. Should we use equal-percentage-marginal-cost pricing, revenue allocation and rate design? I'm proud to say I helped get that started. But this was in 1985, when we were just talking about how to use marginal costs. And since then, it's been used to some extent, but with a five-tier pricing system such as in California, you don't have anything that translates to real effects on prices and that customers can respond to. Two-part tariffs--again, a great idea. I just don't see that they're working. I don't see that they're going to work easily. Right now, my suggestion is, use periodic customer incentives in lieu of retail rates for dispatchable DR, and that in essence decouples from reliance on retail rates.

I was previously working with Converge. Certainly Speaker 2's model with ENERNOC is many times to make sure that you got customers who respond to some simple annual incentive mechanism. And if you can't signal dispatachability as well, I don't think it's going to work. So how do you get the most high priced, the most important premium set of services to be available in a price response or an automated response approach? I wish I were more positive on this.

Further regulation market rates, this is not indirect in talking about the DR compensation situation. But here I'm going to talk about the case of generator choice in the wholesale markets. Try to follow me here. Theory says, bid incremental costs, and that's an efficient market. Practice is probably for a thermal generator, calculate the "spark spread" option value, and if you're "in the money," you execute in one of two ways. You either generate the power and burn the gas, or buy the power and sell the gas.

So if that's the basic fact pattern, what are the rate implications of this practice? The choice to locally generate and burn the gas contributes very differently to the margin, both on the electric and gas side, or the choice to buy non-local power and sell gas, that changes the contribution picture entirely. I don't see that differently than what people are arguing about with regard to demand response. The lost margin is very significant here. I don't think we want to regulate this area. You don't want to extend regulation into this area. You don't want to regulate behind the meter. So to further regulate wholesale market rates in this regard, I think would be inappropriate, and it's not advised. Similarly on the demand side, it's not advised.

So here's a summary of those last seven slides. Workable competition between generators and customers does not exist. Major market distortions need to be removed. All who are willing to play cannot. Markets are suboptimal and inefficient. A double auction is needed to allow all to play. LMPs are second best. Contestability is absent. Deferred electric rates are not reflected. There's a perennial fog in retail regulation and rates. So we need periodic customer incentives. I see this as market failure. The demand side is muted. It's not captured or monetized. So I'm waiting for real market reform, and certainly I'm pleased that the FERC is trying to work on this. The whole idea that we can get states to be coordinated with this is a fantastic idea, but my conclusion right now is, not with this market. Thank you.

Question: This is really a question for Speaker 2, but I only could articulate it having seen Speaker 3's presentation. So I'll ask it to both of you. To what extent are Speaker 2's needs completely satisfied by having a double auction? It seems to me that what he really should be after--maybe not what commercially he'd prefer, but what from a policy perspective he should be after--is a double side auction. And I want to know whether Speaker 3 thinks that would fix his problem, and if Speaker 2 would think this would fix his problems?

Speaker 3: I think what Speaker 2 gets is the customer's direct response. The double sided auction has to present some version of a combined rate, though, and that's the difficult part. Either you need double auctions for the whole series of services--basically resource adequacy operating reserve, emergency capacity frequency control--all of those, and instructed energy. And if you have double auctions for each of those, then you're obviously making sure that customers are involved. I think you need agents, probably, to represent customers. And by the way, one of the other conclusions here is, as Speaker 1 mentioned, I believe, HAN, the Home Area Network, is an automated way to do that for residential. When you have smart grid that really is automated, absolutely I think you start to overcome these barriers. But it isn't necessarily direct customer participation, except that you program what they need.

Speaker 2: Well, I'll just be very brief. Maybe we can cover it in discussion. It seems to me, at least for those markets with capacity markets, it's really impossible to have that. I mean, price response to demand might be a version of that, so actually it's not impossible. It can be done. We don't have it yet. But we've had this administrative demand curve, and so it seems to me that kind of opportunity is realistically denied, at least in a capacity market where most of, frankly, today demand resources are planned.

Question: But we could trivially reformulate that auction to be a double sided auction. We could trivially reformulate every one of those. I'm not talking about implementation. But you can write down the equations trivially to be double sided auctions. So if we were to do that, would that solve your problem? Maybe it's a bigger question.

Speaker 2: Well, I'm going to say no, but I want to sort of punt and maybe come back to it, because I want to be able to formulate a thoughtful answer.

Question: I have two pretty easy ones for Speaker 3. Just clarification for me on "double auction." That means the customers and the producers both bid in, and then you match it up in the demand curve?

Speaker 3: Right. And they both provide both bid and ask, which is —-

Question: Both.

Speaker 3: Both sides, for both supply and demand.

Question: And is that done anywhere?

Speaker 3: Not in electric markets, not per se.

Question: It's done in other types of markets?

Speaker 3: Yes.

Question: Like?

Speaker 3: Gold bullion, a whole set of things.

Question: OK. And the second one's real easy for you. What is a two-part tariff?

Speaker 3: Basically a fixed-variable tariff, and it's the standard rate design for many, well, a series of industrial customers use this.

Question: Speaker 3, a couple of times, when you were referring to ancillary services, you said that the cost of socialization of ancillary services was "huge." Do you have any estimate of that?

Speaker 3: If you're asking the question, I should be worried. What's huge? You're going to tell me. I think I'll tell you that what you would ask--ancillary services are not a big part of the cost of service, but they're certainly a big part of demand response capability.

Question: Another time you used the term "very inefficient." Do you have any idea what the order of magnitude of "very inefficient" is relative to the market? I mean, I realize that these inefficiencies and socializations exist all over the place, but I'm not sure how huge they are.

Speaker 3: Well, if I could have the database that my esteemed colleague Hung Po Chao has to calculate bid cost markup, for example, then I could tell you that that's a minimum, and that's only the supply-side inefficiency that you've lost, because the demand side would mitigate that, I think, almost entirely.

Question: And when you say that you don't have demand elasticity, are you referring to the fact that they can't bid? Or that demand is elastic, and we just don't know it?

Speaker 3: Both.

Question: So you actually believe that you get huge demand response to small changes in price?

Speaker 3: Wait a minute. Can you restate that?

Question: That's the definition of being elastic.

Speaker 3: You get significant changes in demand from people understanding their options and their price--a composite price. Nobody sees a composite price. Nobody sees it. All they see in an LMP is just the energy price. Do you ever see a scarcity price? Do you ever see a combined scarcity capacity price?

Question: All I'm saying is the conventional wisdom, as I understand it, is that the demand is very inelastic, even if it could bid into the market. And I think you're saying it's not. And I've never seen any evidence of that.

Speaker 3: In the top 500 hours of the year, I'll just draw that line, I think there's a lot of elasticity. In the other 8,760 hours of the year, there may not be. But that top 500 is so significant, that's where DR would play. That's where you would find locational benefits. That's where you're going to locate and use energy efficiency demand response, DG and storage, and you're going to change the load factor from a current 50% in the US to probably something much greater.

Question: OK, since Speaker 3 mentioned the composite option, let me clarify what I mean by that. Also, I have something that I want to confirm with Speaker 2 with regard to demand response.

I don't want to take too much time, because all the things I have to say are just published in the article here. If you are interested in the technical details, you can go to that article. I can spend two hours here otherwise.

What I mean by "composite option" here, I think there's an important specific point no one has mentioned here. And in the debate, I think there has been very little mention of it. So the point about the composite option here is that the starting point is that customers, every one of us today has an open option to consume electricity. We consume any amount. That's an option, a quantity option, and we have fixed price. So it's like going to a fixed price unlimited buffet, and no one tells you when to stop, only you when you are satisfied, then you stop.

Now, I think that this brings up the issue of customer baseline in demand response. That's what I'm going to get to, Speaker 2, because if you want to sell what you don't use, now you have to deal with this option that you have.

In other words, what I argue in the article is that there are two steps, in order to handle this, to sell demand response. The number one step is that you have to sell your right of consuming beyond a certain level. That's customer baseline. The customer has to choose a customer baseline, and you can get paid for that. We need to have a bank mechanism for customers to give away that option. And then if the customer wants to establish that customer baseline. Then you have a basis, contractual basis, that's important. The customer agreed. Only the customer can empower that customer baseline. No one else can. You cannot use a statistical method to calculate anything and then say that that has any contractual binding power. That's my view. What you sell is to give a load-serving entity or whoever that is providing that option the right to take away that amount that you don't use when some certain condition is met. So the customer gets paid for that.

I think that these two steps in sequence are important. In my view, the customer baseline needs to get the customer involved, engaged, or agreed. Otherwise, if that issue is swept aside, I think that if you read Alfred Kahn's first footnote, that this issue may actually dominate the entire issue of demand response compensation as I read it. I don't know, Speaker 2, whether you agree with my sort of clarification of the customer baseline issue.

