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Rapporteur's Summary***Session One.****Residential Demand Charges: An Economic Necessity or Political Fatality?**

Residential demand is in the throes of fundamental change, making it less predictable and more challenging for load serving entities. Contributing to the volatility of demand are a variety of factors, including rooftop solar and other forms of distributed generation, energy efficiency programs, electric vehicles, and storage. There are also new technologies and programs available for customers to control both their demand and consumption. They include smart meters, automated appliance controls, software that enables the queuing of demand, and, of course, time sensitive and dynamic pricing. Given all of these developments, it is no surprise that there are increasing calls for applying demand charges--traditionally applicable only to industrial and commercial load--to residential customers as well. The logic, of course, is simple. There is a fundamental problem. Either there will be a market where prices drive the decisions, or it will be monopoly central procurement. If the former, it is essential that the prices send the correct signals. To send the correct signals, tariffs would have to move to greater demand charges. The traditional arguments against residential demand charges, which have generally prevailed to date--namely that residential customers have less control over demand, that imposition of such charges adds considerable complexity to tariffs for relatively unsophisticated customers, and that, as a result, demand charges would simply increase prices with no fundamental effect on actual demand--still carry political cachet. Is that cachet, plus whatever substantive merit there is to the argument, still potent enough to declare residential demand charges dead on arrival? In recent decisions, the Wisconsin Commission and the elected Board of the Salt River Project in Arizona have decided to impose such charges. Are they anomalies or the harbinger of a changed environment? How are the politics around equity considerations changing? Can we have distributed energy markets without tariff reform?

Moderator: Good morning. I'm glad to be here. The first panel, as you know, is going to be looking at residential demand charges.

Speaker 1.

Thank you very much. Good morning. It's a pleasure to be here, particularly talking about residential demand charges—a really hot topic.

PHONE 617-496-6760 **FAX** 617-495-1635

EMAIL HEPG@ksg.harvard.edu

79 John F. Kennedy Street, Box 84
Cambridge, Massachusetts 02138

www.hks.harvard.edu/hepg

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What I will do just to get this started is make the case for introducing demand charges, and then we'll have, I believe, a different perspective in the topic from the next speaker.

Existing tariffs for residential customers, it's widely agreed, do not reflect the cost structure of providing electricity service to those customers. As you all know, existing tariffs are typically two-part designs. The first part is a fixed service charge expressed as dollars per month. Sometimes that number can be very small, like \$5.00. Sometimes, as is the case today for the three I.O.U.'s in California, the number is actually zero. And then for municipals and cooperatives, the number can be as high as \$28 or \$35. You go overseas, like to Europe, and the number might be even higher.

So there is typically a monthly fixed charge. Sometimes it's called a standing charge. It goes by many different names, but that's basically a small amount compared to the fixed nature of the costs of providing electricity to consumers.

The second part is a non-time-varying energy charge. It's a catchall term typically based on the load profile of the customer class, and whatever costs are not recovered through the service charge are put into this energy charge. It's a volumetric charge. It could be eleven cents per kilowatt hour, or depending on where you're living it could be 19 cents per kilowatt hour. And if you're in the nice position of living in Hawaii, it could be somewhere in the 35 cents to 40 cents per kilowatt hour range. If you live in Australia it could be a number in that range as well.

So by and large (including in Texas, which is very much like Australia in the sense that their network utilities' costs are fixed), cost recovery is still happening through a volumetric energy charge. It makes no sense at all. But it has been that way for a century and therefore we cannot question what's happened... Anytime you make a change there will be winners and losers, and

the fear of the proverbial upsetting of the applecart means no progress occurs.

And the excuse that has been given all this time is, "Oh, we don't have the meters. It'd be very expensive." Well, that excuse is rapidly disappearing, because now we have 50 million smart meters in the U.S.

So five currents of change are swirling around the rate design for residential customers. The first current is the emergence of distributed generation, which, good as it is for the environment, good as it is for the customers who are going with DG, lowering their bills, maybe from \$200.00 down to \$50.00, has created inequities among residential customers. Now you have the issue of who is paying for the grid. Those customers certainly are not. And so you are having this revenue shift problem occur among customers.

Current number two--people are finally realizing that rates should be based on the cost causation principle. Not just for the large customers for which we have had that for the better part of the last century, but also for residential customers. Current number three, as I mentioned, is the roll out of smart meters which make it relatively easy to offer demand charges.

Current number four--load factors are becoming worse and worse. Air conditioning penetration is rising. The climate is getting warmer and you have load factors plummeting. So you need some kind of incentive to clip peaks.

And current number five is that a few U.S. utilities and several European utilities have been offering these charges for years. So the objection that residential customers won't understand it, that it cannot be done, that it's incomprehensible, is really just a perception and not reality.

As I mentioned earlier, DG is good on the one hand and a challenge on the other hand. What's happening is that a cost shift is occurring

because tariffs are largely volumetric, and, through net energy metering, when customers sell energy back, the lost revenue is recovered from the other customers and there is this huge inequity that arises. With no demand charges, customers have no incentive to lower their kW demand. They don't even know what demand is, because there is not a charge that corresponds to demand. And scarce capital is not being used efficiently because of the absence of demand charges.

So how are some utilities dealing with the issue? Some of them are mandating demand charges for distributed generation customers, arguing that they constitute a class by themselves. You have a case in Arizona, for example. And then you have another option, which is the one being tried out in Kansas, which is giving distributed generation customers a choice between paying a higher fixed charge (substantially higher—if the normal fixed charge was 15 or 20 dollars, the DG charge could be 50 dollars), or paying the standard fixed charge along with the demand charge. And that's the proposal that Westar Energy has filed, for example.

So, just a quick retrospective on the theory of tariffs. I don't need to remind the people in this room about the Bonbright Principles. I have distilled them to just two basic elements here, economic efficiency and equity. And, of course, to the extent that you currently have a situation which is inefficient, in the sense that customers have no incentive to reduce demand and therefore you over invest in capacity, and to the extent that you have these inequities that I was talking about, you will have to deal with change if you go down that path. Another precept of rate design is that when changes are made, they should be implemented gradually.

So if you're a distribution-only utility, then what we suggest is a two part rate, where the first part is a fixed service charge and the second part is not an energy charge, which is what it has been all along, but instead a demand charge.

And then there are all these issues about how should demand be measured and I'm saving those for the discussion period. Should it be the customer's maximum individual demand, regardless of time of occurrence? Should it be their coincident demand? Should it be a bit of both? We had a very detailed workshop on that in Denver a few weeks ago, and there's a whole set of issues about how you measure demand. But really it's not that difficult. It's already been done for the industrial and commercial customers for 100 years. There is no reason to be original here. There is a lot of precedent to draw upon. We can come back to that issue.

So my argument is that it should be a two part rate, including a fixed service charge and a demand charge. And then if you are a utility that is also providing generation services, either because you're vertically integrated or because you're providing basic service, that's the third part of the rate. We then have three-part rates for those utilities. And, as I mentioned earlier, this has been the practice for C&I customers for the past century, and it was all inspired by the writings of an engineering professor, not an economist, Professor John Hopkinson in 1892. I have the reference in the appendix. The presentation was made to the engineering society in the U.K.--and not just the regular engineering society, but the society of junior engineers. That's where it all originated.

Coming back to our lovely United States, 19 U.S. utilities in 14 states already offer residential demand charges on an opt-in basis. And included in this category are large utilities such as Duke Energy, Georgia Power, and Xcel Energy. Of course, Arizona Public Service is the real recognized leader in the field. They have more than 100,000 customers on it. There's also one other company that has reached high participation rates. So two of them have had eight to 10 percent participation. And now, with the deployment of smart meters and distributed generation nearing the point of inflection, I think

many others are looking at it. The 19 utilities here already have been offering it, and just about every other utility in the country is looking at this. It's the hottest topic on the planet today. There have been meetings every other week on the topic. And it probably won't go away anytime soon.

Just a quick tour of Europe--since the end of the Second World War, some countries have charged residential customers for energy based on a volumetric tariff and for capacity based on their connected load. Whether you're in France, or Italy, or Spain you're born into it. There's no issue of transition, winners or losers. That's just how you're born. You're born into a world of capacity charges. And somebody said to me, "That's what we need to do, but it's too late. We're already born."

So that's the challenge we have here. We've come out of the egg, what do we do now? As smart meters, are rolled out, the capacity charges are probably be modified for the introduction of demand charges. Now, here is how it works in Europe. You have a connected load. You have signed up for it, you get a certain rate. Should you have a party, a big one, a wedding perhaps, in Greece, so then what happens? Blackout, if you exceed that demand, right? They have to come in and reset it. On a bike, somebody has to be coming over to reset it. They have gotten used to it, and I asked a person in France, and he said to me, "You know, Europe has a culture of conservation and United States has a culture of consumption, and so it would be very hard."

I can tell you it is hard, but it is happening. I was in Australia to discuss demand charges not too long ago, and there is a big proceeding underway. You probably know there's a group called the Australian Energy Regulator. The AER has asked each of the network utilities (and all they have there is network utilities) to come up with new tariff proposals. And those new tariff proposals are going to be filed this fall between September and November. When I was

there I heard from the utilities in at least two of their states, and they are proposing to go with demand charges. The ones in New South Wales may have a different viewpoint, but the whole issue is very much coming up because 15 percent of homes in Australia have solar on the roof, and that penetration is rising. They have net metering, and they have rates that are about 35 cents per kilowatt hour. And so they have to do something about it, because otherwise there'll be huge revenue insufficiency and inequities among customers.

The ideal tariff, in my view, would have several elements. This is a concept of rate nirvana. The service charge will still be there, yet the billing, metering and customer care, that's all it will cover. Then there'll be a demand charge, which will have several sub elements within it. There'll be a reservation charge for transmission and distribution capacity (you're connected to the grid, and whether or not you use it, it has to be there, and so you have to pay a reservation charge for that capacity). You have to pay, also, a reservation charge for generation capacity. (A small amount, but it's still there. Conceptually, it exists, so it's a question of making it transparent.) And then there will be a demand charge for actually utilization of that capacity--so a three part demand charge, if you will. And then the energy charge will still be there, if you're buying power from either your utility or a generation entity. And with all the smart meters we have reflecting the variation of the cost of providing power, it will be time varying.

So that's the proposal I have. Just to sum it up, what would your bill look like in this new world? The energy charge today is a dominant element on the bill. If you imagine a \$100.00 customer bill, \$90.00 might be for energy and \$10.00 would be the service charge. (Hypothetically, in this example.) These are all made-up numbers, by the way. Don't ask me which utility has that rate, but I'm sure you can all relate to it at some level. And then comes the division of the energy charge into peak and off-

peak, and then a demand charge, say \$40.00. And then the fixed charge stays what it is. And that could be a transition plan. And then ultimately you want to subdivide the demand charge into the reservation payments I was talking about, which are for the capacity just existing there, and the demand charge, which is for actual utilization of capacity. And that's the picture I want to leave you with.

Question: Could you explain a little bit more about the reservation charges for both transmission and generation?

Speaker 1: Sure. So, the concept is that some of that capacity has to be there to meet your needs whether or not you have any actual demand. And so that cost has to be recovered, and so it's recovering the fixed element through the reservation payment, and then comes the actual use of that capacity and the rest of the demand charge. So it's a two part demand charge if you will. The first part is a fixed element; the other part is a variable element.

Question: What are the units of the reservation charges? Is it dollars per connection, dollars per kilowatt, dollars per kilowatt divided by 47, or what?

Speaker: It would be dollars per your kVA or kW, and it's just expressed however your connection is measured.

Question: With respect to T & D only utilities, does it matter if the meters are measuring the inflow and outflow of your DG separately, so the customer is still paying their share of the grid? That's the first question. And the second, related, question is, why do you separate service charge from the utility charge? They're both essentially fixed costs, aren't they, for the T&D utility?

Speaker 1: Let me answer the second question first. The service charge here is just for doing the billing and metering and customer care. And

that's definitely a fixed element, but then comes this other issue of the grid, which is distinct from the service, and so the cost of the grid is being collected through the demand charge and the reservation payments. The reservation payments are fixed--as long as the grid is there, it's fixed. The demand charge can be based on the actual demand that the customer is putting on the system. So they can control demand. They cannot control the size of the connection and...so we'll come back, but would you mind restating the first question?

Questioner: In your analysis, do meters separately measure inflow and outflow from your DG system? In other words, the increase in DG really isn't effecting the overall consumption directly. The customer has to sell their power back, and it's measured separately and billed and credited separately.

Speaker 1: In some cases utilities have dual meters to deal with that issue. One meter is for buying the power. The second meter is sometimes used for quantifying how much they're selling into the grid, and therefore there's the issue of how much should they be paid. Should it be the wholesale cost of power? Should there be an adjustment for externalities? Should there be a value of solar? And then that's a whole separate conversation. But what I'm saying here is, if you have net energy metering, I'm saying the problem is not with the inherent concept of net energy metering. The problem is caused by the rate design being incorrect, and so once you fix the rate design, which is my proposal, then you don't have to worry about net energy metering causing revenue shift.

Question: This reservation charge gives me problems. First of all, it looks like it's a double count with the actual demand, but the other thing is that it seems to ignore the fact that a particular capacity resource, whether it's a generator or, say, a high voltage transformer, is capable of serving multiple loads with non-coincident peaks. How do you deal with that?

Speaker 1: Can we save that question, because it certainly is a philosophical issue, to some extent?

Question: You mentioned that there were two utilities that stand out, one of which is Arizona Public Service. I'm curious what the other is. The second clarifying question is with respect to your reservation charge, does each customer get to decide how much they want to reserve, or is it imposed, say, the same thing for all customers?

Speaker 1: Black Hills is the other utility, they're in South Dakota. (And might also be in North Dakota.) The reservation charge applies equally to all customers in terms of dollars per kVA or kW, but the actual magnitude of the customer's payment depends on the size of the connected load.

Questioner: So, it would be based on their connected load, as opposed to, like, in Europe where they each decide how much they want—like, two KW or 4 KW.

Speaker 1: In Europe it is also connected load. The engineer comes out and checks the size of the connection and says, "OK, it's so much," and new houses have quite a bit of engineering that goes into determining that charge. But I've discussed that with folks in the U.S., and they told me it would be next to impossible to know, because they don't know what the connected load is. They'd have to do a survey, so, again, I'm throwing it out as a theoretical concept that's worth thinking about. Maybe it won't go anywhere, but it certainly appeals to me.

Speaker 2.

Good morning and thank you for inviting me here. I believe it's my first attendance at any of your meetings. I know my role here. I'm the consumer representative. But I need to say that I'm not here on behalf of any client that I have now or that I have had or that I might have. On the other hand, many of the views that I'm going

to give you, rhetoric aside, do reflect stated policies of some consumer organizations.

I have taken the liberty of discussing in my presentation some issues that are not strictly related to demand charges, but related to what Speaker 1 has correctly said is a growing interest in discussing changes to residential rate design. And certainly the issue that is on the table in most states has to do with increasing the fixed customer charge. Other places are now talking about demand charges and how they might be factored into the process for residential customers, so many of my comments will go to both of those issues.

The background within which we must discuss these economic theory-generated proposals for residential rate design, I would ask you to consider in light of trends that are going on in terms of what customers are paying for essential electricity service. We have a lot of increased charges appearing on customer bills and reflected in customer rates that I would call mandates. I'm not saying they're wrong or that we shouldn't approach these issues properly, but the bottom line is that many of these charges and costs are being passed through to customers based on political strengths and weaknesses being promoted. And I've listed them all here (efficiency programs, smart meter mandates, renewable energy mandates, distributed generation and solar pv mandates, enhanced storm resiliency and distribution infrastructure investments, transmission costs, and low income discount or bill assistance programs). They're all familiar to you, I'm sure.

The bottom line is we have significant pressure being put on many customers in many states to pay for essential electricity service. The IOU average cost for a full bill is 20 cents per kilowatt hour for 500 kilowatt hours. It's a heck of a lot more than that if you're into the upper tiers, which charge a lot more for cents per kilowatt hour usage than the lower tiers. In Massachusetts it's 16 per cents per kilowatt hour

currently, and in New York they're paying some of the highest prices and rates in the continental U.S. A recent story made it very clear that the IOU's are paying much higher rates on average than the municipal or publicly owned utilities in that state. In Massachusetts the rate structure is designed as a fairly modest customer charge and a rate structure that assigns a higher price already to using electricity over 600 kilowatt hours. Plus, you have a transmission charge. Plus you have basic service adjustment factors and other details, all of which are listed on the customer bill.

Electricity is an essential service. If residential customers do not have it in sufficient amount, then you have dramatic adverse health and welfare impacts. And those who are older are paying a higher and higher portion of their income, much of which is fixed, for energy services, and electricity is the largest expenditure.

All of these discussions need to take place in the context that I think theoretically we all know, but which sometimes I think we forget. Rate design is a zero sum gain. You can punch the balloon in on one part, but it's going to pop out on the other. If you're promoting a rate that's going to "save people money," the bottom line is that the utility's going to have the right to collect their revenue requirement. And if we all start using less, they're going to start charging us more for fixed costs that they must incur to provide these mandates and the reliability that we demand that they provide us. Utilities are often covered or protected from lost revenues in between rate cases, but customers are not.

So the other trend we have to think about when considering these theoretical rate designs is that we do have retail competition, or restructured markets, in 20 states. And in these states (almost all of which are east of the Mississippi, concentrating in New England and the Mid-Atlantic and some in the Midwest) the wholesale market is not subject to price controls by retail

regulators. The state of Maine has no longer the ability to effect or to directly regulate prices in the wholesale market, the structure of the wholesale market, the way the capacity market is structured in the wholesale market, and so forth. But on the other hand almost all these mandates are designed to affect the price of electricity in the wholesale market. And many of the promises that were made at restructuring are now being made with respect to the mandates that I'm discussing here and that are being paid for by regulated distribution customers.

The theory is that this is all going to reduce our prices in the wholesale market. This is something that those who are paying for the mandates have little authority or power to make sure happen. Who are the losers with rate designs that shift costs down to fixed charges, whether they're demand rates or increased monthly charges? Low use customers, low income, fixed income customers, and those who are renting and living in units in which they have no control over the appliances or the housing stock that they live in. Who are the winners? Those who are most likely to benefit from these demand charges are documented to be on the upper end of the upper income scale. They're better educated, they're single family homeowners, they're wealthier than the lower middle class and lower income customers that I think we need to be concerned about.

So my question with demand charges is, why are we doing this? Is this being promoted to ensure that solar PV or distributed generation customers pay their fair share? If so, there are other ways to confront that issue--and it must be confronted. I would ask you to consider the alternative rates targeted to those who are responsible for the impact of this new system on the prices we're all paying.

Residential demand charges are often talked about by utilities as kind of responding to this death spiral idea, coming from the loss of sale

revenues, but I don't think that's really a legitimate concern or realistic problem.

Then we have the classic, "We need to send the right price signal. We need to tell people what the real price of electricity is." But in order to do that you have to have people who understand the signal you're transmitting to them, and then you have to have the means to respond to the signal. When the bills are unbundled and the rate tiers and tariff structures proliferate and the surcharges as required are listed, what signal are you actually sending and who can understand it? Consumers correctly focus on the total bill amount and how they can pay it to avoid disconnection of service.

Can you understand that price signal? That's Pepco's bill today. What signal are you sending? You've got distribution charges, you have generation charges, you have transmission charges, you have a three part rate structure. Who in God's green earth can figure out what you're trying to tell them with that? Georgia Power has one of the demand charge options that I think Speaker 1 correctly identified is being implemented today. And here is their website's instruction to customers about whether this might be something they would adopt. I'd like you to consider that instruction and education in light of what we think the vast majority of folks with a equivalent 12th grade education and knowledge of their electricity bill are going to make use of.

Commonwealth Edison is promoting legislation to promote demand charges, and, again, this is the sort of approach that is very scary for consumers. Do they come in and make a filing at the Commission in which they document the cost, justify their predicted participation, examine all the bill impacts, figure out the winners and losers, try to make a decision under the affordability concern that I think ought to be in consideration when this kinds of dramatic rate changes are considered? No. They go to the state legislature in Illinois for their mandates. Do you

really think the vast majority of residential customers with their 750 kilowatt usage are going to be engaged, understanding, and interested in all of these gory details,--four part rates, three part rates, demand charges, energy charges? In my opinion the educational barrier here is so dramatic as to make it somewhat laughable to talk about this as some kind of mandate or dramatic change at this point. I do not speak of the future. Things may be different.

But most customers would be very happy to hear of an option that's particularly targeted to people with central air conditioning, who are shown on the utilities calculator how this rate option might "save them money." They're interested in that. I get it. I've no problem with that kind of approach. But, what they're interested in is, will my total bill be less and, if so, is there a program I can participate in that is easy? And peak time rebates come to mind, and direct load control comes to mind, and so forth. So there are ways to get at some of the issues that I know many in this room are concerned about that do not involve dramatic changes in tariff rates or mandated changes in how customers use essential electricity service.

In my opinion a market for solar PV is highly dependent on subsidies--the tax payer subsidy and the rate payer subsidy. We've turned our rate structure from something intended to be a little bit progressive into something that is very regressive. And I don't think it's sustainable for the long run. Tariff changes are not theoretical discussions. They need to take place in the context of affordable, essential electric service. I agree one size doesn't fit all. What may work in Arizona, with their climate, their customer base, their prices, is not at all reasonable in a restructured market like New York and Massachusetts, in my opinion.

Rate design based on average customer class cost is not a sin. It is a legitimate and appropriate public policy. In my opinion there are some principles and policies that I would recommend,

and basically they would flow naturally from the comments that I've provided with you today.

There are winners and losers--let's figure out who they are. If in fact we're transferring wealth to the wealthy who can afford to participate in an optional program from the least well-off of us, who are unable to participate because of their housing, or their income, then I think we have to address that and consider it in the decisions we're making.

We have to consider short term costs versus long term costs. We're paying now for these mandates based on promises about long term advantages. Who is responsible for making sure those benefits actually occur? There's no one at local utility level in Maine that can make that promise, and regulators come and go, and I am very concerned about paying now for future benefits that are capable of not being provided at all in the current market structure that we have.

Another principle involves asking whether you can explain a rate change to customers in a way that points to actual monthly bill analysis and impacts, and that's simple for people to understand. My recommendation, if I were in charge of all of this, and I'm not, would be to design default rates based on average customer costs and as flat a rate as possible. I think the Pepco tariff I showed you is ridiculous in terms of "sending price signals." Customer charges should reflect the modest cost of connecting to the system, and not overall common distribution charges. Demand charge rates are highly unlikely to be appropriate for the vast majority of customers, but if you have the ability to offer a rate option along those lines and the costs are reasonable and the benefits can be proven to have actually occurred, then I say more power to you.

And, finally, we've got to reform these distributed generation net metering policies. Without question it's getting out of hand. If we have a customer class that is using electricity in

such a totally different way than everyone else in the customer class, they need to pay their fair share. And in my opinion they need to pay their full fair share of distribution services that they are part of, that they have to help support and that they will use from time to time. And that might be done through a demand charge approach for that customer group, and I don't propose to know exactly how that must be done, but in my opinion this reform is long overdue and is likely to occur in the short run rather than the long run. Thank you.

Question: When you say you're recommending flat charges, could you imagine flat charges like a telecom bill, where you pay \$60.00 per month no matter how much you consume, or you can have up to so much data, or up to so much energy, before you pay more? I mean, wouldn't that be a better flat charge than a kilowatt hour charge where you don't know how much you'll be consuming in each month until after the month is over?

Speaker 2: Consumers who are payment troubled know how much they're consuming, because they focus on what their bill is and they often enter into 12 month average bill payment programs. So you ask a theoretical question, and the answer is, sure, I could conceive of something in which people were offered these options, but in the real world what happens is that the folks who can only afford to pay the \$6.00 are signed up for this plan as a means to avoid disconnection for non-payment. And I'm talking about prepaid electric service in Texas. So, you've got to be very careful about how the program you're proposing is actually being implemented, and who is using it and for what purpose. So I'm not against experimentation, but I do think we need to focus on the bottom line. We need to find ways to continue to make universal electric service in this country affordable for all of our customers.

Question: My question is more around pages 10 and 11, where you talked about the losers and

winners under demand rates, and my clarifying question is, what is your basis for this? Any analysis or studies? Because we have been looking at it, and I would think it would be somewhat the opposite of what you presented. In other words, I think low use customers stand to win in a rate design where you move toward a kW rate or a demand rate, whereas the single family home or the high demand user would be technically the loser, because they're currently being subsidized, and I'm curious to what your basis is for your conclusions.

Speaker 2: Well, I do not have a bill analysis for you, and I am basing my statement on the notion that many low use customers have inefficient appliances and may need to use electricity during certain hours for family, health, and other purposes that would trigger this higher demand charge being imposed on them. It seems to me that all of our efficiency programs and our efficiency mandates are being designed to help people reduce kilowatt hour usage. And to suggest that some dramatic change and price signal can be sent and understood and that we would know the impacts... The bottom line is that the folks who don't have as much ability to make changes to invest in things--to use electricity at a different time, to buy the smart thermostat, to replace the refrigerator that's old and clunky in the landlord's multi unit structure--those are the people that I'm worried about when I make that statement.