Speaker 2: You're, are you suggesting that the customer essentially should buy his baseline and then resolve the non-consumption?

Question: I think that that's one way of doing it. Let me put it another way. Certainly we can sell anything that we have bought. We establish tradable property rights when we buy something. So what I think here is important is that the option that I'm talking about is based on the obligation to serve. It's a regulatory right. It's endorsed by the regulatory agency. It's not a tradable property right. You cannot sell your obligation to serve. That's open.

So my point here is the following, is that you have to establish a legitimate baseline. You said, would you have to buy the customer baseline? I said, yes. And then how do you buy it? Buying through the market is one way to establish that. Now for example, let me just take emission trading. That baseline is established by the regulator with a rule, with an allocation. You can get it for free, whatever. You have that right. That can be traded. There has to be a quantity that is authorized through a legitimate process. I say buying is certainly a legitimate process.

Speaker 2: Well, that's a reasonable position that some hold, but that approach starts from the premise that demand response is merely the non-use of pre-purchased energy or capacity, and that it's a commodity. And as I clarified in my remarks, that dynamic capability is a *service*. The dynamic reduction capability is a service that demand responders participating as a supply resource are providing to the market. So the baseline mechanisms, I mean, all of them have to be imperfect, because it's basically a but-for determination of what would demand have been had they consumed.

They're getting more rigorous, and people are trying to improve them. But the best we have them today is some effort of seeding a baseline to figure out what customers under that open option that they had today, what they're actually consuming in near real time, and then looking at the load drop from that baseline. But that's a very different thing than simply saying that I'm not using a commodity. Again, it's the distinction that demand response is a *service* affecting wholesale rates, rather than a commodity.

Question: I can live with that, probably. We can talk more about that. We can agree to disagree.

Speaker 4.

I come to a bit of a different conclusion than some here, but I will say I'm a lawyer. I'm not an economist or an engineer by background. But it doesn't stop me from having opinions and having people ask me for those opinions. So I might as well give them.

I think the theoretical right answer in general that I aim towards is that if you, the customer, don't want to use power, then don't buy it. And we'll try to get you the appropriate economic reward for not buying it. And with that, I'll get into what I'm supposed to be speaking about.

The focus is dynamic pricing in retail tariffs. I agree--and some consumer advocates disagree--but I agree that dynamic pricing in retail tariffs would be a very beneficial thing in a lot of ways, including even passing through LMPs, potentially. But it also creates some difficult and interesting issues. Those issues were framed well in the questions presented in the Agenda, so I figured I might as well seek to answer those questions in the order that they were presented, and that's how my slides are organized.

So the first question presented was, if the demand side bids in the wholesale FERC energy market receive nodal prices, which is what FERC seems to be heading toward, is that problematic if there's no coordination with the retail tariffs? And I think it is a big problem. And I think it is a big problem largely because I am in the same camp with Professor Hogan on these issues. I was hoping he would be here to hear that. But maybe someone can pass that along. (But we still disagree on whether we should have long-term contracts for power plant capacity.) But I agree with him on this--I think it would a mistake to pay full LMP to demand resources, because I think it's an overpayment, especially as the retail tariffs become more dynamic. If the full economic value of demand response is being paid through the retail tariff, then receiving full LMP at the FERC level, again--at the wholesale level, becomes an overpayment, and in the extreme degree, a double payment.

And why is that a problem? If you overpay DR, then you may get too much of it in your capacity resource mix. So if the overall capacity and energy payments to DR get too high, then your percentage of capacity resources becomes too heavily staked to DR and not enough to power plant capacity. So our impulse is to make sure that we have enough power plant capacity. That's why we have been aggressively building capacity in Connecticut, as well as transmission lines. Power plants provide Connecticut with a product that Connecticut is quite fond of. So that is the approach we've taken. And we are an odd restructured state in that we have integrated resource planning again, and so we have to deal with these issues in our IRP processes.

Now, I will say that DR certainly has a role. It's a welcome role. And if it was simply an energy play, fine--and I won't pretend that the markets value it perfectly today because of externalities, like the environmental externality, and I'm not sure the transmission congestion is fully dealt with appropriately in the markets, and there are others that have been raised by the panelists.

The next question that was presented was, if retail tariffs are flat, how can we or could we motivate customers to engage in demand response? I bring up inclining block rates. A lot of people are critical of inclining block rates, or they don't think that they'll really achieve much in the way of demand response. I'm not as sure of that, especially at the residential level, if it encourages people to get more efficient with their air conditioning usage, and I'll also note that inclining block rates come essentially free, from an infrastructure perspective. But I won't pretend that it would be nearly as robust as full LMP in the retail rates.

You could have demand charges, including for residential customers, perhaps with only a slight incremental cost to the meter.

And of course, we are looking towards smart appliances. Even if you had flat retail tariffs, you could have smart appliances and programs like we've had in New England to provide capacity payments to DR.

How could retail customers receive the appropriate compensation for DR, which is the next question presented? I think it would require advanced metering. And what would the benefits of that be to customers, as I see them? You eliminate the cost in your standard service or basic service rates of the hedge, of the aggregators' and the bidders' projections of what the energy price and the congestion is going to be. So that can be substantial. I've been a bit disappointed with Connecticut's standard service rates of late, so eliminating that hedge or that insurance is particularly attractive. I also think doing so would be consistent with cost causation principles. And it would assist the low income customers with paying their bills, since they tend to be lower air conditioner users, especially in a northern state like Connecticut. And lastly, it would reduce or eliminate this difficulty of having to treat DR as a resource, if we move towards full LMP in the retail tariff.

One of the difficulties, though, in trying to use LMP in the retail tariff, of course, is that you do need smart meters, and the only perhaps unique thing that I have to say today is that I am concerned that there have been lots of pilots that have shown that customers will respond to dynamic pricing tariffs. And more robustly than some naysayers might have projected, including low income customers, by the way. In Washington and Connecticut, low income customers, some of them, I understand (I don't know that you want people doing this), but they shut their power off entirely and went to the movies to cool themselves off. So people will respond perhaps more than anticipated.

But what I anticipate is that if we do dynamic default service, that the retailers will come in, in retail choice states like Connecticut, and turn around and offer flat rates. And I expect that to be a very potent ad campaign by the retailers, and that will be their only option for continuing in the business. They can show things like people having to set their alarm for 2 o'clock in the morning in order to do their laundry, or having an icy tub in their living room, or these sorts of things. So I think it will be a very effective campaign, and so I'm concerned that if your pilot is being done, as it must be, outside the context of this massive ad campaign that I project would occur by the retailers, then are you getting an accurate sense of how robust the adoption of dynamic pricing will be? And so if you are relying in your cost benefit analysis on significant adoption by customers of dynamic pricing, if you haven't thought that through--and it's going to be very difficult to try to quantify that issue--but if you don't, your guesses and projections of how attractive dynamic pricing may turn out to be could be far off. So, for example, you may expect that you're going to have transmission distribution benefits, or you're going to avoid a peak, and you put all these things into your cost/benefit analysis, and if dynamic pricing turns out to be not nearly as attractive as you expect, then the benefit side may not occur.

I don't want to just throw out a massive potential problem, as I see it, without offering a solution. So I think one possible solution is to go ahead and require that basic service or standard service rates, and the rates of retailers, have a certain level of dynamism. For example, you could require that retailers and the standard service offer both include critical peak pricing. And so whatever else you do with your rates, you have to have critical peak pricing for hot days in the summer. And most consumer advocates are very reluctant to do anything mandatory on default service being dynamic, but perhaps we can solve that politically, or have some customers that you just leave aside, customers who have oxygen tanks or something--we have some opt-out program for them.

One question is, how do we get a solution to these issues so that we can get that more dynamic default service? And I'm wondering if perhaps electric vehicles will force a solution. When I say electric vehicles will force a solution, perhaps the question is, will oil prices force a solution? And so, will a federal push for electric vehicles, because of oil prices, create a felt need to solve this problem on a national basis and make sure that we get dynamic rates at the retail level? Problems don't tend to get solved unless there's a felt need, politically, for there to be a solution.

The next slide just highlights some of the additional difficulties that, maybe not in California, but on a national level we're going to see in trying to get smart meters in, and they're well known.

And the next question presented has to do with the difficulties of LMPs in retail rates, in terms of too much information or too little timely information. And so a lot of the pilots, as you probably know, explore different ways of doing this. I think a lot of the pilots have indicated that many of the benefits can be accomplished through critical peak pricing, but there's a very significant gap between your critical peak price and your ordinary price. So that may be the right way to balance, or maybe the training wheels towards a fully dynamic retail service tariff would be to have critical peak pricing as at least the way station if not the long term landing spot.

Peak time rebates is something else that is explored in the pilots, where you have just no losers, and if you respond to the price signal, then you get money. But I think the studies have tended to show that that does not lead to optimal results. It doesn't lead to the same robust level of results as having both sticks and carrots.

Another question presented in the document is how might FERC collaborate with PUCs to assure coordinated price signals? I think they will have to meet--and I should have added retailers on that list--to develop best practices. And I think potentially the carrot that could be offered to the states would be reduced installed capacity requirements. If FERC becomes confident that your state is moving toward dynamic retail tariffs, perhaps they could ramp down from 115 to 112 the installed capacity requirement for your state.

And the last question presented, will state energy efficiency programs be enhanced by fully coordinating the retail and wholesale rates--I think they certainly would be. Especially for residential, a lot of the activities that you would do at peak times, you will also do as part of an energy efficiency program. So I think there's a dual benefit there. Anything that reduces usage for residential at all times often reduces their usage at peak times. And that would have the side benefit of helping to address one of my favorite issues, which is trying to reduce the incentives that we provide to customers to save themselves money by participating in energy efficiency programs. I think that a more dynamic retail service tariff, because it would have this benefit, would help us achieve that.

Question: I just had a quick question. You mentioned that the Public Utilities Commission could require the retail providers and the utilities both to implement dynamic pricing. I was wondering, in your jurisdiction, does the Public Utilities Commission have any jurisdiction over the retail providers' pricing mechanisms?

Speaker 4: I think it would require legal changes.

Question: Just real quickly. I know you were clear you were speaking for yourself, not your office.

Speaker 4: Right.

Question: Were similar comments about payments, overpayment made in the DR NOPR by the Office of Consumer Counsel in Connecticut?

Speaker 4: No, Mary Healey is the president of NASUCA, and NASUCA took a different stance, as you probably know or may know.

Question: That's why I was curious about it.

Speaker 4: I made this argument internally, both in Connecticut and to NASUCA, and I didn't win. But it doesn't mean I can't make it here.

Question: So my question is that you talked about mandatory dynamic pricing.

Speaker 4: Yes.

Question: So you're not talking about opt in or opt out. Would you think that opt out would benefit the customers that do not want to part of the dynamic pricing?

Speaker 4: I think with the right level of education, and given that we're going to be moving, I think, in the next decade as a nation to more advanced metering, I think people are going to have to come to accept opt out. With the right level of education, hopefully it will reach the groups for whom that will be the most deleterious and the most unfair, because they are on an oxygen tank, or whatever the reason is. So health issues and so forth, and I would encourage my fellow consumer advocates to move in that direction. It's a very difficult issue for consumer advocates.

General Discussion.

Question: I have a question generally for all panel members. Let me just start out by saying that I hope that we all have a consensus here about what the problem is. I think the problem here is that the wholesale and retail markets are disconnected. The consumers don't see or don't have access to the right prices. Evidence: the California electricity crisis. No one can dispute that. A lot of articles have been written about that.

And then what are the barriers to changing this? In my personal view, and it's shared by many, one barrier is the technology—the lack of advanced metering infrastructure, and the other barrier is institutional--the prevalence of these fixed retail rates with unlimited options to purchase power. And that's like an addiction. It's very hard to get rid of.

Now, what can we do about it? I heard from everyone, I think, a diverse array of approaches, talking about how to represent consumers in the wholesale market with greater granularity, on a locational basis, and talking about the customers' different values, and also other dimensions.

As we move to this new market regime, we hope to have a game change. What I will bring up is a question of product differentiation. There is a tremendous sort of iversity among customers. And what we want to accomplish in the competitive market is to provide a level playing field--to provide efficient signals to all participants in the market in a way that can support innovation.

So let me narrow down the product differentiation to an old idea that I've been working on since some time ago, reliability. As we know that today, reliability is a non-excludable product. The system has one level of reliability, largely when as an individual you suffer unreliability or interruption along with your neighbors. You have no way out of it. That's the current system. The question here is, can reliability be differentiated, once we have a smart grid and have smart pricing?

The reason I mention that here is that on the supply side we see the differentiation, although it's incomplete. We have energy product, reserve product, regulation product. You have locational differentiation. There are all kind of different products propagating on the supply side. It's still being developed.

On the demand side, we see that there's a lot of aggregation, but still no differentiation. So what I see here is that in electricity, one of the most important things is to keep the lights on--reliability. If we can in some way differentiate the pricing and the product definition for reliability, that will change the whole system. Eventually probably the ISO's role will be totally different. I wonder whether all of you can comment on that from your perspective. I think this is a good opportunity to hear whether that is a direction that in your view is worth pursuing.

Speaker 1: I'll take a start at this. You talked about the issue of the technology--to be able to meter properly, which is one that we're in the process of overcoming, at least in California--and then the issue of rate making. And ultimately, then, the reliability issue.

A couple of things in response. One, the technology theoretically could also provide an avenue to deal with reliability on a customer-specific basis, but both the rate making and the politics of doing that make it hard to imagine that that's where we're going to go. You could design rates, taking advantage of all this technology, to achieve the kind of economic efficiency that we all might say is most desirable. But the reality is that that the rate-making process is as much associated with equities and other public policies as it is with achieving economic efficiency. Otherwise you can't explain in any way the rate structures that we've got today. So you would need a fundamental rethinking of what we're trying to do with rates at the retail level, and I don't really see that coming any time soon. So those economic efficiencies that may be possible, including reliability, are probably a long way off.

Speaker 3: I really like the question. I think that it's pretty hard to get prices across [to retail consumers], in part because you need to aggregate these pieces. How do you get the day ahead and hour ahead energy prices and the capacity prices to somehow be translated so the customers can respond? I'm seeing the smart grid as the way to do that. And this is energy management systems and some version of ZigBee HAN for the retail side.

But we need, in essence, an aggregator or somebody. My old employer pitched that. They went to educate customers, gave them a three-tiered time of use and a CPP, and then gave them the capability to maybe have smart thermostats. In that case, the customer's like, wow, great. Huge response. It's a double-peaking Florida situation, with tremendous cost effectiveness. But it took going to the customer and offering to set up the thermostat and the system, and the customer actually paid to be on the system. So that was a narrow segment, not necessarily generalizable, but I think that's one model.

And I think that's ultimately what we need, is some agent and/or way to convey that service on the retail side, as well as the technology. So you have to have those two pieces, because otherwise there's no way to in essence compile this very complex set of benefits, and moreover, to product differentiate.

So as others don't know, I'm a huge fan of Hung-Po Chao's and Robert Wilson's paper in 1985 or '86. Priority service pricing is about reliability differentiation. I'm still a huge fan. It is a way to do this. Should we and can't we get customers to do that? Air conditioner cycling is a way to do that with ZigBee HAN, or an energy management system at the commercial/industrial level. You can do exactly that. What are the discretionary loads? What are the nondiscretionary loads?

One other example. Kodak's x-ray film processing facility in Colorado became a client. We went to them, and they said, "This is international x-ray processing. You touch our loads, we're going to kill you." We said, "Wait a minute. What about your discretionary loads?" "Well, show us that you have those." Out of a ten megawatt load, we found five to six megawatts of discretionary loads, hugely cost effective, very, very profitable. They couldn't believe it. They were all happy. We didn't mess with any of their non-discretionary loads. Could those loads be turned off and change their priority in terms of reliability? Absolutely. So I think there's examples across the board to find those customers and to do those things.

Speaker 2: I'll try to be brief, because I know we have lots of questions. But I actually think that there's a huge amount of diversity--product differentiation--in how you harvest demand side resources. And it's more than just on/off, because resources have different capabilities. You can shut motors down only so fast—shutting down too fast can do damage to the motor. You have to think about how you design your production line and where you can take energy off line and where you can build inventory for the next piece of the process. You need to think about precooling, which is more than just a one-off. That's a conscious decision before hand, that it makes sense for me to precool my building or precool my cold storage facility to weather out a high priced period. It seems to me there's incredible innovation and creativity that is going into harvesting that demand resource, and that's where product differentiation is occurring.

Moderator: I'll just make one brief comment, and that is that I do agree that with smart grid, at least the resource adequacy component of reliability can be made into a private good. We already see this in parts of the EU, where people buy a demand subscription service, and I think the fact that we're not there today is in large part not a question of policy as much as it is an historical artifact of our ability to measure with past metering technologies. But that's my own view, and others may have different views.