Speaker 3.

Thank you very much. What I offer today is sort of a case study for how the three tiered, sophisticated demand rate really can work and be understood by customers and can be very successfully implemented.

My utility has had residential demand rates on the books since 1981. As Speaker 2 mentioned, they were initially offered as mandatory for all customers with centralized air conditioning. We realized that centralized air conditioning was really beginning to drive our peak demand, and

so we required customers who had centralized air conditioning to take a residential demand rate. Today, over 110,000 customers, that's about 11 percent of our customer base, have voluntarily opted to be on the rate, even though it's no longer mandatory.

That level of penetration was enabled by a couple of things. The first is our customer point of sales techniques and some website modalities that we were able to implement, and also the penetration of advanced metering technologies. Although in the early years we did offer the demand rate by using the registered data from a solid state meter, the AMI implementation that we have has made the more sophisticated rate structure easier to implement, so that's been beneficial.

To talk a little bit more about the evolution of our demand and time of use rates, I mentioned that the residential use of centralized air conditioning flourished beginning in the mid 1970's and began to drive our system's peak demand. And noticing the significant effect of air conditioning on our operating system, we requested approval of a mandatory residential demand rate for homes with new centralized air conditioning. It was a three tier grade structure with three basic components. The first is a charge levied on the highest kilowatt demand registered within a single hour. The second is kilowatt hour energy charges, for the total amount of energy consumed, and the third is a basic service charge. It also included a time bearing energy component, which at the time was 9:00 A.M. to 9:00 P.M., and that same basic structure exists today, although the time of use period has slightly changed.

In the 1980's, as we implemented an inclined block rate, which is our standard rate, and TOU rates, we made the demand rate optional rather than mandatory, and we have seen a change in customer subscription patterns. We have a substantial migration from the standard use rate to the time of use rate, so about 60 percent of

our customers are on a time of use rate. And we have some changes in the level of those that have opted to take a demand based time of use rate. So of the 60 percent of customers on a time of use rate, about a fifth of those are continuing to be on a residential demand rate. You see that trend graphically depicted here, where about half of the customers are on the standard inclining block rate, but the graph shows that as different rate options were introduced, more and more customers chose to be on the time of use rates. As you see, the time of use energy based rate tends to be the more popular, but we still have a pretty material subscription to our demand based rate. Another way of showing the chart shows the number of customers that take our standard rate versus our time of use energy rate versus our demand rate a little bit better, because it shows them as a percentage of the total share of customer count.

I think there are two things, really, to take away here. First, each year a greater percentage of our customers chooses to be on a time of use rate as opposed to our standard energy rate, so that's a good thing in terms of time of use. And, second, while most of our customers remain on the energy rate, more and more customers are choosing a demand-based rate. We've gone from seven percent subscription to 20 percent subscription over the years on the demand-based rate.

So, how did we reach our 11 percent demand rate adoption? First is point of sale. We were able to leverage customer service processes to educate customers on their rate options and finding the best rate fit for the customer's load profile. Demand rates, as Speaker 2 mentioned, tend to make the best financial sense to our higher-use residential customers--those whose average consumption is about 2,000 kilowatt hours per month, compared to the 1300 kilowatt hour average for our energy-only time of use customer, and our 700 kilowatt hour average monthly consumption of standard inclining block rate customers. That does not mean

however, that those low use customers do not actually benefit from a demand rate, and I have data to show that momentarily. It's also possible, of course, to redesign the rate that we have today in a way that's both revenue neutral to the utility and that has a very moderate impact on customers overall. We're trying to do it in a way that varies the bill impact to customers, plus or minus five percent, and we're having some pretty good success. If you think a little bit outside the box, compared to how you would normally think about doing a rate design, there's ways to implement tiers of demand and things of that nature to minimize the customer impact that you would have by introducing just a pure demand rate, as you would see historically here.

We also initially marketed residential demand rates with load control technologies that would help customers improve their load factor and limit peak demand, for example, by constraining your use of air conditioning and your electric clothes dryer and your laundry machine all at once. We're actually doing the same thing today in a pilot program, where we and other third party installers are deploying rooftop solar installations and other behind the meter load control technologies such as battery storage and Nest thermostat devices on 200 customer homes, and are requiring those customer homes to also subscribe to a demand rate. And what we think will happen is we're going to be able to see, through this pilot, how a demand-based rate can actually provide some pretty substantial synergies, sending the right price signals to customers and to vendors, of behind the meter technologies to figure out how the industry can stay sustainable in the long term, how utility demand rates can operate and also stay sustainable with the use of these third party technologies. And customers have better ways to control their bill, so we see it, hopefully, as the opportunity to have a win, win, win scenario.

Let me talk a little bit now about how our residential time of use demand rate is actually constructed. It has a demand charge that varies

by summer and winter seasons. The demand charge, as I indicated before, is based on the highest integrated one hour kilowatt read, taken during the on-peak hours in the summer month, in the billing month. So, by comparison, the typical demand rate for a commercial customer tends to be on a 15 minute interval; giving residential customers a one hour interval actually is a little bit more of a forgiving mechanism, so that if you have one period where you're a little thoughtless and turn on all your appliances at once, that won't ding you in the end. The demand charge collects infrastructure-related costs of the grid and fixes a lot of the cost shift issues we've seen with the increasing penetration of distributed generation and other behind the meter technologies. Our residential TOU demand rate also has a monthly service charge of about \$17.00 per month, which also collects infrastructure-related costs.

So, in total, on our residential TOU demand rate today, about 42 percent of the average monthly bill for our demand-based TOU customers collects our grid cost. 58 percent of the monthly bill costs is collected through an energy charge that varies both by season, summer and winter, and by time of day. And our current peak hours are from noon to 7:00 P.M. And that's something we're probably going to have to adjust going forward, because our peak, with the increased penetration of distributed generation, tends to be actually more about 4:00 to 10:00 at night, as opposed to from noon to seven. So that's something else that we're taking a look at.

Note that on our system, about 70 percent of the costs to serve our residential customers are grid related, and only 30 percent of the costs are energy related. So even this charge structure is not purely aligned with costs. Were we to actually make it perfectly aligned, you would see the energy charge go from about 58 percent to about 30 percent, and the 42 percent infrastructure charge go to about 70 percent. Doing that in one fell swoop, though, of course, would have a pretty substantial effect on

customers, and so that's something we certainly wouldn't recommend doing immediately. Nevertheless, our demand charge hasn't really changed over the past 34 years, and so we think it does offer some good data to step back and take a look at what is the impact on customers and whether customers can truly understand it and learn to respond to the price signals that it sends. The answer to that, I think, is that they do.

This chart compares the peak demand performance of our customers subscribed to each of our three rates, broken down by energy block. The energy blocks are low use customers from 500 to a thousand kilowatt hours, all the way up to our largest use customers, 25 hundred to three thousand kilowatt hours per month. What we've tried to do here is give an apples to apples comparison, so that what you see is that customers on a time of use with demand rates have a lower peak demand compared to both customers on an energy only time of use rate, and our standard inclining block. And so this really does show that no matter what type of user you are, if you're a low user, if you're a high user, you respond to the price signals the demand rates set. Depending on the block, demand based time of use customers save anywhere from 11 percent to 21 percent of monthly peak demand compared to our customers on our standard inclining block rate. And they shaved peak demand by anywhere from five percent to 15 percent compared to customers on an energy-only time of use rate. So time of use certainly sends some price signals.

You can increase the price signals and actually shave peak demand and therefore potentially long term capacity investments if you include a demand component in that basic rate structure. So this chart looks at the peak load shape of our demand based, time of use based customers compared to our energy only time of use customers. We are primarily a summer utility, so this chart shows a hot July peak day. And as this shows, our customers on a demand based time of

use rate really do lower loads during the peak period, compared to customers who are on an energy only time of use rate. They start turning on their appliances as soon as the on-peak hours are over. We realize now that we're actually have to broaden that peak a little bit, shift it, so that it actually collects charges during the peak.

But what the usage pattern shows us is that customers are paying attention. They know what the on peak hours are and they know how to behave in a way to keep their bills low, and they are actually responding to the price signals that this rate is sending. If all of our customers did that, if we had a full subscription to a demand rate, we would have a substantial unit cost savings. Because our unit costs for time of use demand customers is about five cents per kilowatt hour. Our time of use energy rates are about seven and a half cents per kilowatt hour. So, we would save about two cents per kilowatt hour if all of our customers were on a demand rate and actually responding to the price signals that the rate was sending.

So here are some things that we've been taking a look at to recognize that demand charges can be tough. What can we do for a residential customer? Someone who doesn't have a rate analyst to help them figure out how to manage their home energy use. What can we do to make the rate a little bit more forgiving? There are several ways to do that. With the current rate, we take a look at the highest peak hour and use a one hour integrated demand. If you use something like that, you get a demand of about 5.6 kilowatts. So, you take your demand charge, multiply it by 5.6 kilowatts and that gives you the charge for the demand of that month. Another approach would be even more forgiving. Let's make it five hours continuous rather than one hour. If you do it that way the calculation shows that this customer would be charged only a four kilowatt demand charge. So, it would be a less of a demand charge because you've got a more forgiving, broader time period. You could also do, for example, your top

10 hours averaged over the course of the month, and if you did that, somewhere in between you'd get about a 4.3 kilowatt demand charge assessed. So there are trade off's. Clearly there are different ways of doing it. You have less precise demand measurement if you take a more forgiving approach, but maybe that's a little bit more beneficial to residential customers. So, that's the kind of policy consideration that regulators should consider as they're taking a look at demand charges in the residential sector.

Of course, there are other options. I won't go into in any great detail, but do you consider only on-peak demand, as we do right now, or do you consider untimed demand 24 hours a day? Do you perhaps place a limit or cap on your total demand charges, so customers won't be penalized if they decide to throw a party and they just blow that one hour max? These are types of things again that we're considering and that regulators should think through.

So, in conclusion, looking at our 30 years of history and our very high penetration of demand rates, we've come to the conclusion that residential demand charges can work, and that residential demand charges can be understood by our customers. I'm one of our demand customers. I understand it. I have a Nest thermostat, and, granted, I run our rates department, but [LAUGHTER] aside from that, my husband gets it, and he doesn't know the difference between a kilowatt hour and kilowatts. He kind of programmed the Nest. They show you how to do it, and we can manage through the demand rate. Residential demand charges can reduce a customer's peak demand and result in a win win for both the customers and the utility. And technology like the Nest thermostat I just mentioned can simplify the customer's experience, and that should make it pretty exciting to figure out a way to get customers engaged in moving into the advanced energy economy. So, with that I'm done.

Question: Back on slide 11, where you showed the different options for calculating the demand charge, regardless of how you choose to measure the peak demand, whether it's averaged over some amount of time or it's the actual peak, aren't you essentially just kind of playing a game with how much of the charge you want to put into the demand charge and how much is going to remain in energy? Because as you shift from the absolute peak down to some lower average, you either have to change the dollar per kilowatt to keep that slice of the pie in aggregate the same, or you're just pushing the rest of the energy so, you're --

Speaker 3: Yep, absolutely. Either the energy charge or the basic service charge, or whatever other charges you want to put --

Questioner: So, in that case, what's the advantage, really, of shifting to some you know, lower representation of the demand charge?

Speaker 3: It really is about what you think a residential customer can manage at this moment as they transition into a new rate design.

Questioner: But, then why not just change the dollar per kilowatt charge that you're implying to that peak --

Speaker 3: Making it high or lower? Well, the other part is the price signal that it sends. I mean, you want to still have a price signal that makes sense to customers. I think that rate design is an art and a science. You can do it in many different ways and achieve the same ends. These kind of thoughts are just ways to make the concept of demand perhaps a little less scary for customers and maybe a little bit easier for regulators to implement. But you're right. There are several ways to crack that nut.

Question: My question is back on slide 10, which showed this same result which most smart meter dynamic pricing pilots show, which is that at the end of some period of time, people's

demand bounces back. Isn't this primarily the central air coming back on, because people who have made perhaps a conscious effort, or they're not at home anyway, to keep the temperature in their home higher at some point in the evening need to cool things down, because the residual impact of not running it at a comfortable temperature has been reached and they may have to, you know, lower the temperature of their home. Do you agree that's probably what's happening here, central air?

Speaker 3: I would say that central air may be one reason. It's driving the increase at 7:30, but in Arizona it's hot at 9:00. It's hot at 5:00, when you're talking about a July day. What I think the takeaway from this chart is, is that customers are responding to the peak hours and the understanding that they will be charged more in terms of the demand charge during on peak hours versus off peak hours. And were we to shift the peak, which is what we're thinking of doing, my hypothesis would be that you would actually see a continuation of the delta between the time of use energy only rate and the time of use demand based rate continued, and that that spike wouldn't occur until later in the day when it's cooler and they'll start thinking of other things to do. Can you pre-cool your home? Set your home to 60 degrees when you're getting the best advantage of time of use energy, off peak energy rates and demand rates, and so then you can carry that throughout the day? Customers will start thinking along those lines.

Questioner: I just want to ask, have you documented what appliances are triggering that upswing?

Speaker 3: No.

Question: You talked about the Nest thermostat. Do new technologies give customers opportunities, and make it easier for customers to understand and make it back of mind, so you're not running around turning things off, but it just happens?

Speaker 3: Yes, I believe so, and in fact that's something we hope to prove out through the pilot program that I mentioned. We have these 200 homes where we are putting the technologies on the customer's homes and requiring them to subscribe to our residential demand rate. And we think it will prove out exactly what you're saying and give us increased data to know what we need to do from a demand rate perspective to help everyone integrate, kind of synergistically, moving forward.

Speaker 4.

I'm very happy to be here. I'm going to talk about residential demand charges: are they a good or a bad idea?

As many people may know, electricity sales in recent years have actually been declining. This is a chart from a paper I recently did with co-researchers in Germany and Australia, and in all three countries we found that electricity use stopped growing around the time of the great recession, and then has not grown since. Time will tell whether this will continue, but it has been a trend in all three countries. Obviously there's been lots of talk of it as "spiraling." People, I'm sure, have heard that. We actually did a study last year to try to look at whether there, we thought a death spiral was plausible.

In this particular study the second line from the top, is what EIA projects electricity demand to be on a national basis, in a business as usual reference case. We thought they may have underestimated the contribution of efficiency, so that top set of horizontal lines has enhanced efficiency, effectively the same amount of efficiency that EPA modeled as part of their Clean Power Plan proposal, one and a half percent savings per year, ramping up from wherever a state happens to be at this point. We thought EIA, (and this was the 2014 EIA analysis, not the 2015) may have underestimated PV. Penetration was happening faster than they were projecting. That next set of lines adds in

some additional PV. Likewise, they probably were a little bit slow on EV uptake, which adds to electric consumption. So, if you look at the difference between the very top line, the dotted line and the solid line, that's additional EV.

When all is said and done, all these adjustments are subject to uncertainty, I'll grant you. We took midrange estimates, we thought. The orange is actually demand--in other words, flat. That will vary from utility to utility. Some states have more PV, some have less, some have more EV, some less, some do more efficiency, some less, some are growing more underlying demand. As a national average, we're seeing roughly a flat demand. This is very different from what utilities have done historically. Load has always grown. So instead of relying on growing loads to help take care of a number of issues, if it's going to be effectively a fixed-sized pie, we have to make sure we get the rate recovery right. That's a little bit of background.

One other bit of background--I'm sure people have heard about the duck curve, which is related to how, as we get more PV, as we get more people on energy efficiency, on demand management, the afternoon peak is tending to go down. This chart is actually tracking this effect in California for several years. The top lines are actual, the next lines are projected. And, as Speaker 3 pointed out, there is the evening peak. Everybody comes home, maybe ups the air conditioning, takes a shower, if they have an EV they plug it in, those types of things. Demand then is going up. This is another issue that I think we are going to have to be dealing with as we deal with rate design.

As a number of people have mentioned, there are three utility costs components. There's the energy cost--how much for fuel, and that's a variable component. You also have the capacity and demand (generation and T & D). This cost may be somewhat fixed in the short term, but it is very variable in the long term, because the amount of demand effects how much new

generation you need and where you have to buttress the system. Then you have customer charges, such as meter and billing costs. These goes all the way back to the Bonbright Principles, that Speaker 1 talked about.

I want to focus on that middle group of costs, capacity and demand costs. I think everybody agrees that a truly variable energy charge, that's billed based on KWh. If it's a truly fixed customer charge, like, you know, hooking up the meter and sending a monthly bill, that's a fixed customer charge. But what do you do about the in between costs? You have four options. There's the traditional volumetric KWh charge. That's what most people have been doing. I'm not going to talk about that. We're moving beyond that. There's a fixed customer charge. I'm going to talk briefly about that at the end. That's not the focus here. The other two options are a demand charge or an enhanced time of use rate, perhaps including critical peak pricing. So, I wanted to talk about those two.

So, demand charges. Clearly, as we've heard, smart meters make demand charges much more feasible for smaller customers. I think residential customers will not immediately understand demand charges. This will be perplexing for your average residential customer. With education you probably could get them to understand, but they were not born this way, as in you know, it's been there since their granddaddy was born. It will not be easy.

Another key question is, how do you define demand? There are multiple definitions of demand, and which definition is the fairest? You have one option, the customer non-coincident peak. That's whenever a particular customer happens to peak. So if you have some software nerd who likes revving up their home super computer in the middle of the night and that's when they hit their peak, that's when they will get their peak demand charge. A second option is you could do as Arizona Public Service did. It based the demand charge on each customer's

individual peak, but at least during peak hours. You don't care about how much they use off the peak. I think that's better. A third option is that you could do the customer coincident peak. You can define coincidence, but without getting into the details, there are possible variations. A fourth option is to take the maximum or average of three to five peaks, as some way to smooth it off a little bit.

When I talk to customers and people who have done some limited market research on this (and I'm not claiming there's tons of research) there's a feeling of, "Gee, if I happen to make a mistake once, I'm going to get dinged, and perhaps for a whole year." So to the extent you can even it out a little bit. I think that will very much increase the acceptance. Yes, it means capturing a slightly lower peak, but for some customers, even if you do an average of three to five peaks or various other variations that Speaker 3 pointed out, it may not affect them. I have a cousin who lives in Silicon Valley, and, yes, he has this whole bank of servers in his home, because he works there. His peak is not going to vary that much. Those servers dominate him, and, you know, swamp the air conditioner. I'm not saying he's typical; I just use this to illustrate. Not all customer's KW would go down if you averaged over a few peaks. My sense is that, both for fairness and for politics, we'll need to start thinking about coincidence in a peak hour, and we can define what peak means, as opposed to charging someone who happens to use a lot at three A.M. And we'll have to be basing peaks on some average. We're going to have to soften it a little. We can all debate how much, and a lot of that will vary from state to state, utility to utility.

OK, now I have a few slides from the Regulatory Assistance Project specifically on the idea of non-coincident peaks and why that's a bad idea. You know, the original non-coincident peak came about when you had demand meters that meant that you couldn't very easily look at coincident peak. Obviously, with the smart

meters, we can do it any way we want. We're not just stuck with an old technology.

If you focus on non-coincident peak demand, only the line transformer and service drop really handle the non-coincident peak. Most of the costs are upstream and are not based on non-coincident peak. Let's base the charge on something that is more aligned with most of the costs.

Also, individual load shapes vary. And what the system really cares about is not an individual customer. Here, for example are some results from a particular apartment complex in the L.A. area--one 26 unit building. You can see that the whole building peak is significantly lower than the sum of the individual customer peaks. How do we get at something more like the grouped demand total rather than the individual demand total, avoiding that non-coincidence peak? And here's one other bit of data. This is from a Southern California Edison load research sample of residential customers in 2012 (one utility, one year--obviously we need more data). The key line, I'd say is the line that shows coincident peak. The very low users are by and large not that coincident. The high users tend to be more coincident, so this gets at some of the issues that Speaker 2 was talking about. If you charge based on non-coincident peak, I think you may hit the low users. If you do coincident peak, it may be much fairer. The higher users, because they have higher coincident peaks, may pay more. (These are averages. Yeah, your mileage may vary. [LAUGHTER])

I wonder whether, instead of a demand charge with what for residential customers will be a major education effort, there might be some variation of a time of use rate that could be a better option. Effectively, you can incorporate the demand charge into the peak period rate. For the rates that Speaker 3 showed, I noticed that the difference between peak and off peak is about four cents per kilowatt hour. It sends a significant signal. What if the peak period

difference were eight cents? It sends more of a signal. Effectively, you're adding the demand charge, (And I use the eight cents as an illustration. I have no idea what the cost of service is in this case.)

I would say many more customers do understand time of use rates and demand charges. I grew up when we had the Bell system, and I remember that when I was in college, everybody would call home after 11:00, because the rates when down. You had peak rates, shoulder rates, and off peak rates. Even as my daughter who's just graduated from college was growing up, Verizon, on her cell phone, would have different rates for peak and off peak. So people are used to this.

Other examples. People certainly understand with airlines, for example. You pay more if you fly during a peak period, so people are more familiar with this concept. It still will require education, but it may be easier. You also have the option to set up more than two periods --like peak, shoulder, and off peak, something like that. I think that for residential you have to keep things relatively simple. Maybe three periods. I wouldn't start doing these five or six part rates. Here's an example. This happened to be developed by the Regulatory Assistance Project, but it's just a sample cost-based rate design. They have an off peak rate, say, of eight cents per kWh, a mid peak rate of four cents more, but then the on peak rate might it be 18 cents per kWh, and even conceivably there could be a critical peak rate (that could be much higher). I'm not sure if you want to do a four part rate. For those few critical peak hours, say, 10 hours a year, do you really zap it to them? Can you get the same effect in a way that customers would better understand and that would have a less of an education need?

Either way, I think you need to phase it in. Start with the highest users, perhaps with the distributed generation customers. Speaker 2 talked about that. Maybe include an opt-in for other customers. Over time, maybe proceed to

medium size customers, probably allow an opt out, so those who really don't like it can opt out as opposed to complain to the newspapers and the PSC. And then, last or never, switch over the smallest customers--conceivably even there with an opt out. And, regardless, plan for lots of education. Don't just do it and expect everybody to say, "Oh, OK, great." There needs to be lots of education, and some of the stuff that Arizona Public Service has done, I think, is a good example.

Very briefly, I wanted to talk about problems with just moving these charges into high fixed customer charges. It does basically increase the fixed charge, reduce the volumetric price signal, and reduces the value of energy efficiency savings, but it also tends to penalize low users who are more likely to be elderly or poor. The map there on my slide was one I took off the web, and it shows states where they actually approved or denied changes in fixed costs, including many pending cases. This is from a number of months ago. I'm sure it has changed. I just use it to illustrate.

To give an example, a study done by Christenson and Associates a few years ago for the Kansas Corporation Commission looked at what would happen if they increased the monthly fixed charge from the current charge, which was, I believe, \$10.00 or under, and made it \$20.00 to \$26.00, varying by the utility. They found that, depending on the utility and the season, consumption would go up from one to nearly seven percent. I'm not sure that's what we want to do with the fixed charge. I think we're much better off with time of use rates or a well designed demand charge.

If the issue is just fixed cost recovery when sales decline, there's decoupling as an alternative. In particular, it could buy time. I think we need a lot more data on how these different options work. People have been asking about how it is going to affect high users, low users, what type of impact we actually get. I'd love to see a lot

more studies on this, pilots, let's look at APS, look at other people, get the data--but decoupling can buy some time, and make sure you recover those fixed costs while we're getting more data, before everybody switches over to one or another.

This slide is a map of some of the states with decoupling or lost revenue adjustment mechanisms. As you can see, it's the majority of states now.

So, to conclude, the utility industry is changing. Utilities and regulators will need to change. I think rate design will need to change so that capacity and transmission distribution charges can be fairly recovered even if sales don't increase. There are also going to be lots of other policies that are important. It's not just rate design. I think energy efficiency is in the public's interest. It tends to be less expensive than adding new capacity and therefore benefits all rate payers. So we want to encourage efficient energy use, and not just encourage increased use, which means we need more capacity.

So for residential customers, I wonder whether the time of use rate may be the best option, but the demand charge is another option, particularly if they have some averaging over more than one period, and they are designed to be somewhat coincident with the actual peak, rather than a non-coincident peak. Any change in rates will need to be phased in and will require extensive customer education. And that concludes my comments.

Question: You made the point about fixed charges potentially being contrary to energy efficiency objectives. What about demand charges, where you might just be shifting demand to another time? Is there any concern about the impact on overall energy use, if we were to shift our usage in response to demand charges?

Speaker 4: If you have a demand charge, there still is a variable charge that the customer can control. It may have some impact on efficiency. I'd love to study that. My hypothesis would be that it has less impact. There was a study I saw out of Japan that kind of implied that, but Japan may be different from the U.S.

Question: I want to ask a clarifying question of Speaker 3. The energy time of use rates, are they the same as the time of use rates that are time of use plus demand, or are they different?

Speaker 3: They are different. We have modified the energy rates because they're collecting less of the infrastructure costs, but the ratio we still have is about a four to one difference, price differential on our time of use energy rate and on the energy component of our time of rate demand rates.