Question: Thank you. My clarifying question was going to be to Speaker 3. You said a number of times that LMPs are second best, and I wasn't sure if you meant that as a dispatch signal for demand resources, or as a payment mechanism, and what you thought was preferable.

But now that this is a discussion question, I'd like to expand that a little bit. The fundamental issue here is that we have a construct which we think is economically efficient based on LMPs and dispatch. I'm on board there. In fact, in contrast to some of my colleagues, I think that paying full LMP for energy is problematic. Perhaps it was all my years with Richard Tabors. However, there are other attributes associated with demand resources and demand response that should be recognized, not just the fact that there are market barriers, but the fact that we think there are numerous social benefits that I don't have to enumerate here.

And I wonder what folks would think about another market that recognized those, similar to the REC market for renewables. If a state determines that a good level of demand response resources would be, say, 10% of peak load, why not have a market for that service, hopefully having learned our lesson from the poignantly named FCM market? (We would not call this DRECs.)

Speaker 3: I am concerned about anything that isn't pulled tightly to the supply market. In other words, comparability and a combined market is where I think the efficiencies are. To peel off another dimension of the clean energy market, such as RECS, and RPS standards, to me, raises worries about subsidies, worries about special treatment, worries about politics. I've seen the regulatory process. I know how that sausage is made. I don't like it. I want to see market discipline tightly tied to whatever happens in energy efficiency. And I'm a huge fan of markets. I want markets to work. So I think that the combined effects of making sure those are disciplining each other, that's the way…because the other thing is, I'm worried about the long term sustainability of just the supply side market. I don't think it's sustainable, unless you have a big demand-side play in it. So it needs to be part of it. I hope that's responsive.

Speaker 4: Can I say something? I'm intrigued by that thought. As I mentioned, the environmental externality, for example, is not properly accounted for in today's markets. Today's markets have that imperfection, as well as not valuing sufficiently the reliability benefits of DR. So if you're trying to put a little thumb on the scale to make up for that market inefficiency, I'm interested. But maybe that prevents an ultimate resolution. Right? If you do a band aid, does it make you not heal the actual wound? I don't know. I agree that we should decide about how much DR that we can have for peak load and just aim for it. And that can change over time, as experience grows. So I like the theme of what you're saying, and the details, I think, we'd have to work out.

Speaker 1: Yes, I think what would be better, rather than trying to reflect environmental externalities and what we value DR for, is if we were already internalizing those in the cost of electricity, and then to extent you're avoiding the consumption through demand response, then you're automatically avoiding the cost that's built into the rate in the first place. This goes back to what I said earlier about rate design not reflecting costs very well, because for example, in demand response, in many instances you may not be avoiding a lot of the fixed costs that are already built into the rate. You're probably not avoiding some of the distribution costs associated with your actions (depending on the specific demand response use and all that, because there are some cases where you are), but you're avoiding the rate component associated with it, because we don't have a rate that's split up, for instance, between fixed and variable costs appropriately. So I think it's hard. It can be done, but you have to think about it carefully, and the tendency tends to be to throw in a lot of the benefits of what's avoided without actually thinking carefully about what really is avoided when we don't consume. There are some things that should be captured and probably are not, but there are also some things that are being captured that probably shouldn't be.

Question: So I wish I lived in Southern California, where Speaker 1 lives, sometimes, not only because the weather is often better down here, but also because where I live in Northern California, there's been significant backlash against smart meters. I think a lot of that has to do with the way that the rollout there was managed by Pacific Gas and Electric, versus how it was handled by Southern California Edison or San Diego Gas and Electric.

The first wave of complaints was about how the meters don't work. They're "cheater meters." They charge you for more usage than you really had. The latest wave is that they're unsafe, and they cause everything from brain cancer to the Black Death.

And one reason I was really happy to be here yesterday at this meeting, instead of at the CPUC's business meeting, was that there were two hours of public speakers preceding the business at that meeting, talking about all of the maladies that they had experienced as a result of their smart meters.

But here are a couple of points to take away from that. The first thing is that all this controversy about the meters themselves that we're experiencing, and it's popping up in other places, is the dress rehearsal for the real conflagration, which is going to erupt around the smart rates, for lack of a better word, for time of use, CPP, real time pricing, and it's a real wakeup call for regulators to really think about the transition and how to get people bought into it, because it's a real paradigm shift--essentially the emergence of cost effective technology that makes it possible to price electricity at the retail level in a way that actually reflects how costs are incurred in the production of electricity. And that takes me back to an interesting insight that the Commission got when it did a study on the causes of the huge bills that some people experienced, particularly around Bakersfield and the San Joaquin Valley, supposedly, and in many cases actually, after they got a smart meter. It turned out that the smart meters installation that PG&E did, unfortunately during the summer, coincided both with a rate increase that made their tier system even steeper than the very steep structure that they already had, and there was a heat wave. And the reason that I think this is particularly ironic is because one of the most vocal critics of smart meters in Northern California has taken to referring to critical peak pricing as "heat wave pricing." But this just shows how unfair the tier system can be, and that it's "heat wave pricing," too.

So the first point, I think, that is obvious to this group, but really needs to be more effectively communicated, is simply that tiers don't make the connection between rates and how the costs are incurred, and that's the direction that we want to go. That connection can be strengthened and be made apparent to the customers with new and better technology, not just the meters, but Speaker 3 talked about the HANs. An imperative for regulators is that in order to both reap the significantly greater degree of demand response that I do believe exists (and particularly in those top 500 hours) people have to have the means to respond to it probably without thinking about it, or without thinking about it in real time. And I think that in California, one of the biggest problems that we have with the way that we did our rollout is that we did not plan for that. The rollout was just done on the basis of the idea that the meters themselves are going to be so valuable that if you build them, if you install them, the benefits will come.

And I think that there really has to be a holistic approach, and that we also need appropriate choice. Our architecture is the opt-in model, but probably the opt-out model is the appropriate choice architecture.

So I wanted to respond to a point that Speaker 4 made about how he thought that if you go to mandatory or opt-out critical peak pricing, then you're going to see retail providers jump in with an all-you-can-eat rate. I would argue that no, the utilities should be requiring the all-you-can-eat rate, because there's some people who like the all-you-can-eat rate. But the difference is that it has to reflect the option value or the insurance value that you get from being able to have the all-you-can-eat rate. There has to be essentially extra capacity reservations for those customers. It's just like the old days in the telephone industry, where you could have fixed rate, flat rate, or measured rate, depending on how much you wanted to manage things.

So sort of building off these points, one question I'll ask the panelists is, do you think that in the transition to rates that at least more closely approximate real-time rates, is the inclining block approach obsolete and needs to be replaced?

And then finally, just sort of one last thought. How can we move away from the language of carrots and sticks? Because those I think reflect a notion that there's some sort of inherent fairness in the baseline today, and the idea that mandatory CPP is about sticks, while peak time rebates are about carrots… Well, nobody likes to be given carrots and then sticks. So my question is, what is the benefit of that verbiage? And is it time to do away with inclining block pricing? I mean, what the tiered rates do (and this was very evident, again, in a case in California) is they deposit baskets of carrots on the doorsteps of coastal residents.

Speaker 1: I can give you a short answer to one part of the question. Personally I do believe it's time to get rid of the tiered rate structure. The problems that it causes are certainly a lot greater than I don't know what perceived benefits there may be associated with it.

Speaker 2: This may be a bit controversial, but I do think that certainly anything like mandating dynamic pricing, is going to get a customer backlash that frankly is… It is a totalitarian concept to me. We should not be mandating. I mean, you can have an opt in/opt out discussion, that's one thing. But to me, after having 100 years of regulatory inertia behind flat rates, to take that away and put customers on a completely new regime is something that customers will not stand for.

The controversial part is that actually I would prefer to let the invisible hand of the market decide what customers want and what their preferences are. In my home state of Maryland, large customers, larger than 300 Kw, are on a default hourly priced service rate. That's the default rate. So 95+% of customers have switched from that rate, which is an amazing success statistic for the wonders of retail competition. What does it tell you about customers' preference for dynamic pricing? There's a big story there.

I think customers should have those options, and I think we are in trouble if the assumption for the cost effectiveness for smart meters is that they will actually go there. If they don't go there, I think we assume that they are rational economic actors making decisions to accept this kind of pricing or not. If they do accept it, great. If they don't accept it, great. I'm all about, as I've heard talked about in smart grid circles, "democratizing the grid" and giving customers the choice of their preference at the end.

Speaker 1: I have to have some rebuttal, I guess, to that. You may be right about the political reaction. The customers just may find it unacceptable to change paradigms, but it's hard to accept that it is totalitarian to actually ask them to pay for what they're causing in terms of costs to the system, as opposed to keeping the subsidies that are in place today simply because that's what we've done in the past. We may choose to go there, because nobody wants to deal with the adverse customer reaction, but it's certainly not unfair to ask people to pay for what they use, based on the cost of using it, which is where we would want to go.

Now, to the extent you allow it to be on a voluntary basis, you give the appearance of taking away the losers and only allowing winners. But you're really just exacerbating those subsidies for those that are choosing to keep their existing flat rate subsidies. If you require them to pay for that by incurring the hedge costs associated with maintaining that subsidy, that's a different paradigm, and then they're choosing what risks they want to take associated with their use. But at least they're paying for what they're causing on the system.

Speaker 3: I will surprise everybody and agree with the questioner, Speaker 1, and Speaker 2 without argument. [LAUGHTER]

Moderator: Well, I'm going to jump in just a moment here and say a couple of things. One is that we know from behavioral economics that defaults matter, and so what we set as the default will have a very important impact on where this market goes. We know from what we have seen in a number of the pilots, where we have incorporated at least a dynamic component within rates, customers generally like it. There is overwhelming positive response, and they view it as empowering. So I'm not so pessimistic about what the response will be. I do think that it will be valuable to distinguish as we do this, between what it really costs you for service, and what I would view as an insurance product or a hedge product, and allow the competition to occur around how much hedge people are willing to buy, but keep the distinction in place, and that moves us away from the carrot and stick question.

Speaker 2: We don't disagree that the costs should be allocated. So if you want flat rate, you've got to pay the full cost of that. We don't disagree. I used an analogy during the break that it's about like the US policy to move to the metric system that I recall from when I was growing up. We might have been better off if we did it. At the end of the day, the customers, the citizenry at large, elected not to do it. Now, that might be what we're embarking on with smart rates, I don't think we know. We don't know yet whether customers will really value in the marketplace this ability to have a stock ticker that will tell them when it is time to consume and not consume, and whether consumers will really prefer to buy refrigerators that would do these things. It may well be. I certainly want that platform to be able to allow that innovation to occur. But I don't necessarily think that success or failure rides on consumer preferences for smart technology. I just want to give them options.

Speaker 3: I was just going to say, I think automation's going to be required. I don't think you want customers to be in the mode of responding very much. There is a small group that will. We've seen some of those experiments with ComEd and other places. So I think it's going to be about automation and enabling the customer to make a series of choices that are pretty much programmed choices.

Speaker 4: One sentence in response. Excellent points and questions. If the default is flat in Connecticut or in a lot of the states in the East, I don't know that we will be able to project that a smart meter infrastructure program will meet that benefit-to-cost test. So that's why I've sort of assumed that the default would be something other than flat. I assume that that had to be part of the decision allowing the smart meter implementation.

Question: I think this is a clarifying question for Speaker 3, but it might turn into a bit of a debate. I'm confused by (I think it's slide seven) your fifth point on "Deferred electricity costs--What connection to markets or rates?"

Several people have invoked Alfred Kahn, who's also one of my personal heroes, and I remember this debate about whether rates should be based on short-term or long-term marginal costs back in the day, back in the late '70s and early '80s. In his *Economics of Regulation*, he addresses this discussion in some detail, and he said, prices should be established for the time period over which they're going to apply. So if you're doing a pro forma rate case for the next year, you focus on costs for the next year. They should match. And I thought that was brilliant. I mean, that was grounded in common sense, and you could make it operational. And so when I saw this graph, which is going out 20 years and talking about deferring something out 20 years… I guess I missed what point it is that you were trying to make. Were you talking about reflecting rates and doing a 20 year projection? What were you thinking, Speaker 3? [LAUGHTER]

Speaker 3: What was I thinking? Thank you for the great question. I'm really saying that there isn't any long-term thinking in rate design or customer decisions, and how can you get there? And I think you should try to get there. To the extent there's long-term contracts, for example, certainly for Converge, they want a ten or 12 year contract with the customer. And then they're going to pay them a significantly greater incentive for doing demand response. And the customer doesn't really care, as long as they think they're going to be there for that long. And there's customer churn, so that's part of the average. Not everybody stays for 12 years. Those things can be woven into the deal. And in this case, it's a bilateral pay for performance contract, a hell of a deal for consumers, as long as you think that deferring that much capacity is a good thing. So everything here applies.

And by the way, I read Alfred Kahn. I did rate design a lot, and we were always to look for long run marginal cost in EPMC, and that is the policy of California, as far as I know. So it's long run marginal cost, not short run.

Question: Well, it was that thinking that led to deregulation in the first place, because our projections were going like this, and the market was going like that. And it just diverged all through the '80s and into the '90s.

Speaker 3: There's a lot of uncertainty as you go out, obviously, which is a big issue.

Question: I was struck a bit by the conversation having to do with whether the market we have, which includes LMPs, would not be really the most effective platform. I think, Speaker 3, you were more eloquent about that aspect of it. I was going to challenge that, but I wanted also to hear more about where you thought we should go, as opposed to the fact that we have a problem. But I think the LMP market has been fairly effective in dealing with this issue of an efficient use of transmission and then the cooptimized dispatch. Right? And then the pricing is just an overlay on top of that. And so where do we go with that, if you think this is not the right platform for dealing with the retail side? And do you have something specific in mind?

Speaker 3: Well, I think the theoretic best that Alfred Kahn and a whole set of other—Kleindorfer, or whoever you want to talk about--would emphasize is that it's the combined effect. I think Hung-Po Chao would say the same thing, that it's not just the LMP, but it's the capacity and the other things that you are going to change. If demand response in a long-term contract that Converge or EnerNOC has can be on a flexible trigger for Southern California Edison, and it can be used for energy, instructed energy, the most expensive energy, resource adequacy, operating reserve, and even frequency control, emergency capacity, and in their case, distribution load management, then something has to happen to aggregate that set of benefits, and it's way beyond LMP.

As my curve suggested, by the time you get to the cumulative energy part of the equation for the long term, it's dwarfed by the long-term capital deferral. So are we really taking about long-term capital deferral as a benefit for DR? And if we are, and you can get it, great. If you can only get the short run, then it's an LMP signal. So I think it's that's simple.

Question: I think I understand the concerns you have, I guess. But I guess I don't see where you're trying to say the solution lies.

Speaker 3: So if you automate the response under ZigBee HAN, and in essence you think that's long-term equipment and capability, you would in essence try to give the customer a long-term signal, and they would respond, hopefully, and be able to defer the investment that they made for being able to defer those long-term capital costs. So I think there's not one answer. The LMP may work very well for industrial steel mills. I mean, certainly Converge plays, and I think EnerNOC does, in PJM's energy market with industrials. But they make short-term decisions, and they don't want to be locked into anything long term.

Question: So I understand that you want to bring the customer-related optionality into the optimization of the market. Right? So perhaps instead of just cooptimizing the dispatch of power plants, you cooptimize dispatch of the customer element <u>and</u> the power plants. However, you're still trying to make the customer make the decisions and have a price signal that precedes that optimization handed off to the customer. So I just don't see that.

Speaker 3: Converge would bundle that into an incentive for the customer. It's a single incentive. Then they worry about, in essence, providing the services, or giving those services to the utility, and the utility then dispatches it as it needs to, to in essence take advantage of that optionality.

So my only solution right now, in the short term, is to use those customer incentives, which may be short or long term. But they're an incentive package, so that the price, per se, is bundled in. Do you want $515, $500, $1,000 a month for giving me X megawatts? And how many hours? So it's a matrix of hours, price, and duration that you sell to the customer.

Question: I'm going to come at this from the perspective of the geeky engineer that I am, and try to talk a little bit about enabling the technology and innovation, which is, I think, something we thought about way back when we started LMP and restructuring and all these things.

I was doing a little quick math here, and we've been working 17 years on nodal pricing. And so it depresses me that maybe it's going to take us 17 years to figure this out. But I think there are some basic fundamentals that come to mind. We're really trying to push intelligence to the edge of the grid, and in some cases, from a utility's perspective, we may be pushing it through the edge of the grid as we go into the customer sites.

So in California, we have UC San Diego as our technology demonstration, and they're a 43 megawatt customer. So when I look at the 23,000 megawatt peak load of Southern California Edison, which is about the size of New England ISO or New York ISO, when I'm looking for my customer needle in the haystack, it helps me to have smaller haystacks, so I can find those customers that I can actually make a difference for with my technology.

I want to separate what FERC is doing on the granularity issue from the decisions we make around retail rate making. I think one sets the enabling conditions for the other, but they're not necessarily an if-then-therefore continuum. So hopefully we can hold that aside and make the decisions in a logical fashion.