Questioner: And are, is the difference between peak and off peak similar in the energy only or is --

Speaker 3: It's identical, 12 to seven.

Question: I just have a quick one for Speaker 3. Doesn't your utility also have a TOU super peak tariff?

Speaker 3: We do not for residential customers. For our commercial customers we have a pilot super peak pricing program.

General Discussion.

Question 1 (Moderator): I thought I'd start by just asking the panel, based on hearing from your fellow panelists, were there any other comments that you wanted to make before we launched into the discussion with the rest of the group?

Speaker 1: Thank you. Yes, I do have a couple of comments to make based on what I heard this morning and what I also heard at other meetings

in the U.S. and actually also abroad--I mentioned Australia, but I was in Santiago, Chile two weeks ago and the same issues have come up there.

The first issue is the issue of education—"Customers won't to understand it," et cetera, et cetera... Well, as we heard from Speaker 3, if your mind is focused on explaining it clearly to the customer, you can do it and we have many examples of success. The Pepco bill that was put up there unfortunately is not just Pepco's bill, it is the industry's bill. By and large you see that impossible to digest bill that comes in and people immediately go to the bottom line and they ignore everything else, which totally defeats the purpose. So, we can improve bill presentation. It is not an impossible barrier. Everybody hopefully has been to high school. They've had a physics class somewhere along the way...

Comment: My dear boy. You are living in a dream world. [LAUGHTER].

Speaker 1:...KW and kWh should not be too difficult to grasp. [LAUGHTER] And whoever doesn't grasp it should be disconnected anyway...

What I want to do, though, is address two other issues which have come up regularly. There was a restructuring roundtable in New England where decoupling was put forward as a solution, and I respectfully would disagree with that because decoupling doesn't solve the load factor problem. It doesn't really solve anything, other than just guaranteeing that the utility gets its revenue regardless of what happens to sales. It could be weather, it could be the economy, it could be organic conservation, it could be anything, and decoupling is too blunt of an instrument to talk about.

The last thing I would say is that time of use rates, which I supported through analysis and testimony for years and years, suddenly have

become favorite topic of discussion. Given the alternative of demand charges apparently they look better; compared to the alternative of flat rates, they look worse. They do not solve the problem. Time of use rates do a good job of dealing with the cost of variation and energy, not of demand. We still need a demand charge to deal with the actual grid being fixed. So, that's sort of my quick take on some of the discussion.

Moderator: Thank you. Speaker 2, was there anything you wanted to respond to?

Speaker 2: Just a couple points. Almost all of the pilots that have been conducted talk about reducing peak usage. All of them reflect this bounce back that we've seen here with Speaker 3's data, and almost all of them document no significant overall usage consumption or reduction. They are not efficiency programs. So I wanted to make that point.

I was OK with Speaker 4's presentation up to his Regulatory Assistance Program chart on cost based rate design involving time of use and critical peak pricing.

Not all sizes will fit all systems. Arizona's system is low cost compared to anything we have going on in the Mid-Atlantic or New England states, and they have a climate and a penetration of central air conditioning that is vastly different from what you are going to find in Massachusetts, New Hampshire, Maine, and whatever, so different strokes for different folks.

And the other point I want to make is that the restructuring states do purchase default service pursuant to statutory mandates to eliminate volatility and emphasize flat and stable rates for default service customers. And it's over 50 percent of the bill. So the notion that these states are going to consider time of use pricing for that portion of the customer bill without statutory and dramatic changes which would be fought tooth and nail by ever consumer group in those states and in the country is not likely to occur.

So you have a very different situation in Arizona than you do in New Jersey or Maine or Massachusetts or New, or New York.

But we haven't mentioned a really good program that is a win-win. If you have these smart meters installed and you want to offer a peak flow reduction program, the ones that are the most popular, the ones that are the most widely being actually implemented as opposed to being discussed in back rooms, are peak time rebate programs. Or, tie your central air, if you've got it, to a thermostat with the direct load response program. The bottom line is that Maryland, statewide, is implementing peak time rebates. Illinois is implementing peak time rebates. These programs pay folks for reducing usage during peak hours and through their wholesale market capacity auctions they solicit people to bid that in and get paid money for doing so. These customers remain on what we call flat rates. Many of them have multiple rate structures, as I described, but they are not being charged extremely high prices--what my friend Mark Tony calls "punishment pricing," with critical peak pricing for folks who are in an apartment and need their air conditioning to keep folks healthy during really hot summer days. If you reduce usage you get paid for it. If you do not reduce usage, for whatever reason, you don't get a reward and you continue to pay your otherwise applicable charges. These programs work. PJM wouldn't be paying millions of dollars for the delivery of this program to the Maryland utilities unless it does work. And that is the kind of win-win dialog that I would hope we could engage in if we're talking about practical programs to reduce peak energy usage.

If the problem is sending price signals about the demand, then I don't go down that path as being what we need to do with residential rate design. But I did want to emphasize the peak time rebate program as a very widespread and in-use and popular program in several states.

Speaker 1: Are you suggesting peak time rebates for demand reduction that would be expressed in dollars per KW as opposed to the standard dollars per kWh?

Speaker 2: Well, you have to structure the payment to the customer based on the rate design that they have in front of them. And what they have in front of them is a cents per kilowatt hour usage rate design. So, the cents per kilowatt hour is what it is that they're awarded. \$1.25 for each kilowatt hour reduced by BGE and Pepco customers in Maryland.

Moderator: Thanks. Speaker 3?

Speaker 3: I have a couple of comments. One is that time of use alone does have its benefits, but, to Speaker 1's point, all it does is send price signals about what time of day you're going to change your usage. It doesn't do anything to manage your overall consumption. And, in fact, we've seen in California, with the enormous penetration of distributed generation, that there are times of day when utilities are actually paying for customers to take energy off their system. You see negative pricing in the wholesale markets, which tends to benefit people in Arizona, but if the utilities then align their time of use rates with that, they'll be encouraging consumption during midday, which actually is counter to, I think, what many energy efficiency advocates would want to see happen. The price signal with the time use energy component alone also doesn't do anything to encourage things like cost effective storage technologies or load management technologies, which also can be very beneficial from an energy efficiency perspective. So I think you lose the opportunity to get a wholesale price signal if you only look at one component, which is the time of use energy as opposed to including the demand component as part of that. And in fact when we compare our time of use energy customers with our demand customers, we see a significant improvement in load factor. I believe our demand customers have a 37 percent load

factor compared to our time of use energy alone, which is only 29 percent. So that improvement in load factor can result in substantial cost savings to the utility system overall.

And decoupling is beneficial for utilities, but it doesn't resolve the customer to customer cost shift we see from the penetration of distributed generation, which is something that needs to be considered.

Moderator: Speaker 4?

Speaker 4: I'll add a couple of things, particularly in response to some of the comments we just heard. When I talked about decoupling, I didn't say this is the long term solution. I said it might buy time for us to do it right. I know Wisconsin just increased their fixed charges quite a bit, because they were worried about the sudden onslaught of PV customers, and you know some of these customers, some of these utilities had 200, 300 customers on PV. They had a little time. I'm saying decoupling, if there's an issue, can buy us time to do it right.

In terms of time of use, my thought was that if you do need to figure out the demand charge and then how can you potentially integrate that into the time of use, then instead, just do the time of use the normal way. Whether that's possible or not, I'm happy to have a discussion. I'm not pushing it to the exclusion of other approaches. A demand charge, done right, is also acceptable. Peak time rebates we very much support; however, we have to be mindful of the fact that the peak is probably going to be shifting over time. We often have an afternoon peak. I'm hearing from a lot of utilities that we are often going to be moving to an evening peak, and things like water heating, even the clothes dryer, become more important. And if you want to talk really long term, I'm hearing some people predicting that we're going to increase the use of advanced, high performance heat pumps in lieu of some fossil fuel heating, and a number of

places may start becoming winter rather than summer peaking. Maybe not Arizona, but other places, so we need to recognize that loads evolve over time and that may also buy us some time, but there may be some long term issues.

The one other comment I was going to make is that the states with the highest electricity costs often are the states with the mandates. Speaker 2 made this point as well, and I assume Speaker 2 is referring to renewable energy as well as energy efficiency. I'll talk just about energy efficiency. We just came out with a study this week showing how even the nonparticipants often benefit from energy efficiency, because it helps defer capacity as well as T and D costs. (That's not always the case, it depends very much...)

And that reminds me that in terms of that chart I showed with the sample rate design, that was just illustrative. I'll be the first one to say that every utility is different. You need to look at your cost of service.

And one other point about the high cost states. They also tend to have higher wages. They have other reasons that they're high cost. If you look at the actual energy bills, as opposed to rates, the highest bills in the U.S. tend to be in the Southeast, with some of the lowest rates. The states with the high rates, due to the higher rate, due to efficiency program, due to other things, often do not have the highest bills.

Question 2: Thank you. For Speaker 1, I wanted to ask you a question about what you referred to as "currents" in your presentation. So, the first current was about the emergence of DG. Why not target a demand charge just for those customers, as opposed to everyone? And then the second question is about your current two, about the cost causation principle. Why is this a new thing, and why do we think that customers will understand this and have the ability to respond to a demand charge in general--not just those that opt into specific demand charge>

Speaker 1: Why not just DG customers for demand charges? Well, that's the approach that some companies have taken. They're seeing this primarily as a DG issue, and they want demand charges just for the DG customers. But everyone who's doing that has told me that their intention is ultimately to go down the road and make this applicable to all customers, because it's a question of cost causation. Cost causation applies not just to the DG customers. For industrial and commercial customers, for the past century, even without any DG, they've had demand charges, because that's just how the cost structure of the grid is. There are fixed costs, there are some varying costs for demand, and then there is the energy.

So it's just transparently sending a price signal based on cost causation to the residential customers in the entirety, so why just DG? Well, some folks are saying that the DG customers are sufficiently different in their load shape. Their load factor might be 10 percentage points lower, for example, and to interconnect the customers who are DG customers, there are extra costs. So some people have the view that they are a separate class of customers within residential and therefore they should have a separate rate. Why not all customers who are residential customers? Well, because of reasons that are so obvious that I won't mention them. In other words, there is the fear of a revolution and there is the fear of the fear of the fear, and so [LAUGHTER] even though cost causation suggests you go there, it's like you don't want a thousand people gathering in front of the state assembly building, multiplying to a 100 thousand, and all of that good stuff. But I personally think, from the economics view point, there is a perfectly good case to be made for applying demand charges to all customers.

Question 3: Speaker 2, I think you raised what's ultimately a very important social policy question in this arena related to whether cost causation is ultimately the only sort of objective

function that we should be solving to here, and in terms of today's presentations, in a lot of ways there are attempts to think about how we might get to a good way to allocate the cost of this service, based on that cost causation principle. But, as you discussed, some of the problems and challenges were the lowest income customers, and those, also, who may have for good reason limited access to and ability to change consumption. I think that gets us to a fundamental question: is cost causation always the right function to be solving to? And I would just be curious as to whether you think there is something else, and, if so, what that might be, because I think if we don't agree on that, we just end up talking past each other. And I think that's ultimately one of the reasons why we see the hesitancy to change rate structure, and kind of this idea of, "We'll do it slowly and progressively."

But whether you do it slowly or quickly, we're just moving, over time, to something that's pure cost causation. And if that's not ultimately what we agree is fair, we need to know what that other version of fair is.

Speaker 2: Well, obviously rates have to be based on cost. I mean, that's the nature of what the regulatory system is suppose to be providing to us--the regulator looks at what the utility says its costs are and makes sure that they're prudently incurred and that their profit making incentive is just and reasonable and not over reaching or under reaching. So the issue with rate design is you take the approved costs and you allocate them. And my view is that for the vast majority of residential customers those ought to be done based on imposing the average cost on that group.

There are others who keep promoting the notion of sending price signals through the rate design that is designed to achieve their preferred objective, whether it's reducing usage overall or reducing peak load demand, or just making sure people know how much it costs to produce

electricity. And that means changing the average cost approach into something else again. And my theme here is to suggest that when you do that you need to be very careful about the implications of any such proposal among low use, low income, fixed income, renters and others who are part of the vast number of bill payers out there who either don't want, don't have a preference for, or simply cannot respond to these more individualized price signals.

So we always have recovered costs. That's my point. What's happened with the DG issue is that with net metering, what was supposed to be a slight encouragement to stimulate the development of a socially desirable industry has turned into a significant wealth transfer and a shifting of costs from those who we know are more toward the upper income demographics to those who are in the lower income demographics. And that suggests that we have a group that needs separate attention for the rate design as a result of the very separate and clearly identifiable program that they're participating in. So if the problem is the DG group, you need to address that directly and solve that directly and do so fairly. But, when asked repeatedly whether they want time of use rates, I've not seen surveys that say, "Yes, I'm just waiting for my utility to offer me that. I want that. That's good for me." Where it's been sold are very warm climates to high growth central air conditioning states that have relatively lower costs compared to the Midwest, New England, and the Mid-Atlantic states. And more power to them. Build it from the bottom up. Where it works, fine, but imposing from above is my concern. I hope that answered your question.

Speaker 3: I'll chime in on that for a second. I that a three tier rate isn't necessarily reactive, and all about solving the problem of distributed generation, but more proactive. What kind of rate structure gives a little bit to all of the entities that are now engaged in the energy world? So it is both the customers, and this gives them all a means to manage their price signals in

a variety of ways. It allows third party technology vendors to find ways to make their system more cost effective, so that they're not dependent upon federal subsidies or the kind of inherent subsidies that are part of the net metering structure. And it gives utilities a way to potentially get their customers, if they all behave in response to the price signal sent, to increase their load factor, and that allows them to operate their system more efficiently. And so, if you look at it not as solving one specific issue, but in terms of what kind of right design do you need as a platform for the future, this rate seems to be right now sort of a happy middle.

Question 4: I would propose that if we're in fact aspiring to a nimble grid that can integrate renewables and energy efficiency and other elasticities of consumer demand, wherever the source, whether it's central or distributed, we're going to have to have a much more sophisticated network system and platform than we have right now. And a three part tariff structure takes care of those historic cost and causation linkages. But in thinking about the new grid, in my mind, there will be new operational demands. It's going to require balancing and a level of sophistication to get to this transactive platform that doesn't currently exist, and those costs, I believe, are not necessarily going to be capital intensive. So they won't be capacity oriented.

So instead of three buckets, where we have a customer charge, a demand oriented charge and an energy charge, aren't we also looking for some type of charge related to the operational costs that are going to be required to do that active balancing of a new network, and, if so, what does that look like and what is the appropriate cost recovery mechanism for that? Is that a kilowatt hour charge, is it a kilowatt charge, and shouldn't we be thinking about that now as we're developing that new network platform and not in the future, when we're thinking backwards about the fact that we haven't sustainably found a tariff to support the network system that we want?

Speaker 1: So that is a very real issue. What I would first think is that the best way to solve this is with smart consumers now having smart apps and smart devices like the Nest thermostat. Basically, the technologies are coming out to make you more aware of how much energy is being used, and if the system economics are changing, then I sort of rehash what Fred Schweppe said many, many years ago, that you have dynamic pricing, hourly, sub hourly, coupled with smart technologies, and that will deal with those operational issues that you're talking about. So it is part of the three part rate. It's just that the third part is now moving in real time, and with the enabling technology the customer will get a price signal that could say, for example, that in the middle of the day it's inexpensive. It could say that in the nighttime it's more expensive. It could suddenly ramp up or suddenly ramp down. Customers will have programmed their preferences into the home computer, and to the extent that they are participating in this kind of pricing, that will just multiply. They wouldn't ever think about it. Like people keep talking about doing laundry at two in the morning. That's not what the whole discussion is about. It's about how you set it up. So the energy portion of the rates, smartly done, will address the operational issues. It's still in the family of the three part rate.

Speaker 4: I will add just a little bit. Yes, there are going to be operational costs to integrate a grid, because it's much easier to integrate, you know, a hundred generation sources than a 100 thousand. My gut says that the higher users probably pay for it, but I think there will be capacity questions as well. We're going to need a lot more sensors on the grid, for example, to help do things. We're talking renewable energy. We may need to have some additional transmission to bring power in, so there's going to be some of both. Good question. We need to think about all those costs and anticipating them now rather than getting to, "Oops, now what do we do with these costs?" later.

Question 5: Why are we only thinking about dynamic pricing only in the energy context and not in the context of the distribution system itself? After all, at an individual customer level we care about the line drop, which was tied to the customer demand, but we're really thinking about what are the coincident demands of all customers on circuits, on substations, and it's not just on the consumption side, but it's also on the generation side as well. And as we get more responsive demand, as we get more distributed generation, there's certainly a potential to think about congestion in the distribution network and other things that go on in the distribution network and to begin to have prices that reflect that and potentially deal with the load factor issue, which is not just an issue in generation, but it's often worse in transmission and distribution. Shouldn't we be thinking about that? Granted, not tomorrow, and it may not even translate into a retail rate. It may be a question of how you get to the suppliers that are supplying the technology which could be something different. It could be a wholesale settlement. But shouldn't we be thinking about how you might dynamically price for those kinds of things that go on in the distribution network, as opposed to just having a reservation charge based on what the individual customer demand might be?

Speaker 1: There's a man at the Australian Energy Regulator by the name of Daryl Biggar. He's an economist and has a book out as well on the topic. He would support exactly what you're saying that you need to have--the same concept. The problem is that there's not enough load research cost of service studies to pin it down. So, in theory, yes. In practice, people still don't know how to do it. And I know that in New York they're talking about it. In California they're talking about it. Hawaii is looking into it as well, but the more I look at what they're looking at, the more confused I get in terms of what exactly are we talking about. So, it's still, I think, taking shape. It's like there's a void, and

everybody knows we have to come down here and do it. Like there's talk about developing an ISO for the distribution grid. Well, what exactly does that mean? And then they're bringing in the locational aspect. So you're going to have houses near each other facing different prices. I mean, is that how it should be? Do we have data to support that, and then ultimately, politically, et cetera, will that be acceptable? Those are the sort of things that will take, I think, several proceedings to sort out. But, yeah, I think it's unavoidable.

Speaker 2: It turns out that the notion of creating a market for distributed generation doesn't match with what the capacity and needs and locational requirements are for the distribution utility. People are installing this stuff in locations that are not appropriate for the planning of the grid. And what I see happening and nobody's admitting this publicly, is we're reintegrating our electrical system in a lot of the restructuring states, by taking the distribution utility and suggesting, as the New York Commission has, that we need distribution plans for the implementation of distributed generation. And so there's this big backroom fight going on. Is this a market or is this a regulated system we're going to have here? And the New York Commission is talking out of both sides of its mouth, in my opinion, and maybe doesn't really want to make a decision about this, but the idea of creating a plan that would allow the utility to actually identify the best locations where it would provide benefits for all customers to locate certain distributed generation facilities and then put them in the business of trying to stimulate the location of that in those areas is going to be a very interesting debate to watch.

But that's the real problem here. We've taken it all apart, and now, frankly, we're trying to put it all back together again. And my concern is the stranded costs and the implementation costs and the risk factors are all on the residential rate payers here. There's not a fair sharing of the predicted benefits, the allocation of costs

between the market and the regulator...but you know. You raised an interesting issue, to say the least.

Speaker 3: If I could just add one quick thing. At my utility, we do address coincident peak demand to get to the distribution charges that you're talking about. We just do it during the cost allocation phase of the revenue requirements proceeding. And so we bring those costs in, and then simply for the charge itself we use non-coincident peak to assess what your specific kilowatt hour charge should be. So we do bring those coincident peak demand charges into the consideration, but just for simplicity we then assess it based on the non-coincident.

Speaker 4: I was just going to add that, yes, we're getting congestion in certain distribution grids. We're going to have that more. There are many ways to address it. I refer to the ComEd experiment, Brooklyn, Queens, for example. I'm aware of a number of others. Rates are also going to be important, and thank you for raising it, but there's going to be multiple responses.

Question 6: One comment, since the PJM issue came up. Let's keep in mind that the capacity market which I think you're referencing, Speaker 2, those resources will only provide that benefit if they clear in the market. It's not as if we're paying them out of market. And so I think we need to be clear about that.

The other thing to keep in mind when you're comparing it to peak time rebates, is the issue that in the capacity market, we procure capacity for all of the demands as if demand response didn't exist, thence buying itself back. Peak time rebates, that doesn't exist. Effectively what you're doing is conferring a property right to the users without them having paid for it first and then actually getting money back for that without conferring the property right. So I just want to set the record straight on that, since you brought up PJM.

If we're so concerned about the issue surrounding customers and who's going to be hurt and so on, why is it that we haven't thought of doing a demand charge and volumetric charges based on the actual cost of energy? And if we're truly worried about those equality issues, why can't we move money around in the fixed charges? Has anybody even thought of this? I just want to get reactions from the panel.

Speaker 2: I don't understand the perspective that your question is derived from. The retail rate structure of course is a function of politics and litigation before state commissions as to what is an appropriate way to recover the utility's fixed costs. The generation part of the bill is passed through. So I'm not quite sure what you're suggesting ought to change. I didn't get it. Can you help me out?

Questioner: Let me be more blunt.

Speaker 2: Please. [LAUGHTER]

Questioner: You claim to be helping customers, and yet I think what we're seeing here and what ComEd is actually averring (in the earlier question) is that actually customers are better off under a straight fixed variable rate design or Hopkinson tariff or optimal two part tariff. And you've made a statement that that's not the case, but yet you already said that there's no evidence here. And yet Speaker 3 has provided evidence of some of the benefits of this. We know that ComEd has got that evidence of that. And so I'm suggesting that if it's truly an issue, then I'm suggesting another alternative. Go with the demand charges, and if you're truly worried about equality issues and so on, why can't you move money around in the demand charges between certain customer classes?

Speaker 2: Well, you're asking a question that needs to have the context of state regulators finding your question reasonable and statutorily capable of being implemented. But, putting that aside, the fixed charge issue has been routinely

fought and opposed by the National Association of State Consumer Advocates, AARP, Sierra Club, Citizens Utility Board...I mean, I could go down the list. They see the spreadsheets. They understand the implications of moving to fixed rates.

The demand charge issue is a different proposition, in the sense that there's not a lot of bill analysis work and ability to actually implement that in states. You have to have the smart meters and you have to have the ability to figure out exactly what the demand charge would be, how you're going to calculate it, what you're going to do to explain it, and you get all those costs and you take a look and see. Now, the demand charge issue needs more research, but if you're talking about offering an option to people who, like in Arizona, are the upper tier of the users who stand to benefit more, then you start off doing that and you will build some political acceptance for it from the bottom up. But beyond that I can assure you that fixed customer charge increases beyond what has traditionally been included in residential customer rates has widespread opposition from consumers. So it's not my opinion, it's the work that is being done in state after state.

Speaker 4: I will add, briefly, that I agree with your premise that it should be data-based as much as possible. There is enough data. Let's get it out there. I've seen some. My guess is that we may need more. For example, for the data that I've seen, if we do non-coincident peak, that may hurt low income customers, but let's look at the data, we can work it out. And you kind of imply, well, if the data seem somewhat reasonable, is there a way to, you know, have lifeline rates or something else? Yeah, absolutely, that's an option.

Speaker 1: I just wanted to add that there is plenty of data on the cost structure of the grid and all we're talking about is transparently carrying that forward in rate design. To the extent that we have social issues, let's have

some other mechanism for dealing with that. Let's have income subsidies. Let's have energy stamps, just like food stamps, and let's deal with the equity issue through those. But let's not mess up pricing, because that distorts resource allocation, and then all of us end up paying for that. It's just hidden. It's not transparent, but it's there. The cost is not being paid by the Martians.

Speaker 3: When we look at our lowest use buckets, we actually determined that you don't really need to assess a demand charge on low users, because the way our basic service charge is structured right now, the fixed cost actually already picks up enough of what they have caused, so I don't think you hit your low end users. You don't need to, because you look at all of your customers and you figure out what you need to do in order to fairly allocate costs in order to address what costs they cause. To the point the questioner raised, and I think it's a good one--what is the fear with just charging energy-based rates for energy, on the energy portion? I believe its fear. I do think that's the underlying piece. I think people are starting to understand the gravity of the cost shift and that something has to be done towards it. And you can't do it all in one swoop, because there are ancillary impacts that are very social and political, and so a transition needs to happen. But my personal belief is it needs to happen at some point.

Question 7: I think Speaker 2 has done a good job of raising another important aspect around, "Hey, guys, this has a big impact on a big class of users out there if you change the rate design and so we need to think carefully about that." And as I heard the panel this morning, I did come back to the basic question of, couldn't we target, whether it's a demand charge or an approach to what we think is a big impact around the distributed generation area, or the new technology usage? And how would you do that? So I think that was the first question asked, and I think the answer was, "Well, it can and should work for everyone to implement a retail

demand charge,” but I guess I come back to the question of, if one wanted to focus on the problem of the new technology of distributed generation, providing inequalities right now, and you didn’t want to completely disrupt this bulk of customers in a way that Speaker 2’s suggesting, how would you do it?