As we're looking at this, we're still trying to answer the question we were asking 17 years ago. How do I deploy resources in the right place, at the right time, with the right response? And that's really the nugget of the question that we're trying to answer. And so I'm hoping as we look at this, we can maybe say some customers can respond better than others. And it isn't, on average, residential customers that we want to target first. It might be a few strategic, very large, very meaningful customers.

But as I look at the characteristics across--and let me just pick on California, because I'm here now--we have once-through cooling that will have very, very large impacts along the coast. We have renewable variable generation out in the desert, and that will have a very different impact in that part of our service territories. And we need to solve the problem at both edges.

I also see a future where deploying infrastructure quickly may become a challenge for utilities. If you have six families with Teslas hooking into the same feeder, that's a problem that in the long run you'd like to have, because it's eventually rate based, right, and nice assets. But in the short run, it's a very, very thorny problem, and when we're all trying to keep customer satisfaction scores up, it really would help to have some sort of… and instead of thinking about it as a switch, we're starting to think about it as a throttle. And so that's what the new enabling technology does, is not say, oh, let's not make it on/off. Let's make it forward a little, back a little, up a little, down a little.

And so I just want to speak to how important it is, first, for the granularity, for small technology providers like us to be able to partner with very, very large and sophisticated energy companies, and then also how important it is to give some transparency to the true needs. So it's the energy. It's the capacity--and I realize we don't have a centralized market in California, but we do have a quantity, and in some effect, we have a price. And the more we can get those sorts of things exposed, the more I think we can enable technology so that we aren't kind of sitting there with the washer and the dryer at 2:00 in the morning. I don't think that's our scenario of choice across the board.

What we want to do is create moments and opportunities for the enabling technology. So I just want to make a plea for partnership, realizing that we might be in this boat for about 20 years together. And also to make a plea, as we're thinking through this, to get back to the nugget, which is, what does the grid need, and how do we enable demand side to participate as a resource in a way that's meaningful to the physics?

Speaker 1: I guess when looking at the LMP issue, I still think we should look at the priority and the timing with which we should be doing things. To the extent we can take advantage of technology to pass prices through and respond more effectively to them, what element of that is going to be important? And for that I think things like the timing of when the system needs resources and when it doesn't [is something we need to consider]. The price over time is something that varies a lot today, so if we have the technology we can take advantage of it. When it comes to geography, the variation is much smaller, and so it's not the low hanging fruit. It's not something for which it's obvious that the efficiencies that we can ultimately gain would justify the cost. What actions can UC San Diego take? If they have a different price than Sea World? They cannot move, nor would they want to. They're in La Jolla. Why would they want to move?

Question: Right. But you wouldn't argue Malibu versus Tehachapi has the same demographics. Right?

Speaker 1: Right, but I guess the issue would probably be, if a price spike is going to occur in La Jolla at a different time than it's going to occur in Malibu, then ultimately, yes, it would be nice to be able to respond with that kind of granularity and have UC San Diego act to that price spike.

The reality is, that's pretty rare, and so you're not going to get a lot of gain from that. When the price spikes, it probably spikes in Southern California or in the San Diego area, and the kind of granularity we're seeking, actually--we already have differentiation between Malibu and UC San Diego, because they're in different load aggregation points already. But do you need it between Mission Beach and La Jolla? And I think the answer is, there may be some gain there someday, but it probably doesn't justify the cost today, and let's focus on the stuff where we do have great potential efficiencies. And I think the time of use is a better use of the technologies that are coming in the near term to gain significantly than the geographic differentiation.

Moderator: Gary, can I follow up and ask you a clarification on all that. I mean, one of the ways in which I would expect geographic granularity to be beneficial would be in relieving congestion where there's congestion on the transmission system. That might not be hundreds of different nodes or even thousands of different nodes in your system. But there may be areas that you could identify with groups of nodes where it would make sense. And have you looked at that? And how does that play out for you?

Speaker 1: Yes, and so what's going to happen is, there are certain limited spots on the system because of transmission limitations, where you end up with these price spikes more so than others. But that's not generally in load centers where there's a lot of load that's going to take advantage of this granularity. And, again, the low cost or the low hanging fruit solution is probably modifications to the transmission grid in those areas that have frequent problems due to congestion. So again, I'm not saying that there aren't things there. But the congestion that can be ameliorated by actions by UC San Diego is probably in a relatively broad area, as opposed to between UC San Diego and Mission Beach.

Question: Yes, and I guess my point is, we're sort of an infant technology, and so we're trying to get in here in a way that's meaningful and helpful, and if we don't have transparency, if we don't have granularity, then at the end of the day, we won't know where to deploy our technology. And the answer reached through an engineering study will always be to build out transmission and to build out distribution. So we're looking for partnerships. We're looking for information. And again, San Diego's probably not the best example, because it's a very small service territory. It's 5,000 megawatts in a 23,000 megawatt service territory, 25,000 megawatt service territory when they move up to PG&E. The averages are very distorting. And so, what we need is just more information to be a stellar technology.

Speaker 1: Yes, but I think we're getting to the crux of it, which is, if there is sufficient variation that it makes sense to have different prices reflected to customers, then maybe it starts to make sense. There isn't yet a lot of evidence that there's that much variation occurring. Certainly on averages, there's not, even though on averages by time of day there is. So as we learn more, we may find areas where geographic differentiation offers more opportunity, and then the costs may be justified. I'm not seeing it yet.

Speaker 2: I think there's another big issue here. It's the interface between the utilities and the wholesale market, in essence. And I'm working on an integrated demand side management cost effectiveness methodology for the future for all the utilities that are going to be bringing energy efficiency, demand response, distributed generation storage forward, which is in essence a model that Veridity is probably wanting to use, and particularly in the UC San Diego situation--in essence, a micro grid. Data transfer, automation, IT are issues right now. That's been explained in a report by the utilities to the Commission. I just saw it last week. I saw Edison's version.

And then how do you actually create that transfer of information? Can you actually tap the markets in the California ISO for all of the services that you would otherwise be able to affect and really gain benefit from? Those, to me, are the two big pieces. What's the ISO hand hold with the utility? And how do you then have access to it? It's a big issue.

Question: Yes, where do we go, and how do we get paid, are two obviously important problems.

Question: Let me try to marry the presentations that book ended this with Speaker 4's presentation on dynamic retail rates, which goes back, I think, to the clarifying question I asked Speaker 1. This seems to be a confounding problem. And let me put forth a straw man that says that we're really overthinking this problem.

And that's the following. And as we've discussed in the stakeholder process, the issue about rate design is such that I don't understand why you need different rates in different locations.

For example, let me put out the straw man of, say, a simple critical peak pricing or peak time rebate rate that would apply to all customers throughout the state of California. And let's just say, for example, you've got a flat rate of ten cents a kilowatt hour, and during critical peak times, it's a dollar a kilowatt hour. Or maybe that's your peak-time rebate. However, that critical peak rebate is triggered at a specific LMP level. Let's say for the sake of argument that's $500 a megawatt hour. Now, it's not always going to be $500 a megawatt hour everywhere in the California system, just like it wouldn't be when you're at super peak times in the PJM system. But it's going to be in specific locations, so that you don't have a different rate for all the customers. The rate is actually the same. But the triggering may differ by location.

And how do we know which locations to trigger it? Well, I think we're all pretty familiar with geographic information systems at this point in time. I mean, we all have GPSes. We can actually map out specific buses on our system to customers who say that we're on this dynamic retail rate, and we know that at these prices, what kind of response we'll get. Or they can actually bid that into the market, so at least operations has an idea of how we're going to see load react when LMP reaches a certain level. Which also then gets us around this issue of load forecasting. We still have the load forecasting problem for what we would say is non-price responsive demand, demand that we just simply take as given. But for price responsive demand, we actually see a load curve that's bid in, as you would see a supply curve bid in. At various prices, this is how much the load will consume. Which also gives us an idea when we get into those high price periods how much load should come off, and then we have an idea of how much capacity we're going to need. So you can tie this into the capacity market. This is something that we're working on in PJM.

So my question is, why are we so fixated with having the different rate when we could do something as simple as this? And then this actually helps Speaker 4 out in what he's looking at and proposing. We get a dynamic retail rate. It doesn't have to be real time LMP. It's not real time LMP or flat rates. There are a continuum of dynamic rates in the middle that state regulators could choose. And in this way, also, the state regulators should not feel threatened by RTO markets or by FERC jurisdiction. We're leaving the retail rate-making to the states, where it belongs, so that commissioners can go ahead and set whatever dynamic retail rate they want, tying it to the PJM real time LMP to get that reaction.

And the same would be true here in California. The CPUC could set any type of dynamic retail rate it wishes. It just has to be linked somehow to the LMP, and so the translation that we're looking at to bridge the gap between wholesale and retail is LMP. That's the common language at the wholesale level. Even though customers may actually never be charged LMP. But that's what you're translating to trigger the dynamic retail rate. And I'd like to the reaction, not only from Speaker 1 and Speaker 4, but from Speaker 2 and Speaker 3 as well.

Speaker 1: In terms of demand response, the situation you describe is actually I think the situation that we're in today. In other words, one of the reasons why we don't believe we need to go to geographically distributed rates is because for things like demand response, they can do exactly as you suggested. They can take advantage of the geographic differences in the system already by when and how much is bid on demand response, based on what's going on at the LMP level. So as you said, you don't need to redo the whole rate structure for that. As far as bidding in load to reflect the demand response pattern, basically bidding in a demand curve --

Question: Could I just clarify what I meant? It's not the demand response. And let's think outside the box here. I'm not thinking about demand response in the sense that we've always done so in utilities as a supply resource. Demand is on the demand side where it belongs. And so what I'm saying in here is that the price-quantity relationship you're actually submitting as a load is how much I'm going to consume at various prices. It's not how much I'm going to reduce.

Speaker 1: Yes. And when we do submit a demand bid, we can reflect, on an aggregate basis, how much I'm going to consume at various prices. It's just that at this stage, we do it for the prices for the LAP (load aggregation point), not the prices for the node. So we're aggregating and reflecting those demand responses, and maybe that's an inefficiency. But is it worth going to all the trouble of differentiating to eliminate that inefficiency?

Moderator: Just to follow up and clarify your practice, Speaker 1, because I guess when you said this in your presentation, I was somewhat astounded. Do you not forecast load geographically? Because I know in other systems with which I've worked, doing forecasts geographically across the footprint becomes very important. Storms go through. You have different climate regions within your service territory. I would think that you were already--maybe not at the nodal level, but at least at some much more granular level than your whole service territory--doing load forecasts.

Speaker 1: Well, I guess it depends on for what purpose. Peak load forecasting for building out distribution systems is certainly done at that level. But the daily information that we use to figure out what our load is going to be tomorrow to bid into the market doesn't come from a disaggregated set of forecasts that are aggregated up for the system. It comes from a forecast for the whole Southern California Edison system.

Moderator: I guess that surprises me a little bit, given my experience elsewhere.

Speaker 4: I'm intrigued by the concept. I think, in practice, if I understand it correctly, it could run into some self-selection problems in that what you're essentially saying, I think, is that the pricing point for the critical peak pricing would change to reflect the difference in cost to serve customers at that location. Right? Is that what you're saying?

Question: Correct. So everybody actually faces the same rate, but for example, suppose you've got two customers otherwise identical. One is on the upstream side of the constraint, and one is on the downstream side of a constraint. Chances are you're more likely to trigger the critical peak rate when you're on the downstream side of the constraint than the upstream side, which is exactly what you want, because that's where you want the response.

And we have situations in PJM, as I know you're well aware, where within a zone, if we just send a price signal to the zone, we actually might get demand response in the wrong location, and actually make transmission constraints worse, not better. And we face that in a little bit further west in our system, and also along the East Coast, especially in the Washington, DC, area--and you guys helped us out a great deal when we called for very specific demand response in the Washington, DC, area, both out of season and during the summer. And so that locational aspect is really important there, because if we had called it in the entire PEPCO zone, we could have actually made the problem that we were trying to solve worse and not better.

Speaker 4: And I think we do what you're describing. Maybe I wasn't communicating effectively, but we would trigger the demand response action in the area where the system needs it, regardless of the fact that the retail rate being charged in the two areas is the same.

Speaker 1: But here's what I think about the self-selection problem. It seems to me, if you're going to keep the rate the same, but just adjust the trigger so that essentially all customers are paying about the same, for those low cost customers, you probably have to curtail more and longer, because the amount of savings from them per curtailment is less than a single curtailment in a high priced. It could be just one curtailment. But to get the same correction with the single rate in a relatively low priced area, you've got to have heat wave pricing, which is a new term for me. It's seems to me you have to have a lot more curtailments. And so you probably won't get it, which is probably OK, because it's less valuable there.

But it does seem to me that you have a self-selection problem. I don't know. It's an interesting concept, but I think you need to think through some of those…

Question: I understand that it might create some issues and some complexities in terms of revenue recovery from a retail rate making standpoint. I understand that. I think that's what you're alluding to, if I understand you correctly. But on the other hand, that's not the RTO's or FERC's role to get down into that detail. And so we're properly leaving it to the state commissions to make that decision. We don't want to be presumptuous or arrogant--to say we know how to do this better. No, we don't. You guys know how to do it better at the state level.

Speaker 4: I think there's a lot of wisdom in what you've suggested. And I think critical peak pricing in some form may well be where we land, and that's OK. You can't let the perfect be the enemy of the good, and getting a good solution rather than a perfect one can be acceptable.

One of the issues with how you laid it out, though, is what are we doing about customer messaging under that proposal? In my view, in order to make this tenable or more tenable for the customers, you have to… I'm almost thinking that you could print in the newspaper that for certain areas, today is going to be a peaky day, a hot, high price day, and have them respond. So I'm not sure that if you only find out that you're over $500 in one area at 11:00 am, I don't know how customers are going to feel if their price goes up at 2:00 pm. So that's one aspect.

And Connecticut being a retail choice state, I don't know how to take your approach and move it over into that context. Do we require, as I suggested, that no matter what your offering is, it has to be at least this dynamic at a critical peak pricing time? Maybe that's a potential solution.

And then the other thing--I know it was just an example, but actually, from what we've noted in Connecticut, the ten cent to a dollar isn't even enough. It's got to be even more than that.

Question: Oh, sure. I was just trying to give an example. But I think the point that you bring up about education and notification, and this goes back to the moderator's initial remarks on this panel, is that technology has come such a long way, that this can all be automated seamlessly without the customer having to think about it. It will simply happen. And that makes it a lot easier, and actually, that probably makes customer acceptability a lot better, because they can set it and forget it.

Speaker 4: If we get there, that's fine.

Speaker 3: Just a quick point. Do you think that PJM can offer this, not just for LMP, but for the whole set of services? Because so far, there's just a certain set of customers who are usually very large industrial customers that can play in one segment of the game, LMP, and make this cost effective to even transact. The transaction costs are too high. So in other words, are you able to create this for all the ancillary services, the capacity market, and LMP?

Question: Yeah, that's actually a good question. And the answer is that the same concept that we're talking about can actually be used not only in the energy market, but then also dovetails in with the capacity market, because if we have an idea that when we know that we're going to hit our peakiest prices, and we have this price responsive demand telling us how much they're going to consume, that gives us an idea how much capacity we need to buy. So implicitly, those customers are reducing their capacity obligation, so they're getting that capacity value, rather than having to buy the capacity, as is the current practice today, and then having to sell it back. So you get that benefit.

Now, in terms of ancillary services, it wouldn't be a big stretch, at least with respect to reserve products (so a synchronized reserve, non-synchronized reserve, etc.) that we could use this technology to go down that same path, because as we get shortage pricing in, whenever we get an order from FERC, then we're going to cooptimize energy and ancillary services so that prices will be set simultaneously. So that signal could also be sent for demand resources that may be also providing synchronized reserve or non-synchronized reserve, as well as any calls that go out for the reduction to occur if we have an event on the system.

Regulation may be a little bit more difficult, but we already offer for demand response the ability to participate in the regulation market, but we just haven't had anybody actually do that as yet. But tariff provisions do exist.

Speaker 3: Yes, I think ideally you need all those pieces. I mean, I'm thinking of the example of UC San Diego, where they need to be able to tap everything they can get in an IDSM format. We want to be able to tap everything we can get. And to do it only piecemeal, or to only get part of it, makes it a barrier.

Question: The more that we can do with the same technology and the same paradigm, absolutely, the better off we are. Absolutely.

Question: And if I could just add for Speaker 3, what we'd like to do is instead of an administrative "push this button for this area" approach, is get some prices that allow the demand response to act in that area first and see if we can get our signals in front of the sort of backstop solution.