Speaker 2: Let me suggest that those of you attached to state regulatory agencies need to get on top of this issue. This solar PV industry, which is a profit making set of operations dominated by a couple large firms that are moving across the country like a tidal wave, taking advantage of this current net metering policy to sell contracts to customers and getting, all kinds of significant benefits, and alleging, you know, “Lower your bill. You won’t pay anything,” blah, blah, blah. You know, utility rates are going to keep going up. You need to get productive. These people are now getting so powerful politically that they are getting statutes passed in some states which prohibit the regulatory commission from setting up a separate rate design class for them, because they say it would be adverse to the development of this green technology that’s going to save America from pollution. And I’m telling you, if we don’t get on top of this pretty soon, we’ve already got a huge group of grandfather customers who are probably not capable of being touched with regard to paying their fair share of the distribution grid in California, Nevada and Arizona, but I think we need to get on top of this and get politically involved in trying to get an equitable solution to a group that is taking advantage of what was intended to be a short term subsidy, but has now become a permanent claim to not paying for what they are using, you know, not paying their fair share for the investment in the distribution grid. I don’t care if they get subsidies in terms of generation prices, but this not being paid for the distribution services that are vital to the health and safety of all of our customers has got to be addressed. And I shudder to think that we would be engaged in a discussion of how we need to

impose demand charges on all customers as a means of getting at what is in many states still a small, but growing, issue. It needs to be addressed directly.

Speaker 3: May I add to that? So, the demand rate that we have right now is actually imperfect. Were we to move all of our customers onto our current rate, some of them would have monumental bill impacts. And so what my team has been doing for the past three years is doing just what you suggest. We are breaking down all of our customers by classes, by type--who are summer visitors, or who, you know, have homes in Flagstaff, who are only here half the time. How are they impacted? How are our apartment dwellers impacted? We’re taking a look at all of those and saying, what kind of demand structure do we need to have in place to make sure that each customer class, to the extent they’re impacted at all, is impacted plus or minus five percent of a bill impact? In some cases actually it turns out that some of our lower use customers, as someone pointed out before, will actually benefit from this change. Those who are hit the hardest are those who have big homes and are only in those big homes half the year. If you implement a demand rate on those guys, they do get hit, and so the way to do it is just to be smart about it. Because we have AMI penetration. We have a lot of load research data that we can use to figure out exactly how it is that each will be affected, and how we can tier our demand charge so that certain customers aren’t overly impacted by it, and then find a transition phase, so that eventually you do the same thing, right case after right case for a period of time.

Questioner: So if you wanted to try to target that group that was using distributed generation, what would be kind of the most impactful way of solving the problem of getting them to pay their fair share, if you will, by impacting their rate structures and not everyone else’s? Is that clearer to you? Because I know you’ve done a lot of analysis.

Speaker 3: You could do that in a couple of ways. No matter what you do, though, you're going to be told you're putting a tax on the sun and you're going to get sued. But you can do that in a number of ways. You can do a fixed charge that recovers the full amount of your fixed costs. I mean, that's the whole net metering conversation that you know. You could certainly do it through a demand rate. One of our options in our filing that we made two years ago was to have all undistributed generation customers take service under our demand rate, and that certainly helps, although, as I've said before, you still don't recover all of your fixed infrastructure costs even under that rate. So some cost shifts still continue.

I view that as just a band aid to a problem though, rather than looking at something that will really give that platform for a long term rate structure, because it's not just going to be distributed generation. We hear all the time that battery storage is next, and so look at each rate that you propose in the context of the newest technology.

Question 8: Perhaps I'm being a little politically naïve or something, but I wonder why there's a need to offer a number of options for customers? Especially when there's the option to go from one plan to another, to another. It would seem that would just enable some sort of a game to occur. I mean that customers would find the one where they paid the least, and wouldn't you want essentially to have sort of cost based analysis just to determine, you know, what makes sense? I can see, politically, how there may be some classes that you wouldn't want to touch too much, or have them opt out if they didn't want to, but wouldn't you want to sort of avoid providing too much of an opportunity for people just to opt out of what's the right thing for them to do?

The reason I thought of this was that on your slide nine, Speaker 3, you had identified

different peak usages based on the plan people are on, right? The interpretation of that could just be a selection bias, where people who have a plan where they have a high peak use don't want the demand charge. So they just choose to opt out of that type of plan and into the energy used, as opposed to the understanding which you are pushing, which is that the behavior had changed based on the plan, and that was what caused the difference. And so that's a politically naïve question, but why is it a good idea to provide all this choice and people just sign up for the plan that's the best for their usage? Essentially to let them gain the system.

Speaker 1: Why don't I jump in? What I was going to say was that, ideally, from an economic perspective, you do a cost based study, and it depends on how many classes you want to have, but assume you come up with your definition of class, you'd have one rate for that class. That would be the default standard rate. Now, if they didn't like it for whatever reason, then you would offer some variations, but the default rate would be the ideal economic rate. Because otherwise you're going to have zillions of choices and how will you deal with those? New technologies will always be coming up. Load shifts will be changing. Well, the rate has to be dynamic, has to adjust with the new reality, but at the heart of it, it will be a good thing, at least in my view, to have one core rate and then have choices around it. But, then comes this distributed generation issue and there's all of this discussion that you brought up and that came up there as well. So, some people are saying, "I'm having a headache. I just need to focus on my immediate problem. And I want to make it mandatory for those. They'll have the demand charge because they're causing a huge challenge for us and they're growing fast. The other I'll deal with slowly." I think maybe politically that's the only viable option. If it were up to me, if I was the energy czar of the United States, I'd do it differently.

Speaker 3: And we have a number of residential tariffs, not just the three that you've seen here, and we believe that we probably have too many. And future rate cases are probably going to try to consolidate those down to give some core residential rate tariffs with meaningful differences. But the answer to your question is that customers really want the ability to choose. They want have control over their rate structure and their billing. And I'll say, maybe I don't care about saving demand and I'll pay as much as I want for energy, or I want a flat bill. And it's important to keep those customer considerations in mind, because in the end we're a business and we have customers. And if it were just my rate department, sure, I'd put the one rate on the system that makes the most sense for the company, but we have this committee back at my utility called our Energy Policy Committee, where it's all of our vice presidents sitting around talking about what we should have, including rate design. And our vice president of customer service thinks much differently than I do, when I'm talking about rates and about what our transmission and ops folk think the rate structure should be. So I think the key is to have the right mix of rates on your system that appeal to all the various stakeholders.

Question 9: So I agree with Speaker 1 that the structure that you're talking about is maybe an ideal way to be going. The one part about it that troubles me is the time of use rates. Because what most people mean by time of use rate is what you saw for Speaker 3, which is, we took on-peak and off-peak, or maybe we have three periods, and then we take an average for those things and we apply it all forward. And these are based on the idea that I can tell you what it's going to be six months from now and it's all done in advance.

But the calculations I've done for PJM say that when you compare that with where the logic takes you, where the logic takes you here is to real time pricing, not time of use rates, but actual

real time prices. And if you go all the way, the question is, how much do you give up by going to the simplified structures, the time of use beforehand versus the real time price. And the number I came up with, to my surprise, was that 80 percent is what you give up. You give up 80 percent of the economic benefit of going to real time prices by averaging down to predictable time of use prices. You only get 20 percent of the efficiency gain that you would get if you went all the way to real time prices. So why not go all the way right away, if you're going to go to all this trouble?

Speaker 1: I think that is a great question and I am pleased to report that Spain apparently agrees with you. [LAUGHTER]

I have my inquiries out in our London office. We have the former Secretary of Energy of Spain as a principal in our London office, and I'm keeping in close contact with him. I have no idea how they're going to do. I did ask him. They were measuring the impact in terms of how they are perceived. It's too early to say, but especially given the question that the EDF experts have raised, we all know that that duck curve is coming. It's not just in California. It's a global concept.

I was in Berlin two years ago talking about time of use pricing with this CPP adder that several people now have accepted as sort of a view of the future. Well, not everyone, but several have. So a person got up in the room and said, "We have negative prices in the middle of the day. Why are charts showing load peaking in the middle of the day?" And I'm sure it was about the net load in Germany. They had more of this than anyone else. Hawaii is facing a similar scenario. In those cases you need the hourly pricing even more.

And I would say the only challenge with hourly pricing, which has been there since it was first put forward, has been this issue that customers would not be able to deal with it. They don't

know what you're talking about. I was actually looking at a video of a program where I was talking about hourly pricing, and just seeing how I did, you know. We all have that hesitation after we have given a talk, and my daughter, who's a lawyer, happened to be in the room and she said, "Dad, are you talking about hourly pricing for electricity?" (I don't tell people what I do at home, right? [LAUGHTER] So, I said, "Yeah." She said, "You must be crazy," and I said, "Well, I'm sure I'm crazy even without talking about hourly pricing."

I mean, the realities become a lot easier with smart technologies. You won't every think about it. You'll have smarter apps, you'll have smart thermostat, you'll have appliances with chips in them...whether or not you want the chip to be there, it will be in there. You can always have it taken out if you want, but that makes it a lot more feasible to do for residential customers. I think for years and years that was the roadblock-that they won't understand it. Or, they'll have to get up at two in the morning. One person who was a former commissioner from another state said that he would get a divorce even if a simple time of use rate was to be put forward. So I said, "You're probably getting a divorce anyway, why are you blaming the time of use on it?" [LAUGHTER]

Speaker 4: The one thing I would add is in picking up on what Speaker 3 was saying, often these things you want to phase in. Certainly business customers are probably the place to do it first, before you move to residential. I'd be curious, with respect to your 80/20 split, how much of that is on the residential side versus how much is on the business side.

Speaker 2: An hourly pricing program has been offered in Illinois for years as an option by Ameren and Commonwealth Edison. And there's all kinds of data that they promote showing that most people, if they got on it would save money...except for last January, when the prices zoomed up because of the polar

vortex and the lack of natural gas in the wholesale markets. But putting that aside, how many people have signed up for that after years and millions of dollars of promoting that program? About 20,000 out of multiple millions of residential customers in Illinois. I mean, that's not what people want. That's as simple as I can make it. They don't want that. They're fearful of it. Maybe it's not a rational fear, but that's not the way they want to pay for basic essential electricity service. So theoretically you can do whatever you want on your spreadsheets, but it ain't gonna fly. That's all I can tell you. [LAUGHTER]

Question 10: One of the things I've been thinking about is that if you were to move to a demand charge to try to recover some of the distribution system upgrades, how does it translate in terms of sending any kind of signals eventually to the utilities to try to reduce the expansion of the distribution system? On the generation side if you have an increase in demand charges and there's therefore a reduction in demand that that would somehow flow through to reduction in the amount of capacity that has to get procured in the wholesale market, but where is this connection if we were to get folks to respond and reduce their demand that we might actually see some cost savings or some cost reductions in the cost of maintaining the distribution or providing the distribution service? Or is there a connection?

Speaker 3: Well, I would say the incentive for that is the ability to recover the cost of those before looking for investments in a rate case, because if we don't need it and we can't prove that we need it with the demand charge we've been given it will be hard for our regulators to say we should be given cost recovery of it.

Questioner: Are you building any of that into your planning right now? I mean, are you looking at this and saying, "Well, if we have a demand charge then we would have a reduction

in the need for capacity in our distribution system”?

Speaker 3: Absolutely.

Questioner: I think this is one of the issues on the flip side with distributed generation. I mean, one of the things you hear anyways is that if you start to have a more distributed network perhaps we're not going to need as much in our T and D system. You know, eventually that there may be changes in what's necessary there. It seems that there's an underlying assumption that the costs of the distribution network are going to continue to go up, but the demand is going to potentially level off or the usage is leveling off, for one of your charts.

I'm just trying to understand how this could actually have an economic impact to hopefully make our distribution system more efficient, if folks' demand and usage became more efficient based on a change in the rate design.

Speaker 3: So I actually think the opposite is true with respect to what you said on the distributed generation. With the increased penetration of distributed generation, you actually need to make smart grid investments that allow the grid to operate in a way that doesn't upset the regular mechanics of the system. So that actually does require system upgrades.

Speaker 1: I guess to the extent that you can quantify the savings in load due to having a better load factor and having lower demand, then you factor that into any new resource planning as you look forward at the grid. It may take years for some of that to be realized, because the grid was invested in 10, 20, 30 years ago and it's not going to suddenly disappear. But at least it opens the door towards not expanding the grid just because load factors are getting worse and you have to keep some grid capacity in reserve to meet that load. Ultimately I think

you do need demand charges. Maybe you need more than one.

Speaker 3: What a demand charge actually does is encourage the development of something like battery storage, and that's what we're thinking about. That's something that actually will reduce demand, so we look at it much less as an opportunity to, you know, gold plate our distribution system and therefore recover higher demand costs as, this will actually incent the development of behind the meter technologies that could ultimately lower demand. And so we ask, what is our modeling going to have to look like to make sure we have the cost recovery we need in the short term to pick up historic fixed investments? It's beyond just looking at the utility's focus on what more do we add to our system, but it's a question of, how is this going to change the energy infrastructure in a way that we need to then model on the utility side?

Speaker 4: I would just add I think you hit one of the keys, which is planning. Most utilities, they do these distribution plans typically four years in advance. They usually have to bring it before a commission for approval, and the commissioners need to say, "Is this really needed?" The rates affect this, but there're lots of other options, too. Whether it's more storage, more DG, more efficiency, there're lots of things to look at and see what is the least cost solution for the repairs. A demand charge is just one of multiple tools that can be employed. We shouldn't rely on it strictly.

Speaker 1: Anyway if you buy one of those fancy Teslas, you have to recognize that imposes costs on the grid that cannot be recovered just through the energy charge. So as more of these new technologies come in where there's battery storage on one hand or big electric cost on the other hand, demand charges, I think, apart from improving efficiency, are more equitable, in terms of saying, "OK, you have the big mansion, you have the big air conditioner, you have the electric car..." whereas there are others who

don't, and the cost in cents per kilowatt hour today doesn't reflect the variation. There is no incentive for that other consumer to think about demand when they're making those big purchases or running them simultaneously. I think most of what Speaker 3 talked about was how they're able to stagger the use of their appliances today and modulate their demand without compromising on comfort.

Question 11: I've got a disconnect in this whole discussion, and it has to do with the retail choice states. How does a utility doing its retail rate making set a demand charge for customers who may not be purchasing from that utility and may be getting all their supply from a competitive supplier? And, even more importantly, can a customer just avoid the utility's demand charges by buying from somebody else?

Speaker 1: So, the purpose of the demand charge is not to change their choice of retail supplier or to get into energy purchase decisions. Those are totally independent of the cost of the grid. Let's assume we're talking about somewhere like Australia or Texas, where the utility just has the distribution network. All you're talking about is why should that cost structure off that network, which is fixed, inherently, be captured through a volumetric charge? Right now we have that confounding problem, so it's partly just untangling the confounding problem, unpacking it, if you will.

So by and large it is the grid cost with distribution and transmission. In the example I had, I included a small amount of generation, because some generation capacity is being kept on reserve for that unexpected moment in time when you'll have the peak load. And so, again, it's something you can do with the cost of service study. There's a really good report on the integrated grid which takes a typical customer's bill of, like, \$110.00, and they're saying that \$51.00 of that is fixed cost and they break it up into distribution, transmission and generation (and there is a small slice for generation in there

as well). I'm not saying it's a definitive work; it was just a cartoon that I put up there. It's a conceptual analysis. You need a cost of service study to justify those slices in the pie.

Speaker 2: Of course, in restructuring states you would not be able to include any generation supply costs in distribution rates, right?

Comment: I think that if the utility is carrying capacity in reserve to meet emergency situations that --

Speaker 2: The utilities don't carry capacity in restructuring states. They purchase default service, which includes electricity, any generation product that's needed, capacity, energy and ancillary, whatever. It's all in there.

Question 12: I just wanted to circle back on some of the earlier comments about what happens if you include operations in all of this, because we're doing some work in California. Yes, we have the static planning study and it's sort of like, "Red, yellow, green, put stuff here..." But you can do so much more. And so I just wanted to speak to that, because we're doing some work with flexible loads, micro grids, things that will take a solar cloud cover signal and match it with a feeder health signal and an energy price and say, yes, we can do so much more. It requires transparency. It requires identifying these products and services called flexible capabilities.

I'm a little concerned, when I think about what I've heard here, that what I would call a basic rate is too complicated, because it's even hard to get it to industrial customers and large commercial customers? So what does it take to effectuate this at a residential level? That is, to effectuate having customers use their loads, essentially their consumption, in a way that can fill the belly of the duck. So that it can shave those shoulders off of whatever you want to call it, the duck curve?

There's a lot that can be done, right? Customers have choices about what to use. I'm assuming we're going to have smarter appliances, and yet what I'm hearing is that even what we have today might be too complicated for residential customers to use, but if you can have flexible operations you can do so much more with renewable energy in the stack. You can improve the efficiency. How do we couple those things?

Speaker 1: This is the question that actually a lot of people who are in the demand response base are looking at very closely. It's sort of the next frontier for demand response--how to make demand price responsive and also responsive to operational considerations, including the integration of renewables. Pilots are being done in the Northwest and Hawaii, for example, with electric water heating, which has high saturations in the Northwest, to see if the water heater charging can be modulated, ramped up or down depending on what the operational constraints are. New smart water heaters are being developed that automatically allow that behavior to occur, in addition to the HVAC kinds of device like the Nest thermostat. I don't think there's any good data today that you can use for prediction purposes. It's a very new idea, and we need more demonstration projects to prove that customer demand actually can in real time move that fast.

Speaker 4: I think the issue of how you decrease the head of the duck is going to be a key one. And there's going to be a variety of tools. I think that as Speaker 3 pointed out, we'll see more storage. I think there's going to be more automatic controls, whether the Nest, or your refrigerator talks to the grid, or whatever is set and forget. We're going to see a lot more of that. I think there will also be more targeted energy efficiency, just like we used to do a lot. Targeted air conditioners. I suspect that in the future we will need to do more targeted at the evening peak.

Session Two.

Hidden Values: Missing Markets and Electricity Policy

Incomplete or imperfect markets can produce imperfect reflections of the underlying value of energy services and technologies. The problem is severe enough in the context of working wholesale markets. The issues could become even more significant with the influx of distributed energy resources and greater emphasis on markets in distribution systems. The values may be hidden because of inadequate pricing models (e.g., poor scarcity pricing), missing products (e.g., ancillary services), or fundamental technological implications (e.g., lumpy investment decisions). In some cases, the so-called missing values are really just transfers from one group to another and are more coveted than missing. The policy implications are different depending on the diagnosis. How can we define and estimate the so-called hidden values? Where is the replacement for market discipline to avoid paying for benefits that are less real than imagined? How can markets be changed or pricing reformed to make the values transparent? What are the policy implications for dealing with the hidden values that cannot be made transparent through market redesign?

Speaker 1.

Thank you. So, I don't speak on behalf of anybody I've ever met, [LAUGHTER] and I'm now going to talk about this issue of hidden values. And this graphic which you should have in front of you is one of many that I possibly could have used, but it's just illustrative. It comes from a Sandia report. In this case, they were talking about storage, and they identified all these different values that could be captured, the benefit that could be captured from storage in different ways. One of the things I like about this graphic is that it also tried to characterize the maximum market potential, which you don't often see for a lot of these things. Something might look like it's highly valuable, but there could be only three megawatts' worth of market potential for doing it, and so, is it really worth much of a conversation about the policy?

The implication of a lot of these studies, and you see this across the board, is that there are all these different values that we don't ordinarily talk about and that they are obscure or we're prevented from capturing them, and most often people are looking for ways to argue that we should somehow recognize those values. That's the first step. And then the second step is that we

should compensate people for providing those values. So we should give them money to pay for the services that they are providing. And these claims are usually made in arguments that are about "out of market" benefits, so somebody has to collect the money from somebody else and make them pay for this hidden value that otherwise we wouldn't be able to capture. And the question that I'm trying to address in this presentation is, to what extent is this true, and what are the implications for policy?

What I'm going to do is to walk through a story, but let me tell you where the endpoint of the story is—it is, could it be that there are things that are hidden values that we somehow want to address and recognize? And the answer is yes. And then the question is, what are the things which cause these? And the answer will be that most of the time it has to do with other policies that we've adopted, which are obscuring what's going on, and if we could somehow deal with the other policies, then this problem would tend to go away. The number of things which are inherently a problem and require some kind of special intervention are actually, I think, on a large scale, relatively rare, and the policy implications for how you deal with those things are not always what people would often claim.

So what I'm going to do is discuss how to think about that problem, and I'm going to outline, but not go through exhaustively, the sort of textbook story about complete market theory and why market values and market clearing prices should be the first thing that we're trying to fix and get right. And what I've drawn here is the standard story from the textbooks about supply and demand, and we have consumer surplus, which is in the top colored area, and producer surplus, which is in the bottom colored area, and equilibrium prices, and the marginal prices in the market support the efficient solution.

And in arguing about economic efficiency and supply and demand and market clearing prices, we don't point out that, given the great theory of the invisible hand, it's not necessary to calculate all those colored areas and talk about all the things that would have happened if we had done something else, and had been at a completely different solution. It doesn't matter what the shape of the demand curve is above the equilibrium point, and it doesn't matter what the shape of the supply curve is below the equilibrium. Probably you don't have to do that calculation. And if we change the conditions and make more supply available, we get shifts in what the prices will be and there's redistribution between consumers and producers. That's all true, but it's also not relevant to what the equilibrium price is. It's the marginal price determined by the supply and demand in this sort of textbook analysis.

And a lot of this discussion you see on hidden values is, I think, confusing some of these ideas. So they say, "I should be paid for the surplus that the consumers are getting benefits from, because I change the prices and availability," or, "I should be paid for reducing the infra-marginal costs associated with generation." But I think that's actually wrong, if you're looking at this from the point of view of just standard efficiency. There's nothing new in this picture. This is just the standard story that we all see from the textbook case. And I'm going to look

in a moment at what happens when you start changing those assumptions.

The second graphic here is similar. I just took another case which was storage and said, do we encounter essentially the same logic and the same argument in the case of storage? And the answer is yes. You essentially get the same logic and the same argument in this case. What I did was postulate a supply curve in this sort of standard way, and then two different periods, one with low demand and one with high demand. So low demand is D1 and high demand is D2. And in the low demand period, you store. And in high demand period, you discharge from storage. And then, when you're storing, you raise the energy price in that market and you reduce the demand and you increase the supply. And when you're discharging, you lower the price, and therefore the regular supply for that period and you just take energy out of storage and then you can satisfy more demand and the prices adjust. And you get these little triangles at the top, related to changes in price, and supply and demand that seem to be like they might be relevant, but the answer is that it's just like the consumer producer surplus. Those things are not relevant. What's relevant is the difference between the price in the second period and the price in the first period after you do the storage. And if you take the price differential, that's the marginal value of the storage. There's nothing hidden. And all the other movements of triangles and prices is just analogous to the problem of well, if I change the supply and demand conditions, I will have a redistribution between different periods and different consumers and so on, but it doesn't change the marginal arguments about incentives and what we should be doing in market design.

So in the storage case, a lot of this should be taken care of and we don't have to worry about it. We can just observe what the prices are in the marketplace and there's nothing hidden, if we get the prices right.

The next example is something I've used before, but I'm just regurgitating it here, which is to take the case of transmission and apply the same argument there. And as you recall, in order to simplify that for the discussion we had about this in the past about cost allocation, I imagined we had two different regions, an export region and an import region, and supply and demand in each. And then you net it all out. And you get a picture, which is in the middle, which is the net exports and the net imports, but it turns out it's amenable to the same kind of analysis, and if you blow that picture up in the center and you look at it, there are all these different categories, which will often come up in the conversation about hidden benefits, which are the surplus before, and the surplus after, and how that changes what producers pay, and the changes to what consumer pay, and the changes with what happens to congestion rights, and all the other kinds of things that happen when you expand the transmission capacity.

But if you take the textbook example here and you look at this picture, and it's that vertical red line there that matters (showing how increasing transmission capacity helps you move closer to what would be the equilibrium in the absence of transmission constraints). And the difference between the price of exports and the price of imports, that's a congestion cost differential, and if you make a marginal change in the transmission capacity, that would be perfectly compensated by the value of the financial transmission right that would be accommodated at that congestion rental. So for small changes in this simplified textbook world, the market price produced by congestion compensates for the investment in the transmission, and there's no hidden value. And all the other things that we're looking at there, all these different transfers back and forth, they happen, but they're not part of the economic efficiency story, and therefore you don't have to compensate people for those things in order to get the efficiency.

So for the textbook examples for storage and transmission, the answer is that there are no hidden values, and this is just a problem of getting the prices right. And as we know from our discussion many times in the past, the examples I used so far are one period, but you could apply exactly the same argument to multiple periods where you have low and high demand, and you get different market clearing prices. This is a familiar picture that we've looked many times before.

And then, finally, you come to the case of locational marginal pricing and the bid-based, security constrained economic dispatch framework that we've talked about. And if you go back to look at the book by Fred Schweppe and his colleagues back in 1988, when they explained all of this, basically what they said is that everything I just said for the first three of several graphics applies when you have an actual transmission grid. You do the integrated story, and you've got LMP and all the other kinds of things... So there's no hidden values there.

So what's the problem here and why do we have this conversation? And why do we have these lists of the types of hidden values people think apply? The answer, I believe, is that, not surprisingly, this has to come from some analysis about incomplete or missing markets. So if you have the textbook example of markets that I've used so far, the problem goes away. It just isn't there, if you get the prices right and you have these well-defined markets.

So there might be a problem where you have incomplete and/or missing markets, and that's certainly true. And the question then is what does that mean? And the answer, in part, is that what you should do about this depends on the diagnosis of what the problem is. So, it's not just that, "There's a missing market, therefore, give me the money," which is the usual argument that you see. And the answer is "Well, wait a minute, what's the problem?"

An example of a missing market would be, well, the Southeast, where there's a policy not to have a market. So you don't have a market in the Southeast. You don't have organized markets, you don't have RTOs. So the policy implication there is, well, if you want to address this and find the hidden values, have a market, and that would be a big help. And if you're not going to do it, that's a different conversation and then we can go down and look at that.

Another category would be avoidable market design flaws, and I'm going to talk quite a bit about that, because that's obviously a big problem. But where I'm heading for with that, of course, is, "Fix them!" Avoid the avoidable market design flaws. These are things that are fixable.

There's the problem of imperfect market implementation. This comes up in the RTOs--can we actually do real perfect economic dispatch? Well, the answer is no. So it's going to be imperfect, and there are going to be approximations built into it and a few things that they have to do. But I'm going to argue that although that's ubiquitous, it isn't very important. Because it's just small beans. And so we'll do what we have to do. We'll have an imperfect implementation, but it'll be as good as we can get it. And then, the costs associated with that are not really hidden values that could be solved any other way. They're just something that's kind of an overhead we have to live with.

And then there are market failures, which I'm distinguishing from avoidable market design flaws. There are some situations which are fundamental characteristics of the technology, and then some which are correctable market externalities like the carbon problem.

So the prescription is that the policy response should reflect the diagnosis. The first thing is market reform. The second is more complicated, which is the hybrid market design, which is,

how do you design these interventions in the places where you do have a problem so that it's compatible with the rest of the market, as opposed to saying, "There's a hidden value and give me the money." There's something in between that you could do. And then, eventually, there's the monetization of these hidden values.

So how are we doing on the reform story? Well, you're all familiar with this. I won't dwell on it. The map shows you we haven't extended the markets to the whole country, so that's an issue. I'm not going to talk much about that. There has been this reform process that's been going on that we all know about. The latest focus of activity has been out West with the Energy Imbalance Market and expanded markets there. And the statistic which I hear bandied about now is that we now cover more than 70% of the United States electricity consumers. But there are plenty of examples of problems--market defects, scarcity pricing, extended LMP and retail rate design are all issues that raise this problem. In talking about market failure examples, I'm going to emphasize the transmission investment problem and then, of course, climate change policy for dealing with externalities.

So, where do we stand? Well, let's take one of the problems with the analysis that I presented so far, which is simplified on purpose. So, we were selling energy. So, you produce energy and you consume energy, and so forth. But we all know that in these electricity systems, we have a lot of other things and services that have to be provided, like operating reserves. And they go under the heading of "ancillary services." What this includes depends on how long your list is and which things you want to break out, but the most important ones are clearly operating reserves and voltage support, frequency regulation, black start, and so forth. Now, these are actually important services. They have value. And various kinds of generation and load can help provide these services. And the trick here, I

think, is basically to design policy so that those values can be made transparent and revealed, rather keeping them hidden. And I'll focus on the operating reserves, just because of the experience in Texas I can point to. Voltage support I've written about. There's a reference here. You can talk about how to price that better. Frequency regulation is an area where I think we do have markets for frequency regulation that are somewhat specialized. I'm not going to talk about them mostly because they have the characteristic of being inherently small. So it just can't be a big deal. And black start is like that as well.

So, what about operating reserves? Well, we spent a lot of time wrestling with this in this country. I've been involved in this conversation for a long time. We now have the implementation in Texas, in ERCOT, of a market for operating reserves in short run periods of time. This is a nested model that they actually have of synchronized and other kinds of reserves, and they interact with each other, and help set prices. The prices then work into the energy market, and this provides a natural way to incorporate the logic of scarcity pricing in these energy markets, and the implementation in Texas demonstrates that it's feasible. It's certainly doable. All it takes is courageous regulators, and we have courageous regulators in Texas. And it does wonderful things for your state once you do it. Like the first thing that happened was the weather got better. [LAUGHTER] So, I recommend it, and it's a very successful model. But it's an example of what I mean by saying, "Fix the market design."

The next issue I'll look at is this question about transmission cost allocation, and we have this complicated story that's still unfolding under Order 1000 that the Federal Energy Regulatory Commission adopted. In that graphic that I looked at before about transmission, remember, I was talking about a very small change in the amount of transmission that you were offering, a very small continuous investment, when I said

that in that case there's no hidden value and you didn't have to worry about it. This is the case that Schweppe analyzed, and so on. But the reality is that transmission investments tend to be lumpy. And so they come in large steps. So that's why the pictures show this big change in transmission capacity. And then you have to worry about all these little other areas there on the chart that change when you decrease the transmission constraint—the increase in the consumer surplus, and the increase in the producer surplus, and the reallocation of congestion rents, and all these other kinds of beneficiary calculations. So, in that sense, there are a lot of hidden values that you wouldn't see otherwise. These are not things you can observe in the marketplace. These are all computations that are done from models, and ,therefore, inherently depend upon all the assumptions that go into the model. But I think it's an unavoidable fact that these hidden values exist, but it's a fact which is driven by the lumpiness problem.

The policy conclusion that I come to, which I'll summarize, is that these hidden values, or estimated values, or other values that aren't going to be measured in the marketplace should be considered when you're making the decision about the transmission investment. So you should think about that and all the other alternatives, and all those kinds of things. And then you should either make the investment or not, but these same calculations should not be considered when you're thinking about the things that compete with transmission, if they are not also lumpy. In other words, if they're continuous and small, then the policy implication is that they should live with the market price that it results. So it's not that the hidden values create money that should then be used to pay somebody else to provide something that substitutes for the transmission. It's inherent in analyzing whether or not to go forward with the transmission, but not in the pricing for alternatives that come into that system. So, hidden values are these other kinds of values

that are not observed in the marketplace and they are relevant for the decision because of the lumpiness of transmission, but they're not relevant for the decisions on investments in the other areas.

The next example is environmental externalities. That's another thing that everybody knows. That's a market failure problem. And the policy implication is completely straightforward, which is, tax carbon. OK, so we know how to do that, conceptually. The picture on the left is the graph that comes from the interagency study about the social value of carbon. It shows you there's a lot of uncertainty. That's true. But it doesn't change the fact that once you settle on a number that you take as the policy representation, say, \$30 a ton of carbon, the policy is to charge that to everything across the board, and you'd have the same price everywhere in the country. It's uncertain, but that's life. But it doesn't mean that you go around and you charge different values to everybody in every kind of different context.

We are very far away from that policy, although I saw in the *Wall Street Journal* this morning that Senator Schumer came out for a carbon tax yesterday, so maybe there's hope that we will in the future adopt this. It's certainly becoming much more fashionable to talk about this in Washington. But the reality that we're all in this room going to be grappling with soon is whatever gets into the final version of the Clean Power Plan. The map on the right, which I became aware of recently, of EPA's estimated Marginal Abatement Cost in 2013 under the CPP by state, was put together by Michael Wara at Stanford Law School. The numbers are actually EPA's numbers. So this is what EPA presents in their model simulations as the shadow price for the carbon constraints in each one of these states. And if we were following the best policy, the numbers would be the same across the country, and the numbers would be in the order, probably, of \$30 a megawatt hour. And you can read for yourself that the range is

from \$0 for California (how they got that number I have no idea) to \$101 per ton of carbon for West Virginia. So we are very far away from having a sensible design. A design principle, however, is pretty straightforward, which is that we should have a common carbon price.

We have similar arguments that are associated with treatment of the demand side. I'm not going to go through this one because we spent the morning talking about this and how to structure rates on the demand side, but an awful lot of the problems that we have where people are going around talking about these hidden values that have to be monetized and paid to people derive from the failures of the retail rate design in terms of not representing the actual cost of the system, and they were trying to undo one design with another. But I think that was pretty well covered this morning.

So where should we be going with prices and these hidden values? Well, get the prices right. Not surprisingly, that's where I come out. That doesn't mean that it solves all of the problems, but it does mean that most of the problems actually can be addressed by that, I would argue. And then, for the remainder, we want to design these hybrid markets, like the transmission cost allocation story, which are compatible with the textbook design to the best extent that is possible, and we can't go further than what's possible. But then, for the remainder, we have to deal with it some way, like through an uplift calculation, and we want to minimize the distortions in the marketplace. And whether or not this is important, you heard today, this morning, the discussion about the effects of net metering and what started out as a small little subsidy, which is now growing and growing.

This quote about subsidies comes from a National Academy of Sciences study that was from Bill Nordhaus, who was the chair of that study. And he goes through the problem of trying to subsidize in one area to compensate for

the subsidies in another. And we're subsidizing and subsidizing on top of it, and what we're doing is we're adding and adding costs to the system. And then, the bottom line, in terms of the environmental impact at the bottom of the long paragraph. He says the net effect of all the subsidies, taken together, was effectively zero. So if we don't get good market design, we're probably not going to get good broader environmental policy. So, in the end, it's much more effective to penalize carbon emissions than to subsidize everything else. Thank you.

Question: At the very end of your presentation, I think you said that getting the prices right will solve most but not all of the issues. So, is there a set of issues that would not be solved by getting the prices right? And what would those be?

Speaker 1: Well, broadly speaking, it would be something that deviates from the textbook example I presented as sort of a benchmark. So there would be something in the assumptions of the textbook example that is not true. In the case of transmission expansion that is lumpiness, where it comes in a large step, and then everything changes in a "but for" world. The textbook example assumes everything's continuous. There are no big steps. And you can make continuous investments up to the last step, and then you stop, and the marginal value and marginal benefit balance. The same thing is held true when you're dealing with startup costs and dispatch and operations. That's another lumpy, it's on or it's not, kind of thing. So those kinds of situations, I think, are inherent in the technology, and the sort of standard market arguments about market prices supporting the best solution don't apply in those cases. The rest of it is things like carbon externalities. That's pretty straightforward, but we know how to deal with that in principle.

Question: This morning you challenged the panel by saying that you'd done a welfare study that suggested that TOU pricing gets 30% or 20% of the welfare benefits of RTP, which you

set as a standard. So, what's good for goose is good for the gander. Have you done a welfare study to establish what a market that achieves all the goals you want would achieve, so we know what we're giving up when we back away from it?

Speaker 1: Well, if the standard is to what I described this morning, the answer is yes, because the standard I described this morning was a simple back of the envelope calculation. And I think there have been a lot of studies about the benefits associated with markets in the electricity sector and trying to improve upon those markets. We don't have a comprehensive situation to study, because the places where we have the equivalent of experimental design are all limited to special cases. But if you add up all of those special cases, you get pretty substantial benefits associated with it.

Question: If you go back to slide 12, where you're showing what the gold standard is and you talk about "beneficiary pays," is your idea of "beneficiary pays" cost allocation to both generation and load, since, clearly, from slide 12, it shows that you've got surplus going both to producers and consumers?

Speaker 1: Yes.

Speaker 2.

Thank you very much. A couple caveats before I begin. First, my comments today will largely represent my opinion, not necessarily that of my company, even though I stole a couple slides from them that I would like to talk through. And my second caveat is that even if everyone in this room agrees 100% with my view, unlike Texas, I won't promise that California's weather changes and we get some rain this year. So, with that said...

There are so many dimensions of hidden value. What's been taking a lot of our attention back in the shop is the distribution system. We have the

New York REV going on, and inside of California, we have the Distribution Resource Plan, the DRP, that is actively underway. So this talk is going to really focus on the hidden values within the distribution system.

As a starting point, I believe there is hidden value. There's also some not so hidden value in this system. We're looking for some flavor of policy that lets us extract this value. I think the big picture is, how can we see customers realize the value that's hidden in there? How can we unlock it? And in unlocking it, how can we make sure that the end use customers are realizing this, and it's not just being transferred to new participants that are otherwise capturing what could be providing real online value to the customers in the grid?

There are a couple of themes I'll get into. Some value is already identified, and it's transparent, and it's available. And where we have that transparency we should be using it. We should be designing systems that allow that to be incorporated and captured. Other values are not as transparent. There's the transmission example that was talked about. But we should be looking for ways to making that transparent. It's my view that we should be using market forces where we can to let the market tell us where the value is and how we can capture that, rather than really administrative-type approaches of, "There's missing value, so pay me." I agree with that. And market values should be driving it. And we're going to need some new solutions as we get into the distribution reliability aspects related to distributed energy resources.

With that said, I'll argue that there's a foundational difference between what's going on in the distribution system and how prices are likely to form and work, relative to what's happening on the wholesale transmission system and the price formation we're seeing in the ISOs. So let's identify this value and let's see how much we can capture for our customers. That's the big theme here.

Southern California Edison's general approach, in terms of distribution resources, is that we need to transform the way we're planning our distribution system, from the traditional ways of forecasting build out and the common assumptions on the technology that you use, to a more dynamic approach in terms of seeing what the options are and the best way to move forward in light of technology. This is going to require a new way of running the grid, eventually, too, with new tools and technology, and data sharing. Information's going to be a huge part of recognizing value, both the exchange of information and understanding and the reaction to information. And as some of the other speakers have mentioned, we see that there's investment involved in getting the distribution to be sort of the grid of the 21st century, and to have the information infrastructure as part of the electrical delivery infrastructure.

All of this has got to be done in the context of safety. We are moving into a newer world. We had some instances, like with Hurricane Sandy, as I recall, with people with solar panels on the roofs and people expecting that those people would have power in their houses when everyone else was out. But, for safety reasons, they didn't. There were concerns about power flowing into the grid. The electrical crews have to work safely in this environment. So it is a real issue. It's very much at the top of our company's mind. As we start moving these distributed technologies and interacting with them, how are we going to address safety issues and make sure that not only do we have an efficient system, but a safe system?

"Reliability" and "resiliency." These are themes that you're hearing over and over. There are promises that moving to more distributed resources are actually going to make a better, more resilient grid.

And this slide shows sort of a vision of many more distributed resources throughout the distribution grid. And the big concept is that's it's no longer a one-way power flow. It's not just power from the big, remote stations flowing all the way through wire systems into the houses, but, rather, we're having two-way flows on the distribution grid, where not only are some locations not drawing power off of the grid, but portions of the distribution may be feeding other portions of the distribution, and, ultimately, you may have portions of the distribution system feeding into the wholesale network. So this is a new concept. A lot of maps and monitoring, control devices, and dynamic control are expected to be needed to make this two-way grid work. So we've got big ideas, but where's the value? How is this a good deal? Why are we pursuing this?

So, first, let's talk about what I think is the easy part of the problem, the transparent value. And where we have transparent value, we need to use it. And where we have non-transparent value, we need to discover it. So the easy part in my mind is distributed resource dispatch. And this links largely into the discussion earlier this morning. In organized markets, at least, where we have that market, we know what power's worth at any given time, at any given location, relative to the wholesale market. It's there for the taking, and it's actually, as we were talking about, the right price. If the market is designed right, it's actually revealing what the value of this power is. There isn't really a need to reinvent the wheel. It's there. We should be using it. So what this is arguing for is that these distributed resources, the ones that have the ability sell into the grid, or to store and resell into the grid, if their main goal in life is to participate in the energy markets, we should be using transparent prices if we have them. That argues for flavors of real time pricing based on wholesale LMPs, where they're available.

Now, there may be difficulties in doing that. We talked about the consumer engagement that's

necessary to do this. I believe that automation, as others were talking about, will help make this simpler. But there are policy issues. It is a big change. At a minimum, and I know this can be considered a four-letter word, TOU rates, at least if they're aligned directionally with what's happening with the temporal spot prices, that's an improvement. People should be selling when prices are high and buying when prices are low. It's not all that crucial that they get exactly the right buy and sell price signals, as long as we're getting the directional signals—at least using some flavor of TOU rates to utilize and optimize these resources that are in the distribution system.

Now, there's another large source of hidden value, and quantifying this one becomes much more difficult. And this gets to the concept of distribution deferral. Can we avoid building a large line, and, instead, use distributed resources to delay that investment? This gets very tricky. This is a modeling exercise. There really isn't a known price. There's a whole host of assumptions go into this. In California, they've actually dictated a large laundry list of things that we're supposed to be looking at in this. It's a framework to start with. If we get into it a little later, I can pull up my notes and talk more about it. But it really is a modeling exercise on deferral costs.

The concern I have here is that we really don't know what this deferral value is. We may know something. For example, that certain areas of the grid are robust. There is plenty of capacity. It's built to be very robust, and we can accept lots of distributed resources, and they're really not going to do anything for deferral value. On other parts of the grid, it may be more apparent that you're in need of some sort of action. So, directionally, you may say that there are red zones, green zones, yellow zones.

But once we've identified areas where we think there's a potential for these alternatives to provide value, how are we going to reward those

parties providing that value? What I'm very concerned about is some sort of modeling exercise that says, "The marginal value of whatever in this grid is so many hundred dollars per kilowatt year of capacity," and then that everyone who shows up at the door says, "Give me my hundred dollars per kilowatt year for capacity, because I built something." Well, that wasn't discovering what the value was. That was some sort of arbitrary transfer based on some modeling assumptions. What we'd really like to do is discover the values.

So, yes, we have a red zone. We see that there's an area that might benefit. Have the utility sketch out what it thinks its costs are, and then have some flavor of competition for alternatives. Let others present their prices, present their options, ask what they would demand to be paid to provide some of this service. Let them reveal what they can do, rather than write checks without market forces sort of driving to more efficient outcomes. And that's what I mean by "discovering" it. Through this process, you'll start to see discovery of what the market can provide, rather than just an administrative transfer.

So when we don't have this transparency, let's discover it, let's be smart about this, and let's try to set up ways that don't simply say "Well, the utility said the value was \$100 per kilowatt year. So, we will now pay you \$100 a kilowatt year, and the customer will receive zero benefit from that transaction." Where was the value to the customer? There may be value to the third party who gets a big check, but where was the value to the customers? Let's discover the value, and let's make sure the customers are capturing a large portion. I mean the person willing to do that is still capturing value, or they wouldn't be willing to do it.

My next big theme has to do with the fact that the distribution system isn't just a lower voltage transmission grid. It's playing a different role, and the reliability aspects and dimensions that

we're seeing are different than what we're used to in the ISO wholesale markets. And there are lots of radial type of systems in the distribution, where there's only one subset of parties that can solve any reliability problems. We don't have this network where you can get electricity five different ways. We're going to have price signals that may, if you're using price signals, be counterintuitive, where the wholesale grid may be perfectly happy to accept power, but a local region may be very constrained in the distribution system. So, at some times, the wholesale price is not going to reflect the distribution reliability issues. We need to address the radial nature, the risk of market failure from very limited supplies, the unique problems that are being seen on the distribution grid.

And I think there's a tendency for people to think, "We know how to do this on the transmission system, let's just do more of it. Let's just push LMP down to the blender level. Don't stop at the house, go down to the device. That's the solution." And my view is that we're not there. That's not the right way to approach this problem. The reliability responsibilities of the transmission folks versus the distribution folks are different. They have different tasks to attend to, different jurisdictions. The nature of the grid being networked in the T and more radial in the D changes the way price formation's going to happen, or the ability to get robust price formation. We have non-congestion issues that are causing reliability issues in the distribution grid that can be solved with strange things like circuit rerouting and circuit switching that we don't see in the transmission grid, and a lot of sort of local voltage and other unique distribution issues.

And, finally, we just have a pure numbers problem. The distribution circuit count dwarf the amount of transmission circuits, usually by several orders of magnitude, and the computational challenge of saying, "Well, we're able to solve simultaneously at both the

megawatt (transmission) and the kilowatt (distribution) level,” we just think is infeasible. This calls out for really a bifurcation of how some of these very minute prices are going to be applied and sent, not just pushing LMPs all the way down to the households.

And this slide is just another conceptual way of seeing the distribution market concept problem. This graph is showing, on the Y axis, well, how much benefit do we think we can extract? How much value do we think we can extract through optimization? And on the right-hand side or the X axis, the cost of implementation, using different market approaches to the distribution grid. And we’re seeing the benefits we think we can get from each form of optimization, versus the cost of implementation and the complexity on the X axis.

And we’re starting in the bottom quadrant where we’re using very simple fixed retail tariffs. Maybe you’ve got some tierings. They’re not really getting you very efficient use of the distribution assets. We think you can modify that to something like a time of use rate and get more value out of it without much cost to the system. And then, we think we can go further by passing through real time prices to these distributed resources.

And then, in those instances where we have local reliability issues, maybe there is sort of an informed administrative way of dealing with the local reliability on the distribution level. And then the last step is to say, “Let’s go all the way, let’s squeeze out that last hair of efficiency by coming up with a full optimization or a DLMP market.”

We may evolve to that last implementation method, but I’m not convinced that we’re at that state of robustness. There’s nothing that stops you from making incremental improvements and taking steps along this path when it feels like the cost benefits are there for your customers.

This last slide just recaps the reliability issues. What are you going to do about distribution reliability? Within your distributed grid you have got supply and demand, active and passive devices--how are you going to deal with it? The most complex, and I think the most theoretically pure argument is for a distribution LMP that takes into account all of these sort of issues that you’re needing to control in pricing all of them. But, again, I’ll question how much real incremental benefit there is in that, relative to some of the steps just below that. And if you do that you’re going to have to deal with the market failures that I’m relatively certain will happen on this micro level, and you’re going to need administrative backstops, regardless. And then there’s the difficult issue of synchronizing the distribution LMPs to the wholesale LMPs. That’s a big challenge.

So if you’re not going to go all the way to full optimization, how are you going to solve this reliability problem within these devices? Command and control via some flavor of administrative terms? We have analogies with RMR (reliability must-run) contracts, where there were units that were built there for specific reliability reasons. They were agreed to upfront. They may have gone through a competitive process to see who would have the ability to win that sort of contract. But then, they’re really taken all largely from the spot markets, and they are more of a command and control reliability resource. It’s not optimal. But it may be, at different stages of development, a reasonably efficient way of going.

And then, the question is well, can we have hybrids of these approaches? Are there times when access to the wholesale price is the appropriate controlling signal, and we should let these distributed resources just react to the prices in the market, and are there times when no, no, no, there’s a special issue so that they must be command and controlled? Is there a hybrid available, where we’ll let you use the prices, but, when necessary, we’re going to command and

control? And I'm leaning personally to thinking the hybrid structure is a pretty good way to get started as we start evolving the distribution system.

So, in summary, there are values in our grid. We see it. We'd like to extract this value. There are values that are available to the customers. We'd like to get that value down to our customers. And with respect to the distribution system, which I've focused on in this presentation, there really are sort of three flavors of value that I see.

We have the selection process for alternative infrastructure. There may be cheaper ways of doing it, and we should pursue the cheaper ways and let the customers get the value of those cheaper ways. But I'd like to use markets to reveal what that value is.

When we have resources in the distribution grid that can participate in the wholesale market, we should allow them, and we should be using the wholesale market to price and control their actions.

And when we get into distribution reliability, the very narrow reliability issues, the micro reliability issues, that's an area where it's less clear to me how we reveal and capture the value there.

All in all, where we can, we should try to leverage the existing transparent prices we have, the LMPs, but we need to recognize that's only part of the solution. The infrastructure market may be informed by LMPs and may be informed by local reliability issues, but infrastructure market decisions should use market forces that are sort of outside of the spot LMPs. And we do have to find administrative or some other flavor of tools to ensure we maintain distribution reliability without wealth transfers. So, thank you.

Question: One or two slides back, you talked about regulatory backup for likely market

failures. What's a likely market failure, other than bad design?

Speaker 2: Well, let's say that the distribution planner identified a weak spot in its grid, and that it really needed to take some action. Say there was a line that it knew was going to be overloaded unless some action was taken. And let's just say that through a competitive process, a battery operator came and said "Hey, I can provide a battery, because, look, I'll charge when prices are low, and when that line starts getting overloaded, I'll discharge." OK, fair enough. Well, how can we rely on pure market forces or pure market pricing for that battery? At the time when we very much need him, that battery is sort of the sole or pivotal solution. If we just say we'll let the market price this, then he has extreme market power and he can extract extreme rents in that situation. So there needs to be some sort of control in that situation to prevent that type of market failure.

Question: Did I just hear what I wanted to hear? Or did you say that paying for avoided costs is a transfer, and therefore should not count as a payment or a value that anybody gets?

Speaker 2: I'm very concerned about the administrative avoided-cost check writing. I'm very concerned, first, because it's a calculation that may not reflect true value. And, second, it may be an excessive transfer to the suppliers. The suppliers may not be demanding that much of a payment to be perfectly satisfied in fulfilling that. So, I'm concerned about that transfer. I want to see competitive forces determine that price, not administrative forces.

Speaker 3.

Thank you. This is a very challenging topic, because there are so many myths and distortions and questions that one can almost not talk about it without getting into a huge debate.