Question: I just wanted to tie together our first panel and this panel. One of the observations in the first panel is the price suppression effects of renewable energy and other types of subsidized resources, which in California in the future may include storage. So when I looked at some of the simulations that we did of just a few years from now in California, and then certainly out to ten years from now, you know, what you see is, LMPs are very suppressed, and even the peak/off peak price differences are very low, because we have wind off peak, and we will have a lot of solar on peak, and that will be taking away a large chunk of this peaking requirement. And then we'll be putting on a lot of gas generation on reserves, and that will be suppressing prices even further. So it's going to be a very different pricing environment if all these policies unfold. What you may see is very volatile pricing in the midmorning and midafternoon as wind and solar ramps take place in California, and that may be where the value to demand response comes in. But the price signal will be very different. (Again, this is all hypothetical. This is the future policy world.) The price signal would be very different than it is today.

And I really am not sure what value demand response will pick up in that environment. There will be a lot of other changes happening simultaneously to address the supply variability and the need for reserves. So it's an interesting future world. Rates will be going up. But the response to that on the demand side will be more like energy efficiency than demand response, possibly. Anyway, just a thought that had occurred to me as I looked at the simulation results.

Speaker 3: I think that's right. I just want to thank you for your studies and work with ISO and all the other people. Edison is deeply involved in that, I know. I think I would emphasize for the entire group here that ramping capacity, ramping product, instructed energy will be a huge problem, and particularly as the other prices, as you point out, may be diminished in very significant ways at certain times because of all the renewables. So now we're talking about in this nice, well behaved market 500 hours of need for significant demand response to really change things and really change the market. Now you have--maybe it's 500 or 800 hours, but you don't ever know when it's going to be. So it's going to be a very different thing. It means that the emphasis on "critical peak pricing" is critically important, but it has nothing to do with the historic peak of the system.

Moderator: I'll just add one other comment. One of the things that we've seen in some of the experiments with dynamic pricing is that you actually get demand side technologies that are able to respond much more rapidly than existing approaches to regulation. So there are actually some folks looking at microsecond responses, which become very important if you've got variable resources on the system. And that may be a significant source of value as we go forward.

Question: From a customer's perspective, I just want to say the question is very simple. People should pay for what they're using, and that's a very simple question. But one thing that the consumer groups react to with dynamic pricing is the [potential impact on] simplicity and stability. The customers really value stability. In energy crises, what we find out is that people are willing to pay a little more for hedging, just to know what's going to happen in the future. So this is something that we want to get really right, but we can't. Second, we have to value other things that maybe you can't model.

So this is something that everyone should have in mind when you say we want to go to dynamic pricing. And that's why they react. So it's not that they don't want to pay their fair share. They're just afraid of not knowing what's going to happen. So this is something you need to consider.

Speaker 4: Let me make that point again, maybe in the context of large commercial and industrial customers, because it may well be that they could save money on their electricity bill if they go to dynamic pricing. But maybe they won't choose that. Maybe they want to hedge. Well, why do they want that hedge if the hedge over the long term is going to cost them more? Because maybe their investors want to get a dividend payment every year, and in order to insure that that can happen, they need to firm up their energy spend. And that's a rational economic choice.

So I completely agree, but it's not just a residential thing that we're willing to kind of pay more for some insurance, to have a hedge. I think it's true across the board for completely rational reasons. And again, if customers want it, I'm all in favor of them having that opportunity. But I think there may be rational reasons that they may not want it, and therefore, it would be really unfair to impose it on them.

I will stay out of the opt in/opt out debate. I mean, because I see sort of going either way, with behavioral economics versus sort of my 89 year old grandmother now having to rationalize her electric bill. It's a legitimate debate. But I just think that choices are important.

Speaker 2: I think you're right. I think a lot of customers do value stability. It's hard to know how much. It's like the reliability versus cost controversy—stability versus lowest price. I mean, we also have a service territory, the United Illuminating Service Territory, with very high uncollectibles. So should I get those people stability even when it costs more and ramp up those uncollectibles a bit more? Or should I aim that we have the lowest possible standard service price that we can reasonably achieve for United Illuminating? And I tend to gravitate toward the latter.

Question: Well, my point wasn't that you shouldn't get it right, but my point is that things should be simple for the customers to understand. And I'm talking about residential customers. If you make all sorts of different very complicated models, you're going to get reactions from people. So they should be simple. As it is, it's very difficult in California to understand your bills. And if things get worse, you know, I just don't know who is going to explain to them what this bill meant.

Speaker 2: Right. And maybe for residential customers, this problem won't be solved for a while, and we won't even have critical peak pricing, or maybe not even peak time rebates for residential customers. But I wanted to address the possibility, so I spoke to it. But you know, it's possible that in many areas this problem, which isn't the biggest problem we have, in my view, won't be solved.

Moderator: Just to follow up, a couple of observations. One is, I think a lot of customers don't even know what a kilowatt hour is. I mean, we're talking very low levels of education in many instances. And so what they focus on in many instances is, what's the bottom line on my bill? And so to the extent that we can create options which provide them some stability in their overall bill, but still marry an element of insurance or hedging, with a dynamic signal that the chip in their refrigerator can use to address the value that it can create for the grid and help them capture some of that value, that's the best of both worlds, and we need to try to figure out, I think, how to get there.

Question: So I'd like to follow up on something that was said earlier, but it also speaks to what Speaker 2 just observed. And it seems to me that some of the concern about flat rates coexisting with dynamic pricing are really implicit criticisms saying, the Public Utility Commission is going to be swayed to set the wrong rate or somehow is not going to appropriately price the risks to a retailer of setting a flat rate.

And so first of all, I'd like to know whether you agree with that or not. And second of all, and perhaps Speaker 4 is the person to answer this, to what extent does retail competition--in other words, getting the PUC out of the game--fix that--make it completely moot? Because the retailer can set a flat rate. He can set a time of use rate. He can do whatever he likes. And he either gets customers or not. Great.

On the other hand, I can tell that some people would want to argue that the PUC is needed to show leadership in perhaps showing the technological possibilities for these things. So I'd like to know, is it a concern about the PUC imposing the wrong rate on Southern California Edison? Is that an issue or not?

Speaker 1: Well, I certainly have that concern in the sense that the debate seems to be associated with voluntary choice of taking this rate--opting out. That suggests that the otherwise applicable rate isn't changing. And yet what we're talking about is a change in paradigm where you're either going to go on the dynamic pricing, or you're going to pay the cost of the hedge to be getting a flat rate, which means a different rate than you're getting today. That doesn't appear to be the language in the debate. So I do have that concern.

Question: So then following up on that, should we just restructure the retail and do away with that problem?

Speaker 3: If we're going to restructure the retail to put dynamic pricing out there, then we probably ought to simultaneously restructure the rate that the customers that are not on dynamic pricing are going to have.

Speaker 2: I'm a retail choice advocate, so I would prefer to see the retail market take care of it. But then you have to wonder whether the retail market will take care of the policy objectives. For example, in Speaker 4's nightmare that the retailers would start talking about dynamic pricing as scary, calling it heat wave pricing, competing directly against it and trying to keep it from gaining customers--you may get that. You may get that. And then if the regulators' objectives are not being met, because you don't have dynamic pricing showing up in the market, I don't know what you do about that. It's either laissez-faire or not in the market.

Speaker 4: May answer may be too Connecticut centric, but that's where my experience lies. Our retailers don't offer anything jazzy to residents. They just beat the standard service price with a different, usually flat, rate. So it hasn't been our experience that the dynamism would occur on that side. Now, maybe it would if we changed some things about. But first you have to clear the hurdle of, are you going to accept a smart metering infrastructure implementation program or not? And so first that has to meet a cost/benefit analysis. So then first I have to know the projections about how many customers are going to accept dynamic pricing, and to what degrees. And if that's not coming from the utility, and we still have a large percentage of people on residential basic standard service, if that's not moving at all, I think it's going to be tough for the utility promoting the smart meter infrastructuring program to meet the cost/benefit analysis. So if you don't clear that initial hurdle, the conversation doesn't even start.

Moderator: I guess I'll take the bait and respond just a little bit. I mean, one is that if you look at the data, and I've seen very limited data on this, but the data that I've seen suggests that the hedging premium that is built into that flat rate, if it's done on a sort of competitive auction basis, like a BGS auction, versus looking at the dynamic price, reaches 20% or more, in some cases. So there's potentially significant savings to the customer just from being on the dynamic rate and assuming some of that risk. And that's part of the competition that's going to have to go on here, one versus the other.

I guess the second thing I would come back to is that I think that what we do as regulators does matter. I think that where we set the defaults does matter. And that part of our job is not simply to be an umpire calling balls and strikes between people who have their own private interests, but to actually think in terms of the future and the kind of future we need to create, and that's one of the reasons why this dialog is so helpful to us, because it enables us to do that. So with that, I think we can bring this session to a close, and thank you, HEPG, for allowing us to have this conversation.