So here are some ideas my colleague and I came up with. We're going to talk a bit about our encounters with hidden values and why we do think there are some hidden values that don't necessarily have to be hidden, but they're just not being considered in some decision making. But there's a problem not just with understating values, but there's also a big problem with overstating values, hidden values that are not real values. Most importantly, there's so-called "price suppression benefit" to customers from certain investments. And we want to talk a little bit about, well, benefits to whom? There are different perspectives on how one can look at whether a certain investment is beneficial or not.

I'm going to talk mostly about two studies we've done. One on the value of distributed electricity storage. We've done this for Texas. What we found is that the pricing where storage costs are going to about \$350/kWh, about 5,000 megawatts of storage would be cost effective in a market like Texas. That is sort of a stunning result because this moves the decimal point by more than one place, compared to what we are seeing now. But we also found out that you only get there if storage can capture all the value that it can provide simultaneously, at least, and that's both on the energy market side and the T&D side. Without capturing the full spectrum of value, you just won't get to that level of cost effective investment. And that does require new business models, because our regulatory structures are not set up for that.

The other place where we've seen a lot of discussion about hidden values is transmission planning. We've reviewed transmission planning many times. There are two public reports that we did, and what we found is that many economic benefits are not considered or are ignored or not understood in the traditional transmission planning approaches. We also find that planners and policy makers often do not account for the potentially very high costs and risks of an insufficiently flexible grid, and when it comes to interregional planning, those planning processes

are just not effective. They're unable to identify even the most valuable projects.

So what about hidden values? Well, we encountered hidden values in several different settings. The most obvious is externalities. Everybody talks about externalities. Well, there are environmental externalities. Carbon cost is an externality. If that's not priced in the market, that is something that market participants simply won't respond to, and as Speaker 1 said, that can be fixed by including these externalities in pricing. We also see externalities in merchant transmission development, for example, or merchant storage development, where the investment provides a broader spectrum of value to the system than the market participant can capture through merchant activity. That makes it very difficult to do merchant transmission, because the investor can't capture most of the value that the facility provides to the system.

We talk a lot about markets and what's missing in the markets, but we have to recognize that half of the country is vertically integrated and isn't relying on markets for investment signals. And the other half of the country has wholesale markets, but if you look at the typical distribution customer bill, that's only about half of the bill. So, half of the cost is still regulated, and even on the wholesale side, they're big regulated components. Other than in Texas, we have reserve margin requirements, resource adequacy requirements... That means, well, if you have a transmission investment that could reduce the region's reserve margin requirement, there is not a market mechanism for that. So we don't have markets to price distribution-level benefits and costs such as reliability and power quality, or, at least, they're not very liquid, these markets. We can do bilateral agreements with Southern California Edison, maybe, but these are not very liquid markets, so there are big transaction costs.

There are also no liquid markets for wholesale-level benefits such as reactive power, inertia,

black start capability. Some of the risk mitigation and transmission reliability benefits aren't specifically subject to a market mechanism either. And even when it comes to the wholesale energy and ancillary services, where we do have markets, there are some pretty big distortions. Much of the country does not have adequate scarcity pricing. With price caps at \$1,000 a megawatt hour, you just don't get to scarcity pricing levels that would reflect or internalize some of the reliability issues. And then you might have regulated contracts that sort of distort investment signals and distort market prices to the point where they cannot be used to make investment decisions.

And then there are regulatory barriers. Even in the restructured markets, half of the market is still regulated. There is an uneasiness about how transmission interacts with generation, how renewables are driven by markets versus contracts. In some jurisdictions, wires companies cannot own assets that also operate in competitive markets, such as storage batteries.

And then we have regulated planning processes that do not consider the full range of benefits or costs, whether it's integrated resource planning or economic planning for transmission.

And here's a simple example. A typical tool that's used for planning economic transmission projects or evaluating the economics of a proposed transmission project is just to run a production cost model and calculate production cost savings. The problem is that these production cost models are actually very narrow in how they capture what's going on in the industry. There are many benefits that I think we all could agree are real benefits that are not considered in the production cost model. They're not changing the generation capital investment. They're not factoring how transmission might change where generation is located, and things like that. But also, just by the nature of how these models are run, they're not capturing any sort of real time operational costs

that system operators incur. When you do consider these costs, you find that a project that's not economic based on production costs might actually be very economic once you consider those other benefits that don't easily fall out of a production cost model run. And by only looking at production cost savings and defining them so narrowly, you really risk under investing in the transmission system, because you fail to identify lower cost or higher value projects. And risk and the cost of extreme events or contingencies is barely analyzed for the economics of transmission projects.

So this is a list of economic benefits of transmission that are not captured in production cost savings calculations as the industry is currently using them. Now, you could define production cost savings to include many of these benefits. You can do a much better job running the model, but there's a huge list of things that are just not captured in what the industry is doing in transmission planning. One example is there are no transmission outages ever considered in those planning models. If you never have any transmission outages, you don't have much congestion on the transmission system. And no big generation contingency like a big plant being out for an extended period or forever has ever been considered in transmission planning. Generation capacity cost savings, because some locations have lower cost generation options than others, are not considered. Environmental benefits (mostly about internalizing carbon costs) are another example.

Unless we consider those other benefits in transmission planning, we are not able to identify the values that the transmission system can bring to the table. Now, why do we have to do this? Why don't we rely on markets? Well, the reality is that there is no real market for transmission investments. It's all done through reliability planning most of the time, and the economic planning is sort of an awkward integrated resource planning process that really

hasn't quite defined itself, what it should be, or where the handoff between regulated planning and market signals should be.

When it comes to planning transmission between regions, it's even worse. By the time you get to interregional planning, you get to a least common denominator approach where benefits that are considered for internal planning within individual RTOs are not being considered for interregional planning, and that leaves out even more values in the planning process.

But it's not always about understating value. We've seen many examples where these administrative planning models and determinations vastly overstate value. Often, value is overstated by ignoring market response. To give you an example from New England, Cape Wind was estimated to suppress wholesale market prices by, whatever, \$5, \$10. It's a huge benefit to customers. The whole offshore project would pay for itself in just a few years. Well, this doesn't consider the fact that if you were to suppress clearing prices, you would quickly have some generation retired or other generation not being invested, and prices would just not go to where you think they would be going. And the consumer benefit, the high consumer benefit of the price suppression just wouldn't be realized, at least not in the long run.

But values can also be overstated by coming up with these big laundry lists of benefits. Many of them are sort of counting the same things or counting overlapping benefits. So one has to be pretty careful.

But if we talk about generation investment response, in the work we've done on batteries, we've simulated the likely response of generation investments to the deployment of batteries, and if you were to deploy 5,000 megawatts of batteries on a distribution system, and let those batteries interact with the wholesale market, you would get about 3100 megawatts less in generation investment or in

higher generation retirements. So, on a net basis, you're not just adding 5,000 megawatts of storage and getting all the price suppression benefit of that. As it turns out, you're not really getting any price suppression benefit, because unless prices remain high enough to attract new investment or keep the existing investment in the market, you just won't be able to enjoy these lower prices. So, in the graph this is shown with two lines. The dashed line is the benefit, not considering the fact that generation investors would respond to price signals, and the dark line then shows the benefit that you get if you consider that investment response. And you can see storage does get you some system-wide production cost savings, but it's much less than you would have without reflecting that investment response. And with respect to the energy prices, there just isn't much of a difference, at least not in an energy-only market. And if you have an energy and a capacity market, it also shows up in the capacity market. And if you suppress capacity prices, then you don't get investment, energy prices will go up, and so on. So that really needs to be considered.

The other thing that we encounter frequently when it comes to renewables or even storage, is the idea of employment benefits, particularly for state policy makers. They love the idea that their state would be leading in clean energy, and building wind plants in a state with 25% capacity factor is great for jobs. But we have to consider that these are funny benefits, because if you spend a billion dollars, you can spend it on a wind plant, and half of the equipment gets imported from elsewhere, possibly from outside the country. So you get only so many state jobs. You could actually dig a hole and fill it back in and create more jobs in the state. [LAUGHTER] But that doesn't really do much, other than creating those jobs. So we think that while these employment benefits are very informative and necessary for policy makers, you can't just add them to project benefits for the purpose of benefit-cost analysis. You have to figure out what is the best project, based on the economics,

and then, if you also want to figure out what that project does for jobs, then that's useful information.

My last topic is, "Benefit to whom?" When you talk to developers, they are concerned about the merchant, and whether they can capture the value, or sufficient value. And the answer may be yes or no. When you talk to policy makers, they don't worry as much about who gets the benefits, but about whether society as a whole is better off. Is there enough societal benefit to warrant a certain policy? And then, of course, there are customer benefits. Every policy makers have to be concerned about customers, and that is very important. But if you can make customers better off and make generators worse off, that's not necessarily a long-term benefit to society, and you get investment response in all these places.

And the storage example is interesting, because, from a merchant perspective, you see here that you can capture energy and ancillary service values, in this case, up to 1,000 megawatts of storage, but that requires a very low cost of storage, and it requires the capability of the storage to charge and discharge on a daily basis, which many of the storage devices currently can't take, at least not if you want a certain life expectancy of the battery. So if you can't make money off the energy arbitrage, you're really only looking at ancillary services, and that is not high enough to cover the cost, even at this very low assumed cost of \$350 a kilowatt hour, which is about where Tesla is now pricing its equipment.

If you look at a societal value, the story's a little bit different, because if you can place the batteries in places on a distribution system where you have poor distribution reliability, or distribution investment needs, or transmission investment needs, you can capture not only the energy market values, but also the T&D values, and then what we found was that the incremental benefit of deploying storage is positive up to

5,000 megawatts. In other words, 5,000 megawatts would result in the optimal societal value of deploying storage. But the question is, well, should we do that, just because you can calculate the number? Well, maybe not, but maybe this is enough of a value to question whether policies should address barriers that might currently exist to the realization of these values.

But then when we looked at customer bill impacts, we found that the optimal size would be more like 3,000 megawatts of storage, and that is because the developer of the storage, the person bidding it into the market, will get some of the benefits, too, and total societal benefit would not all flow to the customers. So if you only concerned about customer bill impact, you could do up to 3,000 megawatts, and it turns out that the bill impact would be about neutral. But you get the reliability benefits for free.

So where does that leave us? Well, I think hidden values are a problem if they reduce the market payments that investors can receive. So if you just leave it to the market, and you have hidden values or partly regulated value streams that market participants cannot easily access, you don't get the optimal investment that way. That gets you to regulated planning, particularly where you don't rely on markets, integrated resource planning or economic planning of transmission. Those planning processes are prone to either overstating or understating benefits. So one has to be very careful about those.

We do think that policies should be focused on removing barriers to capturing value streams. If you know there's new technology out there that can provide three different types of values and you can create a regulatory policy that would allow market participants to access all three value streams, we should be thinking that way. And if one or two of those value streams are regulated, then it gets more complicated. Then we need to think about how to make the

interactions between regulation and markets work better. But overall, I think if the question is what perspective should we use to make decisions on policies, we do think that one should look at societal benefits, overall welfare gains, so to speak, and not just look at the distribution of investment related benefits.

Speaker 4.

Thank you very much for the invitation to be here. I get to be the contrarian on the panel, it seems. I feel like I could just take pieces from various presentations that you've already heard and tie a bow on it, but I'll still do my gig. [LAUGHTER]

I'll start with my conclusion first, because I always think that makes for good discussion. We've been locked in a discussion on efficiency in Alberta for a couple years now, and that's not just the ISO, but the regulators as well, trying to figure out what it is we're aiming for, how do we get it, what has the policy given us, where do we need to make some changes. And on this particular question of whether there is hidden value and whether we should go after it, our main conclusion, is that in our view, the market's not broken. In fact, if anything, while we have a very unique market and we'll talk about that here today, we've been very successful in delivering low price reliable electricity. So when we're challenged with the questions like, what do we do with storage, is there missing value, should we be trying to pay for that missing value, we have a really hard time landing on the idea that there is some value that's missing without us jeopardizing the rest of the market model. And that's what I'm going to talk to you about.

And secondly, to the extent there is missing money, what do you guys do with that? And we quote Alfred Kahn quite a bit in Alberta, and so, just to paraphrase, bad markets are better than good regulation. And you'll find that in Alberta we spend a lot of time throwing prices out,

developing specific products and having pricing on them, and try to avoid intervention to the extent we can. So I'm going to take you through that reasoning and I'm going to go through two particular examples that seem to be the examples of the day and tell you what we've done in Alberta on them--storage and carbon policy.

So, let's start with how our market is different and why we land maybe in a different place than some of you have. We are about as far from a FERC standard market design as you can get. We sat in our offices with popcorn, and we listened to all of those discussions, but we landed in a pretty different place. And just to focus on the key elements, obviously, we're energy only. We don't have a capacity market. Though I struggle with that conclusion more and more because we do have a separate market for ancillary services, we do not do security constrained co-optimized dispatch, so we do pay specifically for those products. We have a very deep ancillary services market, and so those are capacity payments. I mean, who are we kidding? The big one is our transmission policy. Our policy is clearly that transmission should not be in the way of a competitive generation, and that's how you get competition, and that's how you get low prices. And so, really, if I was taking Speaker 1's textbook example, I would show you the quote that all of the economists took way back in the beginning, that there are certain things that are natural monopolies, and transmission was usually used as the example.

So, with all due respect, that's our market model. We've said, "Look, it makes some sense for us to have one player in the transmission market and they'll do the integrated resource planning for the whole grid." Now, having said that, we have gone through a competitive process, but I'm putting that aside for a second.

In addition, though, to the market model, it was interesting to listen to the retail panel, because I come from Saskatchewan. I come from a regulated utility, and that whole kind of

thinking, but when you cross the border into Alberta, we're at an 80% load factor. We're very industrial based. We have very significant investments, so it really changes the way you think about everything when you've got an 80% load factor. We also have demand response that I think is the envy of North America, and we didn't get it by doing plug and plays on various products. We got it because demand is industry-based, and they're looking to manage their costs, so they're out there looking for energy efficiency. So they're at all the different parts of the curve, and so, when you talk about our \$1,000 price cap maybe being low, well, it's kind of doing what it needs to do, when you talk about demand being involved in the market at every price along the curve.

So our proposition is that there's nothing broken. In the energy market, we're able to dispatch the assets that have come to the market. We are fuel neutral. We are able to deliver energy. We buy the ancillary services that we need. They're standard NERC products that get us what we need to manage contingencies. And then, accordingly, we manage the ramp by dispatching the assets. That's how we get the ramp. So when we start talking about products like storage and, "Oh, there's this value and why don't you pay me for being able to manage wind and being able to manage the ramp," we sit back and do two things. One is we say, "OK, well, why would we pay you? We're already getting that." And maybe that's a free rider issue. I get that. But secondly, if we start paying for that product, what happens to the rest of the market? What happens to the energy price? What happens to the rest of the assets?

So let me go into that, using the examples of storage and carbon policy. On storage, the developers come to us. They knock on our door. They kick our door down. (Who are we kidding? They don't knock on our door.) And they say what Speaker 3 says: "There's all of this value, why are you guys not paying me for all of this value? If you just paid me for this value, I could

be on the grid. Why don't you pay me for this value?" But what we struggle with is that when we look through the list, the large majority of those are distribution values, and they're not ISO values. And even with respect to the transmission values, I told you our transmission mandate, which is that we have a policy to be unconstrained. So while we look at non-wire approaches, for us, historically, that's a short-term solution. We still look to build transmission, so it's really hard to kind of plug that in and figure out what that value is.

So when you look at the list (and these are kind of fighting words) it's really the ancillary services piece that's there, in terms of value for storage, and as I'm going to tell you in a second, that piece, we're getting it. We're getting the ramp. So, it's difficult for us to consider what we would create as a new product. So from our perspective, going up on the slide, the driver for the Alberta ISO with respect to batteries is that they're an alternative supply source, and we are fuel neutral. We are unbiased. So, short of there being a renewable mandate, batteries are an alternative supply source to us.

We started seeing batteries in storage in 2012, and it was really in response to the technology fund which came to us as a result of the climate change initiative, where there were specific pilots that came to Alberta to test whether they could make batteries attractive in Alberta. And there have been these various projects that have come, and none of them have so far made it to the queue. Some of them have been cancelled. So sometimes we ask ourselves well, is it a question of developer economics, and not so much a question of ISO needs? And you have to remember that for every battery guy who knocks on our door, there's 100 other developers that say, "Let's talk about the guys who are subsidizing our market." So it's really hard to have those conversations on one piece of the puzzle when the rest of the puzzle is so big.

So if I take you to the slide on the question of whether there is there more value, we're not naïve. We recognize that there's value for storage in the market. We recognize that if we did integrated resource planning like most FERC markets, and if we looked at non-wires more, there's no question that if batteries could be in certain places on the grid, there could be some additional value. So we're not naïve on that. It's just trying to figure out how you do that without unwinding the rest of the proposition. And that's separate and apart from the biggest challenge that they're facing, which is the fact that (although in FERC markets, you guys seem to talk about storage as if it's mainly supply) they take energy from the grid to fill their supply source to then dispatch means that they need to face a demand charge in Alberta. And in Alberta, loads pay for all transmission. So that looks like an economic issue to them. So, again, we're going through that conversation.

So we recognize there's some value, but where we usually land is that trying to somewhat artificially create products that we can somehow then give them money for, we think that would have a huge impact on the rest of the market. For example, with ramping, we don't have gas developers knock on our door and saying, "You're not paying me for how fast I can ramp. You're not paying me for the value of my megawatts. I'm way faster than the coal guys, why don't you pay me for that?" Having said that, we are starting to have that conversation in Alberta. Maybe we do need to look more at the value of the ramp instead of just the ramp itself. But right now, if we were to say "Oh, well, batteries can provide us wind supplement or additional ramp," we would look holistically. We wouldn't look just at batteries.

And so now there's a question of what that does. And if you dig deeper into the storage report discussed by Speaker 3, there's a section that I loved where it really talked about what happens to the energy price, and how the energy price is flattened when you now take away the ramp.

Well, our prices in Alberta right now are \$30. They're pretty low. We've got substantial wind. Our prices have gone from \$80 to \$60 average to now \$30. We are in excess supply. We are five years away from the power purchase agreements falling off. We need investment. Most of the investment has to be bank sheet financing because we don't have capacity markets, and you're asking me to maybe give a player a ramp price when I care about the energy price. I care about capacity price. So, without dwelling on that, you kind of get my point there.

So where we are on storage is we're looking at it. We just issued a second discussion paper. We're in our discussions with industry. I really do think the whole transmission policy is going to evolve, in the sense that we'll look at efficiencies at the margin, and now that we've built or we are building the big backbone, I think we will look at non-wires in the transmission requirement exceptions more. And so that's where it kind of fits in. But we've looked at the technical requirements for operating reserves and we really struggle with how we could lower the standards so that batteries can compete. So until batteries can get bigger, they can't provide the products we're looking for them to provide. And the tariff treatment maybe is going to be a bust, because of the way we charge loads for transmission. So there's still lots to talk about. It's not going to go away, short of the fact that it might, shifting gears from a climate change perspective, be hoisted upon us as a new alternative, on a fuel neutral basis, it's tough to find where the missing value is.

Now, having said that, let's shift to climate change, an externality that's not in our market, but clearly impacts our market. But in the meantime, we are trying to assess what we do with the objective related to climate change, which is a policy externality to us, while still running an electricity market.

There's no question that electricity is 20%, approximately, of GHG offsets, and coal is a

diminishing part of that. (This doesn't include oil sands. If you want to talk about oil sands, that's another discussion. This is just electricity.) And the point to be made is that if you're really focused on GHG, it's really not the electricity sector that's the biggest player in the GHG discussion, though we do recognize that coal is a piece of it. The original policy objective allowed for there still to be a growth in the economy. Actually, all of the policies in Alberta support the fact that we're a resource-based economy and we don't want to our GDP stopped just to achieve other objectives. So we really see that.

There is a federal policy that specifically says that, physically, coal must be phased out. And there's a provincial policy that actually says that after 40 years, you need a financial offset as well.

The emissions in the electricity sector are relatively flat. And this is going to be the moving target for us. And if you start asking yourself what happens when you change that target, it's definitely going to affect our assets, even though it's an externality to us.

Things are changing. The Specified Gas Emitters Regulation is the regulation that tells participants in Alberta that they need to target their GHG offsets to a 12% reduction relative to the original baseline (the 2007 baseline) or pay basically \$15 per ton on CO₂. And the announcement at noon today said we're changing that. We're moving from a 12% intensity reduction to 20%. And our \$15 is moving to \$30 within a couple years. So there's a new price on coal that's coming. And in addition to that, there's no question, that there's probably more coming in terms of phase out of coal and all that kind of stuff. We're talking about a price on carbon and possibly cap and trade, but it's equally possible that there will be a physical target as well. I mean, no question, coal has been targeted.

So, in short, my major conclusion to you is that

we are very market-based in Alberta. We're a bunch of cowboys, for sure (and come to Stampede. It's good fun). But we are very market based. We have big companies with big, big checkbooks, and they make big investments in Alberta, and that's probably why we've been so successful. And that includes the load side, as well. But when we start talking about missing money, and we talk about one particular product, which is storage, we really are trying to figure out, well, where are we missing it, what are we missing, and what does it mean if we were to change it? So we really are thinking that if we are fuel neutral, which we currently are (and I can talk to you about wind and what we do with wind), then, really, we don't think we're missing that much in terms of operating reserve product. There may be some efficiencies to be gained on the transmission non-wire side, but short of the climate change objectives pushing us in a direction that values that renewable side more, and maybe as an offset to coal, we think we've got it right for now. So I'll leave that as my contrarian position.

General Discussion

Moderator: OK, let's get started. And we're going to do clarifying questions and you can ask both Speaker 3 and Speaker 4 questions.

Question 1: So, on storage, you mentioned that some of the value was in the distribution side of things. And are you then not allowed to consider that by regulation? Or could you just clarify what the consequences are of some of the value behind the distribution side?

Speaker 4: Our mandate is clearly wholesale. Obviously, we care about what happens in retail and T&D and we have directives that can go out to the distribution side, but our mandate is exclusively wholesale.

Question 2: What is driving the storage? Is it an external directive, or did you all actually do some economic analysis and decide, yes, this

could compete cost effectively as an ancillary service with?

Speaker 4: No. No, it's all customer driven. So, storage customers came and asked us about whether they could provide ancillary services and why the technical standards were the way they were, and what the tariff would be if they were to actually compete in our market. So, it's all customer driven.

Questioner: When you mean customer, you mean the owners of storage, or --

Speaker 4: Yeah.

Questioner: So, it's pre-existing storage.

Speaker 4: Yeah, these are all customers, Suncor and etc., that came out of the technology fund projects. So there's a specific technology fund to support new initiatives, and these were some of the new initiatives, and then they came forward as part of that, and what they were studying is what role would they play on the grid, and what would it cost us, and all that. So, that put us in a position, then, to answer them. So we gave them our default answers. They didn't like our answers, so now we're going back and thinking more about our answers, but that's what drove it. The customer drove it. We don't do integrated resource planning. We don't try to optimize non-wires against wires. So it wouldn't have come there. And in terms of ancillary services, it's completely open market. So, short of a customer asking whether they trip through the technical requirements, which happened in this case, customers just participate in our markets. But that's where the tripwire was.

Question 3: For Speaker 3, on the study that you did for battery technology in the ERCOT market, was that done for ERCOT, or was that done for someone else?

Speaker 3: No, it was done for Oncor. They wondered whether there would be a benefit from

putting batteries on the distribution system. I mean, they have some pilot programs where they do feeder reliability improvements with batteries, but they realized that they can't access the wholesale market value. So they were just wondering what would be the value proposition of batteries in Texas, if you could deploy them in a way where you could access all these value streams.

Questioner: And that's a great segue to my second part of the question, which is, Texas being kind of a good model or at least we think a good model, for competition, when you follow that proposal of putting several thousand megawatts of distribution or batteries in the distribution system, which really is supply, don't you start to break down that wall that you've got between distribution and generation? And, essentially, when you've got a distribution company that's regulated, you're opening up that market or you're really closing off that market again. You're violating that sense of competition that we have, because you've got a regulated player with regulated supply in the distribution system injecting itself back into this market and really throwing the principles of competition off to the side. How do you reconcile how that would work together?

Speaker 3: Yeah, we actually thought quite hard about this. So, if you want to have a regulatory structure to realize these values, let's say you were interested in realizing these values because they're compelling enough. What kind of structure do you need to avoid either subsidizing batteries through a regulated treatment, or not making the regulated value streams accessible to market based entrants? So, you either have to find a way to make the regulated values accessible to market based providers, or you have to find a way to make the competitive benefit available to the regulated storage provider. And we thought one option might be for the regulated company who owns the batteries on the distribution system to auction off the competitive value of the batteries. So, in

extreme, you could say, “Well, the battery costs a million bucks. How much is a competitive provider willing to pay me for the dispatch rights?” And let’s say they’re willing to pay \$600,000 for the dispatch rights. Then you would have to have a net regulated cost of \$400,000 and you would have to prove to your regulator that it’s worth investing \$400,000 to get the regulated pieces of value stream for avoiding T&D investment and providing customer reliability. So you can separate that through an auction process.

All of this is a little bit awkward. You could allow a joint venture between a competitive company and a regulated company, and there are other forms. You can do it like in California, where you just do a mandate on the distribution company to build it and bid it into the competitive markets, but that creates the problem you point out. So I think the problem is an important problem to address. I do have to say we already have experience with that, and that’s the uneasy experience with transmission planning, because transmission is a regulated asset, but it greatly affects markets. So whatever we do on the regulator side with transmission, we already have market impacts. So I think we can’t hide behind the fact that half of the assets involving the electricity industry are regulated, even in the restructured markets. And now we have new technologies--all the distributed technologies, basically--in a spot that’s on the regulated part of the system. And whether it’s storage or solar power or something else, we need to find a way to allow investments to bridge that gap.

Questioner: But you don’t have a sense of confidence that the value of the ancillary services in the marketplace on the unregulated competitive side would solve that problem?

Speaker 3: Well, no. I don’t. You might be able to deploy storage just based on ancillaries and energy market arbitrage, and there’s a marketplace for that, but we also show that that

throws away about 40% of the value that storage can provide. So, the question is, do you just want to not go after that other 40%? Or do you find a policy that would allow storage to be deployed in such a way as to capture both the energy and ancillary service markets value streams, and also the regulated value streams?

Question 4: Just a quick clarifying question for Speaker 4. Do you have any special rules for new merchant generation, given that you have a single price market, to ensure that they get located in an area so that they’re not exacerbating transmission constraints?

Speaker 4: No. Generation can locate wherever it wants.

Questioner: And so, if the generation locates in a bad location, then the transmission owner is simply required to upgrade the transmission so that they’re deliverable?

Speaker 4: Yes. Now, there’s a gray area in there. What happens is that a generator owner tells us where they’re going to locate. We’ll do a study. And if the study indicates that there are constraints, then we kind of work it out. And we can look at non-wires and look at how we manage that constraint. We try to deal with all of our constraints in real time. So what we will do is we’ll first and foremost flag whether it’s an N minus zero or an N minus one constraint. We tell the market about it. If it’s N minus one, we will deal with it in real time and let them connect. If it’s N minus zero, then we have some timing issue around it. And we’re in a couple of hearings on that one right now. But generator owners can locate wherever they want, and we provide information and transmission plans.

Question 5: This is a clarifying question for Speaker 3. I was wondering if, in your study in looking at the value on transmission investment, whether you were able to look across US jurisdictions that have very different policies on merchant transmission. Does the ability to

capture some of that value change across jurisdictions? Have you been able to look at that?

Speaker 3: Yes, you make a very good point. The short answer is we have not looked at state siting protocols, like what does a state require to prove the need for a project? What we've looked at is at the RTO planning processes. And what you bring up is a very good point, that even if the RTO planning processes were perfect in every way, you're still stuck at the state level. If you have a line crossing three states, they have three different ways of evaluating the need for that line, and that, I think, is a big problem. Although it does seem that more and more states, even in the siting processes, are deferring at least in part to the RTO planning processes. So you have a good point. We have not specifically looked at the state regulations, but we know that's a challenge.

Question 6: This is a question for either Speaker 2 or Speaker 3. When you're considering generation on the distribution system, or, for that matter, things like storage, have you all considered the alternatives, for example, looping distribution theatres instead of radial, and putting remotely controlled breakers and that sort of thing, in order, for example, to bypass faults and isolate the reliability problem, as opposed to investing in all manner of other expensive new infrastructure because it's the favorable technology de jour, in terms of the cost effectiveness of one or the other?

Speaker 2: Well, we're revisiting the whole way we do distribution planning in light of this. So, as we work through these issues, our PUC will be very interested in alternatives to whatever we're presenting. So the long answer is, yes, we're looking at everything. But still, the belief is we need to change the way we're doing things if we're going to have two-way power flows through our distribution system.

Speaker 3: The short answer is that we have not specifically looked at alternatives. What we found was that to make batteries do their job on a distribution system, you actually need smart switching, because if you can't isolate the feeder, the battery doesn't really do anything for you, right?

Questioner: Did the cost analysis make assumptions about the cost of doing that?

Speaker 3: No, not this one. But a lot of utilities are now having programs to make the distribution system smarter, so we pretty much assume that the batteries would follow that investment.

Question 7: First, one slight clarification question for Speaker 3. In your study, did you compare the storage options against any other technology options, such as just combined cycle power units, in terms of the kind of benefits you would get from that? Or was it just looking at storage?

Speaker 3: No, in terms of societal benefits, we just looked at the avoided cost of reduced generation investment. So, in that sense, we let storage compete with conventional generation investment.

Questioner: My second question is with respect to storage. Assuming that we allow storage to participate in energy ancillary service capacity markets, as it does in, say, ISO New England with pump storage units, can you explain to me where the market failure is, or where the missing market is that isn't a missing market for any other competitor in the market? I guess I'm just fundamentally not quite seeing, from a technology standpoint, how storage differs from other resources that are competing in the market.

Speaker 3: There's not that much of a market missing on the wholesale power side. I mean, there are some markets where they don't have fast ramping regulation and so on that might

benefit storage, but we assume just the plain vanilla ancillary services in energy. What we found, though, is that if you are a merchant storage developer, you can easily get ancillary services and energy arbitrage values, but you can't access the T&D and reliability benefits of that storage very easily, unless you put it all the way behind the meter. But if you're behind the meter, then it's harder to access the wholesale energy market.

So there is the way regulation is set up. It makes it very hard for either the merchant storage provider to access the regulated value streams, or for the regulated service provider to access the market-based value stream. It's hard for deregulated market participants or just wires companies to access all these value streams.

Moderator: So, what he's saying is we're putting the companies back together into a vertically integrated company. [LAUGHTER]

Speaker 3: That's not what I'm saying.

Question 8: Thank you. It's a question for Speaker 3, but, obviously, other people might answer. That was a great presentation, and I agree with a lot of what you said. My overall question is, do you view this differently in the context of an RTO or a utility evaluation of need of a project, or a CPCN (certificate of public convenience or necessity) proceeding?

And I raise that because I've just recently participated in two CPCN proceedings, neither of which are still at the state level. They're in the court of appeals.

But the first question is, how would you model transmission outages? We've talked to the RTOs. We've seen actual data that shows that congestion goes significantly up during outages, and may actually constitute the very few days of high congestion. It also affects maintenance. You have to take things out. The second thing is, where you have capacity markets with lower

energy prices, what do they do? You mentioned the studies not taking into account market reaction, but even if they did, what do the lower energy prices mean? That you have a benefit, due to the likely higher cost of capacity because of lower offset? And then, the third thing that we've seen is pure merchants coming in and saying, "Every cost is a benefit, because the state gets taxes," or something like that. So, from an economist's point of view, how would you see that? Because I do see differences in a state proceeding than I do in an RTO proceeding.

Speaker 1: I think a ubiquitous problem here is the cost or benefits and transfer of benefits mentality that will exist in states in smaller entities all the way down to the individual. And I agree with Speaker 3 that the bottom line should be the social welfare calculation, and we should focus on efficiency, and we shouldn't be in the business of adopting policies which are expensive in order to borrow from Peter and give to Paul.

Speaker 3: One thing that would help would be to encourage states, to defer more to the regional planning entities, and then have the regional planning processes be improved. Then one at least would get regional planning. On reliability, it sort of works, because most states accept reliability needs more readily than economic needs. But I think where these things work reasonably well is places like California, where the CPUC is quite deferential to the ISO's analysis of need.

Speaker 2: I'd say even beyond deferential, cooperative, especially in its policy development. There's a real interaction, where the state basically gives our ISO their best guess of where rich renewable resource areas for development are. The ISO does transmission planning to try to reach those regions. So, I'd say it's very cooperative.

Speaker 3: Yeah, on some of your other questions, of course you can't count every cost as a benefit, but if you have a cost and you spend money, you might say, spending money is good, so that's a benefit. The cost benefit calculation doesn't quite work like that. And you'll just have to explain it as best as you can. On transmission outages, we have some ideas that we've written up in our reports and we'd be happy to discuss that offline. I think there's too much detail right now.

Speaker 4: If I could just add, from the energy only market perspective, the conversation that we're having is, on one hand, you would have a productive efficiency gain, because you would have lower priced resources offering into our market, in theory, much like wind. But on the other hand, you'd have a static and dynamic efficiency loss, because we need that price signal to provide both real time response and investment response. And so if we were to do the whole sum analysis, and this is maybe we don't do that, but if we were, you'd have to factor in what happens long term, not just what happens in the short term on the price signal of an asset like that. Which is why we think that it more fits into the ancillary services market, because that's a specific product.

Questioner: This is my question question, not my clarifying question. And this question is really for Speaker 1 and for Speaker 3 about the hidden values of transmission investments. You talked about large scale transmission potentially being lumpy investments and, Speaker 3, you spoke about production cost models sometimes not being able to capture the actual benefits from these projects, and how they can underestimate it, but they can also overestimate it.

I'm curious to have a discussion maybe between you two about thinking about those transmission investments in the context of, how do you account for the need for new capacity and new generation capacity as you're considering transmission investments? Because, as I think

about it, years ago, the question for transmission investment was, how do we move the cheap power from the Midwest into the East? And that's where a lot of the transmission constraints were, and that's where a lot of the large scale projects were, like Trail and Path, and things like that. And now, we're getting so many changes in the generation profile, with new generation located near the Marcellus in the East and coal units retiring, that things are entirely shifting. And when you look in a timeframe of five to 10 years, generation and transmission can actually be substitutes. And so I'm wondering about those lumpy transmission investments. I just worry that you could get a billion dollar transmission investment that actually moves the needle for a market participant who's really being pushed, when there could be any number of small scale transmission investments to upgrade a transformer or little investments on the grid that don't move the needle on transmission investments when combined with generation upgrades that could solve the same problem. And how do you ensure that you account for that? There's also a study out there that's looking at these kind of alternatives. I'd just be curious to hear what your thoughts are on that.

Speaker 1: Well, I'll go first. This is a very hard problem. We can do as well as we can do. So, the answer in principle is pretty straightforward, which is that you want to do a calculation going forward which does not say we freeze the generation mix and we look at the dispatch differently and we don't consider effects on investment in generation, and that's how we do it. That's obviously the wrong way to do it. It's incomplete, and you're not looking at how it's going to affect investment in generation, and that's all part of the story. So you have to do the best that you can do, and we do have these models going forward that have varying degrees of sophistication which have endogenous investment in them. So that's part of the tools that are actually out there.

Secondly, there's a lot of uncertainty. So you have to do lots of scenario analysis. And the Midwest ISO, I know they published a study one time about how they do that, and decision analytics, and then probabilities associated with this, and, "we could go this way, and we could go that way, and then we calculate the expected value, and we go back and forth..." That is going to be imperfect, and it is also going to be wrong after the fact, by virtue of the definition of uncertainty, because only one of the outcomes is going to happen, not all of them. But it doesn't affect the evaluation of the costs and benefits. We should try to do that as well as we could do. And then we should have one of the byproducts of that kind of analysis (and we know that it can be done because it has been done in places like the Southwest Power Pool) which that it kind of inherently produces the realization of the diagram I showed, which is showing that the benefits go here and here and here in these different buckets and categories. And now we can do the cost allocation that is consistent with those benefits. And that's a doable thing. It's hard to do, but we can do that.

And in that calculation, you should be looking at the alternatives. So the base case should be, we don't do this transmission investment, then people invest in batteries or whatever else that they assume. And if this is how the analysis comes out, we say, "Well, it's not worth doing the transmission investment, you should invest in batteries." The point I'm making is that it does not mean, then, that we should do regulated investments of batteries. We should just let the prices be what they are, and then people will invest in batteries because that turns out to be the good thing to do because the transmission isn't there. But it's only the transmission which has this lumpy characteristic. You get it all of it or nothing, in some of the scale that we're talking about where you have this regulatory problem.

You do the best you can do with the cost benefit analysis. It will be imperfect, but it will identify

whether or not you pass the golden rule test: is it worth it? And then, secondly, it will identify who's benefiting, and that tells you how to allocate the cost, and is consistent with the hybrid market. And you don't have to do anything for anybody else. You charge congestion, standard locational prices for everything else, and batteries could take advantage of that in the merchant market. And if they make money, they make money, and that would be terrific. And if it's the flow based battery that my colleague, Mike Aziz, is working on, that would be even better. [LAUGHTER]

Moderator: I'm going to jump in and ask, now that you all have heard each other, is there anything that any of your colleagues said that you would like to address or respond to?

Speaker 1: I was struck by this morning's discussion about residential demand charges, and I'm a little more alarmed today than I was yesterday about this problem of the inflection point. We're getting too far down the road of subsidizing all these different new things that are coming in and creating grandfathered situations. And I've always been worried about this, because there's a horse race going on between all of the regulations and subsidies, and then trying to perfect the markets. And I don't know who's going to win. Lately, I've been feeling concerned that the subsidy system is just going to overwhelm the markets. And if you put together the conversation this morning about net metering and the effect of PVs, which I am concerned about, with the implications of the fact that we don't know what EPA is going to do. The Clean Power Plan is not actually a plan. It's a proposal for a rule for a standard, but not a plan about how to implement this. And so there's two years there or three years yet to come of conversation about what that actually is. But if you look at that map that Michael Worra put together, you go "What is going on here? There is really something bizarre about this." And Phil Moeller is not here in the room this afternoon, but he was quoted the other day at a

public meeting, saying something to the effect that if you're the state regulator in the public utilities commission or you're at FERC and you don't know the state air regulators in your state, go meet them, because they are taking over planning of the grid. I'm not completely sure that was an exaggeration. And so we may be at a really serious inflection point here where this whole idea of taking advantage of markets and the incentives and the risks and rewards balancing is going to be replaced by central planning that is going to make the avoided cost mistakes of the past that led to electricity restructuring look even worse. And now we're going to have to go through it all over again.

Speaker 2: There was an undercurrent or a theme about jurisdiction that sort of bubbled up here and there. Speaker 3 was talking about assets being put in the distribution grid, and not having access to the wholesale markets, and vice versa. I think that's going to become an increasingly complex discussion that is going to interact both ways. What I was trying to frame is that to the extent stuff was on the distribution grid, if the retail side can mimic what's going on in the wholesale market, and sort of give those wholesale prices to the retail participants, that might be a way of both bridging the jurisdictional issues and providing the value to the providers that were there. Just an observation. I'm not sure how all the jurisdictions sort out. The first thing that comes to my mind is sort of this MOPR concept that happened on the Eastern markets, where certain generation was viewed as depressing capacity prices and not allowed in the capacity market. And then, there was an issue brought up of distributed resources coming into the distribution grid with potential subsidies having a similar type of potential impact, and I think the proverbial elephant in the room is RPS mandates, where California's moving towards 50%. These are happening and consistent with what was being noted about subsidies. It is concerning to me how all these are going to

work out jurisdictionally and preserve a workable wholesale market in the process.

Speaker 3: I think the world is changing quite fundamentally. When the industry was restructured, we basically thought, that's a one-way street from generation to transmission to distribution, and we could cleanly separate the deregulated generation market from the rest of it. I think whether we like it or not, it's just gotten a whole lot more complicated with distributed generation, with, whatever, storage, demand response... I mean, just if you look how demand response complicates wholesale power markets, it's quite something. So I am concerned that with all these complications and the difficulty of sorting these things out rationally, people are just running out of patience, throwing up their arms and saying, "I'm just going to mandate these things or subsidize renewables. It's much easier to have an RPS standard than to have a price for environmental attributes."

And because it's so complicated politically, I think where the industry's going, including in the RTO planning processes, is that people are doing what can be done most easily, which is not what makes the most sense. And I think the CPP proposal is an example. This is probably the best they could do, given the political and legislative constraints they're faced by. It's just a very odd mechanism that's very far from an economically rational mechanism. So I would appeal to all policy makers to not throw up your arms so quickly and say that, look, we are to rely on markets to the largest extent possible, and where we can't allow markets, we have to come up with a rational scheme that looks at the value proposition and not just at regulated mandate. I mean, take California. The storage initiative is great, but mandating 500 plus megawatts of storage is not exactly thinking through the value proposition. It's just the easier thing to do. And I think we can do better than that.

Speaker 4: The idea that it's much easier to just impose a mandate, but that's not necessarily the

right solution, is actually the theme I was thinking of. It is exactly with respect to that question that I would say Alberta's market's been successful. I would say a number of the FERC jurisdictions have been successful as well, but as you start piling on incremental obligations and incremental challenges, where you're trying to squeeze out the marginal efficiency, on each little piece, is there a way to stay the course? Because you guys have low load factors. We at least have high load factors, but we always say in Alberta, you've got 20% of the load from the residential sector, so 20% of the load factor is 100% of the voters. And you still need to stay the course where you're adding objectives. So, Speaker 1, do you have a solution here that you forgot to hand out that you now can hand out, so we can stay the course? Or are we just going to go full cycle on the pendulum to well, we should go back to regulation because it's bigger than we can handle and then let it bust again, and then go through that cycle?

Speaker 1: I mean, I've said it before and I'll repeat it. I think there is and will be no shortage of people who want to get mandates in favor of their thing. So, "I want this and you should pay for it. And I should get the benefit of it. And so, I'd like a \$10,000 Tesla." Thank you. That would be nice if somebody would give me that.

But the question is, who is the group that has responsibility for protecting the integrity of the competitive market? And that's fundamentally the regulators. And it's the state regulators and it's the federal regulators and the RTOs as their instruments. And they have got to maintain their focus on doing that, and it's politically difficult and it's not easy. But they should be focusing on that, and there's a serious problem. And I've talked about this before in front of the technical conferences at the Federal Energy Regulatory Commission. I said that we have just not been doing our job in this regard. I take some of the blame for this, but if you look at these reports that come out of the market monitors, and David Patton and people like that, they have these

issues, "You have to fix this, you have to fix this." And they just go on and on and on, and they don't fix it, and all we're trying to do is to make the capacity market finally work. Which I think is a feckless pursuit. [LAUGHTER] I understand why the pressure is there. But I think the model of the scarcity pricing in Texas is a good model, the kind of thing that should be done, because it answers an awful lot of these questions. It just puts them to bed, to say, "There it is, and that's what it's worth, and that's what we're willing to pay. And we're not willing to pay any more. And that's it." So I think improving the market design, protecting integrity of those markets, that's a fundamental responsibility for people like me and for regulators, and we should do better.

Moderator: So I think his answer was, "Texas is the answer." [LAUGHTER]

OK, so let me just say, I guess let me say this as a statement, and then ask if anyone disagrees. I see the winners and losers created by the Clean Power Plan rule making driving states further apart in planning, rather than bringing them closer together. And I would just ask if anyone has a response to that.

Speaker 1: Well, there is a paper that was done by a group at Berkeley and MIT and a bunch of other places like that. I think Jim Bushnell was the lead author on this, which addressed exactly this question. And there are a lot of things you can complain about with respect to the Clean Power Plan, and I won't get into the details, but they did try to do the simulations of this and that. And, basically, their conclusion was what you just said. Which is that the Clean Power Plan rhetoric is, "flexibility, flexibility, flexibility, cooperation, cooperation, cooperation," and the incentives are, "battle, battle, battle, battle, don't cooperate, don't cooperate, don't cooperate." And I think if you look at that map and you see, "Gee, they set me up for something where I don't have to do very much, why should I cooperate?" I mean,

think of Vermont. So, it turns out Vermont doesn't have any impact on carbon emissions, according to the Clean Power Plan.

So when you consumer power in Vermont, you're consuming carbon-free energy. It's terrific. [LAUGHTER]

Moderator: Same as California. I think the moral of that story is, if you import your power from somewhere else, then you're good.

Speaker 1: Yeah, right. Exactly. Now, I don't fault the EPA for this. I think there's the problem that Speaker 3 identified, which is that they're looking at the legislative constraints, and they're operating under the Clean Air Act. The Supreme Court decided that CO2 was a pollutant, so that settled the legal jurisdictional issue. That doesn't mean it made any sense. And now they're operating under the constraints of that law, and they're trying to do things that torque into that law, but then try to do something good, but they're constrained as to what they can do. And then, in the end, this is going to have to be solved in Congress. I mean, I don't see how it cannot be. And Schumer said it the other day, and yesterday. He came out in favor of a carbon tax. And, boy, if you could put that together as a substitute, rather than an add-on, to the Clean Power Plan, then I think that would be terrific.

Speaker 3: Your question is a really, really good question, because there are several studies out there. Almost every region has studied this question, and they found that the total compliance costs for the Clean Power Plan are lower on a regional basis. The only challenge is that there's so much divergence between the states that the money transfers that would be needed to achieve a regional equilibrium are huge. And those kind of transfer payment, even if everybody in the region was better off doing them, in the end, I think, are not politically acceptable. And maybe we'll end up in a very suboptimal, very high cost compliance world if

the EPA doesn't find a way to modify the ultimate proposal.

Question 9: It's very interesting. We talked about all these missing values and so on and price suppression. And I have a new word for this. We call price suppression "buyer side market power." But, as I was listening to the conversation, I'm thinking, well, who's actually coming up with these policies and promulgating them? It's regulators, whether they're legislators, actually, state commissions, or environmental regulators. And so maybe it's regulatory market power instead.

I hope the regulators in the room don't want to shoot me for that. I'm sure they will. But my question is more philosophical, and that is, since when have we become so afraid of transparency in pricing? And maybe I know the answer to this and maybe I don't, but I'd like to get everybody's take on this. Why are we so afraid of transparency? Because effectively, Speaker 1, that's what you're proposing. If the price is right, make it transparent.

Speaker 1: Well, I'm not afraid of it. [LAUGHTER] I'm in favor of it. And I think if you don't do it, and you give people discretion so that they can choose what they're going to do in response to the prices that don't give them the right incentives, you're just creating problems that are going to be much harder to solve later on. So if you don't want to have transparent prices, then you can't give people discretion. That's the fundamental dilemma. And so, you can tell people what they have to do. They don't get any choice. Then it doesn't matter what you charge them. But if you want to give them choice, you'd better give them the right prices, or else you're just creating more trouble.

Speaker 3: Well, the other problem with transparency is that it would tell us that some of what we're doing actually doesn't make much sense. If you really want to get some carve-out, transparent pricing wouldn't be that good,

because it would just show that some of the RPS requirements have a carbon cost of \$150 a ton. So I think it's a really hard problem, because there are hidden values, or externalities one has to try to internalize, but a lot of market participants realize that that's not where the biggest payoff is. And it's much better to implement a capacity performance program, or a storage carve-out, or do something else, but I think it's a problem, because it makes the market so awkward and complicated and untransparent. But everybody has their story: "Oh, we have to save base load plans," or, "We have to get storage," or, "We have to get solar and we have to do net metering." And it's all overstated, and transparency would be helpful, but it wouldn't be helpful to the interested parties.

Questioner: So, am I to take it that rent seeking behavior trumps markets?

Speaker 2: I'd say, from my perspective, that policy objectives trump short-term market efficiency.

Speaker 4: Yeah, I've got some money on that, too. The example I was thinking about when the question came up and I thought well, you don't want to hear the Alberta story again, but it's interesting, in that our prices are really low. So, what happens when we have excess supply and prices are really low? The business people do the right thing, right? They say, "Well, then I don't want to be here, because if the prices are really low, then I want to mothball." And we have rules in our market on long lead time assets. And so, they say, "Well, just call me a long lead-time asset, but my length is months." And so you go through that cycle and say, "Well, this is the exact time in the market where the consumers are actually benefiting," but you sit there with your hat on and go, "Well, they're doing the right thing. Prices are low. That's what generators should do." But this very quickly goes to public policy. Like, how do I make sure this market is sustainable? Because we're in this period where we need investment to come on,

and prices are wrong. So, is that market power? It's physical withholding. That's what I would call it. But it's also the right business decision. So it very quickly slides to what's the right public policy decision.

Question 10: To Speaker 4, how would you have an energy-only market (which we know is preposterous because without a capacity market, it can't possibly work)? In a region where you have all this load growth, did you get into a surplus capacity problem? Because that can't happen, according to the way we're thinking now about the need to subsidize capacity of all forms.

Speaker 4: We're a big business province. We are very resource-based, right? So these are big business people who have first mover advantage, and they're sitting on brown field sites, and they know that. We've got the PPAs expiring, so that is probably the anomaly that trips it a bit. So in 2020, the relationship between the buyers and owners on the old incumbent plants expires. So there's a bit of a first mover challenge that goes with that, and probably linked to that is the climate change green response. So you've got plants that are trying to position themselves as being cleaner. You end up in surplus when you have a big company build, and that was the most recent one.

Now, the anomaly, the one that I'm struggling with a bit, and we're struggling collectively a bit, is that it's not bank sheet financing. It's a customer who has inherent load. So if a generation developer has a default customer, then it's kind of easier for them to get bank sheet financing, because who pays for it? I pay for it as a city of Calgary taxpayer. You're not supposed to say that out loud, but that's kind of what it looks like. And they've got partnerships with other customers, but you end up in cycles where we have excess supply. Now, prices a couple of years ago were \$85, so there could be some response to that, right? You're moving ahead on the price curve, and then when you

come on, generation's lumpy, too, not just transmission. And so wind has been coming up, as the transmission is there to fulfill it at the exact same time that this generation plant went from whatever it was, 200 to 500. So it gets lumpy real fast. And that will, literally, squash the price.

Question 11: Speaker 3, when you talked about who benefits, you described the merchant value, the customer value, and the societal or system-wide value, and very quickly concluded that the societal or system-wide value trumped the other two as a policy objective. And there was some discussion a few minutes ago about the Clean Power Plan and its ability to look at regional versus state solutions. But it seems to me that the question of what defines the system-wide or societal benefit is going to be a very, very difficult challenge. There are clearly state drivers. There are federal drivers. There are regional drivers. There are national drivers. And figuring out how to pick and choose what the boundaries of that societal or system-wide entity are for the purposes of determining the benefits may be an extraordinarily difficult challenge. And it may be the focus of the discussion tomorrow morning, so I don't mean to preclude that by any stretch. I understand how you got to societal benefit, compared to the other two, but I don't see it as a simple thing to do.

Speaker 3: Well, unfortunately, nothing seems to be simple anymore in this industry. I think societal value is the right answer, and our society doesn't stop at the state boundaries, nor does it stop with the consumers. I think, as Speaker 1's framework for transmission pricing shows, if both generators and customers win, such that the customer benefit might not be that large, but the generator benefit adds on, then you can do cost allocation with that. In some ways, if you have a societal benefit that's positive, it tells you it's a good investment. If you're going to look at the other perspective, it helps you figure out how to allocate the cost of that investment.

With the Clean Power Plan, you would have to move a lot of money across state boundaries to sort of create a regional optimum, lowest cost compliance plan. That becomes difficult. But I think that, at heart, that's what it is. You use a societal perspective to figure out whether this makes sense overall, and then you use the perspective of the individual market participants to figure out who wins and who loses, and that comes before cost allocation.

Question 12: One of the themes, I think, throughout the day and often throughout these conferences, is that you would get a more efficient approach if we could use a pure market approach, whether it's the price on carbon or scarcity pricing. But one of the challenges, obviously, that regulators face, and I'd say state regulators face it very directly, is that we have to worry about people who can't afford electricity. We heard about that this morning. And we also have to worry about some of these other externalities that we always say well, there's externalities.

But even if you take the Clean Power Plan example, there was a very strong effort to try to achieve a price on carbon, the Waxman-Markey effort, and it failed. So maybe the Clean Power Plan is a second best effort. And I'd sort of put maybe the renewable portfolio standards in some of that same pocket. So I guess the question I have is, are we supposed to just wait for the nirvana of having a market system that would work that would then allow us to have the policy tools we need to redistribute, to ensure everybody can have universal access, and ensure that we take care of the pollutants and other kind of policy objectives that I think many in the public have? Or is it appropriate to try to find a second best option, which is what I think we often end up doing? So I just wanted to throw that back to you and see what your thoughts are. Because that's how I look at it when I see things such as renewable portfolios and other tools that we use.

Speaker 1: Second best is better than third best and fourth best. So, obviously, it's not going to be perfect and the standard of perfection is unhelpful. And the problem that I worry about with these things...there's Germany and there's Spain. So, both of them put in second best policies. Feed-in tariffs for the renewables. And they spent a lot of money. A lot of money. The unrecovered costs that are on the books for the utilities in Spain to support the feed-in tariff, the regulatory asset, as we would call it here, now exceeds one year's gross revenue of the electricity sector. So there's a lot of money that's hanging out there. They spent a similar amount of money in Germany. They've been saved in part by exogenous things which caused the electricity prices in a regular wholesale market to go down, so the total cost hasn't been passed through to the final consumers.

The political reaction in these two countries is astonishingly different, as I understand it. So, the political reaction in Spain is, 'Never again! That was a huge mistake. We really screwed up. We're getting rid of all these subsidies. We're getting rid of the feed in tariffs. We're not going to do this.'" The political reaction in Germany is, "It's worth it. And we're prepared to pay the money," and that's a choice that they can make and a policy choice. What I worry about is that we're more like Spain than Germany. And if you put in these incredibly inefficient things that are going to create these regulatory burdens, the arbitrage opportunities that are embedded in this for regulatory mischief across different regions, and building plants over here that are really for over there, and all the kind of stuff that's going to happen are going to create a real mess.

And the concern that I have is that what we'd end up doing is spend a lot of money, and we'd end up rereading Bill Nordhaus's quote 10 or 15 years from now, which is that we didn't do anything for the environment, so it was not good for the environment. It was just expensive. And then we have to start all over again. And we're wasting a lot of time. And this is a serious

problem, this climate problem. I agree with that, it's a serious problem. So I think setting up things which are just bizarre when you look at them...they're not just second best, this is way down the list here... Now, I think that's because they're constrained. And what I'm hoping for is the Schumer carbon tax idea. And it's happening. You see more and more people are starting to recognize, and I think they're going to do it, not because they are worried about the integrity of the electricity market or they're worried about the environment. The politicians need the money. And there's going to be a big meeting where we're going to rationalize all this, and a whole bunch of tradeoffs are going to get made, and we're going to get a tax on carbon. And I think it should be large. I don't think it's guaranteed that it's going to happen, but I think it's more and more likely, the more days go on here, as people start looking at it, and when this Clean Power Plan thing starts really moving, and they start talking about what they're actually going to have to do in order to meet all this kind of stuff and the craziness there, there's going to be enormous pressure to do something else instead.

And so I'm hoping we get to the something else instead. Now, if you told me I have a binary choice between doing nothing and doing the Clean Power Plan, I would take the Clean Power Plan, because something's better than nothing. But that's a pretty weak standard. And I think the danger is that this is Spain, and that there could be a revolution here once we start recognizing these costs and the inefficiencies that are being imposed on the system, and the Cape Wind nonsense...I mean, don't get me started. The reaction that's going to come is going to be more harmful than the benefits that people claim they're going to get. So I would like to see us do something more sensible and keep fighting for it now, when we have a chance.

Session Three.

80 Years of the Federal Power Act: How Has It Evolved and What Lessons Can We Derive?

The Federal Power Act (FPA) turns 80 this year. It has evolved over the years from a Congressional effort to fill a regulatory gap identified by the U.S. Supreme Court in the Attleboro case--namely regulation of interstate commerce in electricity--to a far more comprehensive framework of regulation over wholesale power markets and high voltage transmission. That evolution has both tracked and enabled the changing nature of the power market from vertically integrated utilities to fully competitive bulk power markets and from a closed transmission access regime to an open and dynamic one. The evolution has also been marked by a massive shift of regulatory jurisdiction from the states to the federal government. In the absence of major statutory changes to the law, this evolution has occurred through judicial rulings and through sometimes aggressive federal regulatory actions. Going forward, there are at least two subject areas that are almost certain to impact the FPA. The first is the increasing presence of distributed energy resources in the marketplace. While they have traditionally been seen as an inherent part of retail markets--still largely the domain of state regulators--their effect on the overall market is likely to be such that it may well attract the attention of those responsible for the FPA. The litigation over jurisdiction regarding demand response is not only exemplary of the types of controversies that will emerge, but may, in fact, be the harbinger of what is to come. Another challenge, of course, does not involve state/federal jurisdictional issues, but rather the interface of two schemes of federal regulation: the FPA and the Clean Air Act. The debate over 111(d) and its impact on the power market is illustrative of what may lie ahead. How will the FPA evolve to meet these and other challenges in the future? What lessons can we derive from the 80 years of FPA history that will help us move forward?

Moderator: Good Morning, everyone. We are going to talk about a legal issue, and specifically about the Federal Power Act, which is now 80 years old. And I think that as we all know, even from the discussions yesterday, that interpretations of the Federal Power Act are playing a very important role in how many of us are doing our jobs and how our markets are working jurisdiction. And then we're going to end We have a lot on our plate, and we're going to do it a little differently this morning than typically. I'm going to ask the four presenters to give their presentations in 10 to 12 minutes, and then instead of doing clarifying questions, because these are not really technical presentations, I'm going to try to engage them in a little bit of dialogue before our break, and then when we come back from the break, all of you

will have open season on our four legal experts here.

Speaker 1.

I was recently reading an article discussing energy issues that cited three major trends. The first is that technology is changing and requires more interstate electric infrastructure and investment. The second is that companies are getting bigger and costs are getting higher, necessitating consumer protection. And the third is that changes in the electric industry and technology are making markets more complicated and require more oversight.

Actually, that could be almost every article I read. But, in fact, those three conclusions were reached by the Federal Trade Commission in 1934 in their investigation that led to the Federal Power Act. And the Federal Power Act changed

the Federal Power Commission from a part-time gang of three cabinet secretaries, and it expanded the role of the Commission to include the regulation of interstate commerce and electrical energy; jurisdiction to review and establish just, reasonable, and non-discriminatory rates; and the interconnection and coordination of electric facilities and transactions such as mergers, asset sales, security issuances and so forth.

So what has happened? Those are basically the same things we do today, the same duties and many of the same tenets. We've just stretched and evolved them as what we regulate has evolved a great deal. How FERC determines something is "just and reasonable" has evolved from basically cost of service plus a reasonable rate of return to include market-based rates as using the level of competition in a market to determine if market based rates can be just and reasonable, and then more recently a lot of the cases coming from the regulation of competitive markets, energy capacity and ancillary services, which we talked about in the economic presentations yesterday, with the premise that if the rules established in the market are just and reasonable, the market can be counted upon to yield a just and reasonable result.

The Federal Power Act has been amended many times, but actually most of the amendments were pretty small, except for 1992 and 2005, and they didn't significantly change those core concepts of just and reasonable and public interest. They more added things such as reliability jurisdiction and enforcement jurisdiction. And from my observation, most of the things that are being debated on the Hill right now are more surgical than wholesale revisions to the Act.

There are really two key areas of tension that we see again and again. The first, federal versus state jurisdiction, and the second, the Federal

Power Act versus other areas of the federal government. Federal versus state debates are not new. They're built into the constitution in the way the government is set up and, of course, they're a part of the electric system, because everything we regulate is connected to something that state regulators regulate. Generation and transmission don't reach the customer without going through state regulated facilities. The Federal Power Act explicitly states that federal regulation extends to matters that are not regulated by the state and does not take away state authority over local distribution, intrastate transmission, and retail electricity. And almost everything we regulate is regulated by the states as well.

The first big battle was when FERC sets rates, what happens to them, and *Narragansett v. FERC* established the primacy of FERC wholesale rates and the need to pass them through 30 or 40 years ago. Those cases were decided. After the commission decided that the just and reasonable clause required open access to transmission, and Order 888 and the markets were developed. A lot of the more recent court cases have been around regulation of the markets.

The first big area of ongoing court cases is capacity markets. In 2009, *Connecticut PUC vs. FERC* held that FERC's authority to set wholesale rates extended to the wholesale capacity markets, even though they were intended to lead to investment in generation, which was directly regulated by the states. And more recently there are the pending third and fourth circuit cases coming out of Maryland and New Jersey that upheld the primacy of FERC's jurisdiction over the capacity markets against state laws that sought to stipulate specific bidding and market outcomes in the markets. And those are still pending petition for certiorari.

I would say the newest issue is how distributed resources are regulated. With the changes in technology, we're seeing that aggregated resources, even at the distribution level or the customer level, can behave in the aggregate like resources that trade on the wholesale market, and obviously the customer relationship, retail rates, and the electric distribution companies investment in conservation are all regulated at the state level. Where the issues have come is in the FERC's attempt to assert jurisdiction over the regulation of the pricing of aggregated demand response in the wholesale markets, and everyone in this expert crowd knows that four years ago, FERC decided Order 745, setting certain rules as to the compensation of demand response and wholesale markets. Last year that was vacated in a split decision by the DC circuit, and it is pending appeal to the Supreme Court. I can't unfortunately talk about what happens if FERC loses, because that's subject to motions that are pending at the commission, but I certainly think the case has the potential to be quite significant in determining how federal jurisdiction works over aggregation of distributed resources, which we're seeing more and more as a piece of the energy solutions for the nation. So it's a big deal in our little world.

And I was watching last night after the Supreme Court decision on the Affordable Care Act and one of the candidates (I won't stretch the Hatch Act by saying which one) was ranting about how this is not what courts should do. Courts are not supposed to decide what gets done. I was talking back to the TV, saying "No, that's exactly what courts are supposed to do!" [LAUGHTER] That's exactly how it's set up. So when the Supreme Court decides that, we will listen, because that's how it works.

The second big area I want to just mention is the Federal Power Act versus other federal laws. I

already said that everything FERC regulates is also regulated by the states in some aspect. Every company FERC regulates is regulated by a multitude of other federal agencies--the SEC, the IRS, the Federal Communications Commission in some cases, CFTC, and so forth. And sometimes those are independent areas that have nothing to do with each other, and sometimes they overlap, and sometimes there's even tension. Some of the early debates are with the NRC, and the Commission worked out regular meetings with the NRC to determine, once we got reliability jurisdiction in 2005, how did that work with the NRC safety and security jurisdiction. They do the rules of the nuclear plant, and then once it connects to the transmission system, there are very precise rules for when we take over. There's not a lot of conflict, but that all had to be worked out when it was new. Right now a lot more of the talk is about the EPA.

There is concern that the EPA's forthcoming carbon regulations will have impacts on the way the energy markets work, and I think they will. I think that because the carbon regulations are likely to influence resource choices, that could potentially influence rates, markets, and reliability rules. I do not see a conflict, more a need to work together, because once the environmental rules are set, then the markets have to adjust. But we have been working with them to make sure that we understand each other, and some see more conflict than I have just articulated, and we'll probably hear about that in the comments.

The third area I'll mention is the Commodities Futures Trading Commission. When Congress passed Dodd-Frank, they did not put in a perfect definition of where the Commodities Futures Trading Commission's jurisdiction ended and FERC's started, and that's been now decided in the courts and there will be probably many more

cases to come. In 2013, the DC Circuit in *Hunter* said that FERC should vacate that case. This Commodities Futures Trading Commission had exclusive jurisdiction over financial trading on energy instruments in the financial markets, and if it just related to financial markets, it wasn't a FERC case. Now, closer to home, the Barclays case, which is still going on, relates to FERC's investigating market manipulation in the energy markets done to affect a position in the financial markets. We think that because that relates to the energy markets that we regulate, we do have jurisdiction. The respondents have said no. They think CFTC has exclusive jurisdiction, and that's winding its way through the federal courts in California and will probably be the next significant case that starts to carve out how CFTC and FERC jurisdiction works together.

I think there's a lot of life left in the Federal Power Act. I think it's amazing how robust some of the words have proven to be against changes in technology and structure that could not possibly have been anticipated in 1935. So I feel honored to be one of its interpreters. Thank you.

Speaker 2.

I'm going to start by talking about a little bit about how we got from 1935 to where we are now. Let's start in 1935. The Federal Power Act was really the tail on the dog. The Public Utility Holding Company Act was regarded as a centerpiece of that legislation, and if you read Robert Caro's biography of Lyndon Johnson, there's some discussion in there about how in 1935 it was probably the most controversial part of the New Deal program. It passed the Senate by one vote. And the basic thrust of the Holding Company Act was to make utilities subject to local control. It was a movement in the direction of state regulation and local control.

The next decade or 15 years was devoted primarily to unraveling the holding company system that was in place in 1935. There were some distractions. There was a depression and a world war, but in the regulatory sphere, that was the focus.

Jump forward to the 1960s, and a great deal happened. The National Power Survey in 1964 was regarded as an important document in those days, and what it suggested was that the growth of the industry and the growth and scale of technology meant that we needed more inter-regional coordination, and that that would provide both economic and reliability benefits. Then in November of 1965 we had the Northeast blackout.

Now, there were a couple of judicial decisions in those days which, as you look back on them, seem to me to be quite remarkable. The first one is the *Colton* case in 1964. And there was also *Southern California Edison vs. Federal Power Commission*. And Southern California Edison was selling power at wholesale to a city located in Southern California, and the question was, who had jurisdiction over that sale. And the Federal Power Commission decided, and ultimately this was upheld by the Supreme Court, that since some of the electricity that Southern California Edison used on its system came in from out of state, particularly from the Hoover Dam, that therefore this sale by a company located in Southern California to a wholesale customer in Southern California was subject to exclusive federal jurisdiction.

We go forward to 1972 and the Supreme Court case *Florida Power and Light Company vs. FPC*, which was even more remarkable. Florida Power and Light had no interstate interconnections at the time. It was interconnected solely with other utilities in Florida, one of which, in turn, had an interstate

interconnection. The theory of the Federal Power Commission staff was that since a synchronous electricity grid operates on the basis where if demand is created or diminished in any place, it (in theory at least) can affect the whole grid, that all of this was in interstate commerce--that some of these electrons must cross state lines, and therefore this ought to be a jurisdictional sale. Now when you think about that, to use an analogy which is not quite on point but is not too far off, if your daughter goes out and opens a lemonade stand on the sidewalk in front of the house, the idea that lemons are a national market and that each time a lemon is squeezed that a lemon has to be grown in some place like California, and therefore that that lemonade stand is making sales in interstate commerce--that strikes me as quite a reach. The Supreme Court made that reach in 1972 and concluded that just being interconnected with anyone who is doing business in interstate commerce makes you interstate commerce. That led, of course, to the decision by people who live in Texas that avoiding interconnections was the only way to avoid this plague of federal jurisdiction.

So the pendulum from 1935 to 1972 was swinging quite strongly in the direction of federal jurisdiction over more things. A lot happened in the late 1960s as a result of all the things like the National Power Survey and the Northeast blackout. Big interregional interconnections grew. The Pacific intertie happened. The Keystone and Conemaugh plants and the associated transmission in PJM happened in the late 1960s.

We keep going forward, and then we have the Nantahala case, and the Nantahala case simply holds that where FERC has fixed a rate (then, again, the Federal Power Commission), a state has to honor that rate and can't squeeze the utility by not allowing it to recover that federal

rate. And it talked about the bright line between federal and state jurisdiction here.

We go forward in cases. We have, of course, the 1992 Energy Policy Act, and then, in the wake of that, we had New York suing FERC over the question of retail wheeling, and it was New York's view that Congress didn't have the power to direct retail wheeling in the Energy Policy Act. The Supreme Court held that in any place where transmission was unbundled from generation the Commission did indeed have that authority, and the only dissent in the Supreme Court said the case didn't go far enough, because you shouldn't limit this to unbundled situations, and FERC's jurisdiction ought to be exclusive over bundled and unbundled transmission to the ultimate consumer.

Now we go forward to what happened most recently and that's the *Learjet* case. There's some colorful language in the *Learjet* case. When you look at its facts, it's not a very extraordinary decision. As the court said at one point, even if you have a bright line between state and federal regulation, there are always going to be situations where state laws affect the federal side. And they mention as an example tax laws. That's absolutely right. And it works the other way as well. I think it's well recognized that states have the power to decide how much renewable generation utilities in their state should install. On the other hand, federal tax law has a great impact on the effectiveness of those policies. The idea that there are non-utility laws in states and non-utility laws on the federal side that affect the electric power business that is either state or federal regulated is not a very revolutionary idea. That clearly has to be the case. I think the way I would describe it is this way--that the bright line enunciated in *Nantahala* is a bright line between utility regulation on the state side and the federal side. It's not intended to say that either jurisdiction

can't pass tax laws and perhaps pass antitrust laws that have some incidental effect on what goes on on the other side of that line. Whether that's what the Supreme Court intended or whether the Supreme Court intended more, I think we don't know yet, and we may find out in the action that they take on the Maryland and New Jersey cases which Speaker 1 pointed out are still pending before the court on *cert*.

A few thoughts about that. I think that at least in the utility regulation area, bright lines are a good idea. I guess one pro of not having a bright line and of having concurrent jurisdiction is that at least lawyers in private practice will have to deal with a lot of uncertainty and will be quite busy. However, I don't think that's enough of an advantage to carry the day. The wholesale markets are very substantial now. They are still growing. Whatever happens with distributed generation, these wholesale markets are going to continue to be very important and to grow. They are highly competitive, and they involve people with a lot at stake. And games like that need an umpire. And the question of whether we need two umpires standing by first base, and then a discussion as to which of the umpires calls "out" or "safe," I don't think that's a very good direction in which to hit.

So I would be an advocate for the bright line here. I would I think support what Speaker 1 ended up saying. These New Deal pieces of legislation just have a way of holding up. They survive the test of time. This one has done pretty well at surviving the test of time.

Question: Can I just make one clarifying comment?

I hate to argue with you about something that both of us can go home and read, because that's empirical. But I think it's the other way. I think that the majority opinion hinges on the question

of whether you've found discrimination, and the dissent seems to suggest that if there's federal jurisdiction here to remedy discrimination, then there's federal jurisdiction and you have to assert it. That's the way I read the dissent, anyway. I see you shaking your head but we'll both go home and read it.

Speaker 3.

I've entitled my presentation "The Federal Power Act's Federalisms," and part of the reason for my emphasizing the plural aspect of federalism is to highlight that to the extent that there is a bright line in the Federal Power Act, this was not a choice that Congress made. Instead it was a doctrine that was developed by courts in the 1960s and 1970s, but in my view, at least, there are some court cases that point in the other direction as well, and the cases that find the bright line should not constrain FERC from considering other federalism approaches. And I'll try and discuss in my presentation today a couple of those approaches.

Before I get into federalism, though, I should mention that I really do think it's remarkable that the Federal Power Act has survived for 80 years. It's older than the Clean Air Act and the National Environmental Policy Act. It's older than the Administrative Procedure Act (APA). I teach administrative law, and the APA, of course, is revered by administrative law scholars. But the Federal Power Act has been around even longer. And it's even older than the Natural Gas Act.

So for 80 years, I think this statute has really withstood the test of time. It's outlasted other regulatory statutes that govern the communications industry, that govern the transportation industry, and for that reason, I think we should really be celebrating this occasion of the 80th anniversary of the statute.

When you look at the statute, it also stands out for being a framework statute. If we compare it, for example, to the Affordable Care Act, the statute that everybody is talking about these days, the Affordable Care Act is almost 1,000 pages. I think it's 906 pages in the House version of the statute. The Federal Power Act, even with all the amendments that have been imposed over time, including PURPA and the 92 amendments that have come year after year, is less than hundred pages. I think it's about 89 pages in the House version. And a lot of the features of the statute, from the language to the structure, provide flexibility in a way that doesn't get into the details of regulation to the same degree of many other regulatory statutes.

So it really is remarkable, and some of this remarkable adaptability has to do with the language, and I think terms like "just and reasonable rates" are a great example, and I hope we have the occasion to discuss the extent to which "just and reasonable" made rates language adopted under vertical integration with cost of service regulation of utilities able to evolve in its application by regulators to modern market conditions. It's a fascinating history and the way courts have given FERC the flexibility to do things with that language stands out. It's distinct from how courts have treated similar language in communication statutes and in transportation statutes. And although the Ninth Circuit recently reversed FERC on its interpretation of "just and reasonable" language in market based rates in the remand of the *Lockyer* case from a few years ago, I think nevertheless there's still quite a bit of flexibility that FERC has there that other agencies haven't been afforded under their regulatory statutes. And I think there's also quite a bit of adaptability in the structure of the statute and in the judicial doctrines that have been used to interpret the statute over the years.

So I want to move on now and talk a little bit about federalism, and the place to begin, I think, in thinking about federalism under a statute like the Federal Power Act (FPA) is where the Supreme Court reminded us yesterday we ought to begin in interpreting statutes like the health care statutes. Let's start with the purposes, the structure of the language of the statute. And if we look at the FPA, of course, the primary purpose of Congress in adopting Part 2 of the FPA in 1935 was to close the "Attleboro gap," that is, to authorize federal regulation of activities and transactions which states are incapable of regulating or lack the authority to regulate.

It was noted very early in the history of judicial decisions interpreting the Federal Power Act, long before 1972, that federal jurisdiction under the statute is to follow the flow of electric energy, which as we know as an engineering and scientific activity, not a legalistic or governmental task or determination. That was noted by the US Supreme Court in *Connecticut Power and Light Company v. FERC*. If we look at the statute and the way the statute allocates authority to federal regulators, the language, as I pointed out, is often very open-ended, "just and reasonable rates" being an example. But it's also attentive at times to respecting and preserving some state authority. In fact, the only instances that I could find where the Federal Power Act speaks clearly so as to provide for exclusive authority in its language are when it is speaking about state authority, not about the authority of federal regulators.

So if we look at federal authority under the FPA, Congress dispersed that authority in two different ways. In Section 201, it did speak to the direct federal authority that's delegated to the federal commission at the time (FERC today). Section 201(b) of Federal Power Act delegates to FERC the jurisdiction over the

transmission of electric energy and interstate commerce, that language that was interpreted in the *Florida Power and Light* case. This is the wholesale sales jurisdiction that FERC often relies on in regulating transactions. But there's also so-called "remedial authority," looking at Sections 205 and 206 of the statute. And Congress spoke in both sections to FERC's jurisdiction to regulate not only the rates themselves or the prices but to go further and to regulate practices, contracts, and regulations that affect these rates. This is the practices affecting rates jurisdiction issue that is in part at issue in the Electric Power Supply Association (EPSA) case before the Supreme Court right now. And at times, Congress again spoke very clearly so as to suggest FERC had no authority whatsoever, right? A good example of this is the savings clause that appears in 201(b) of the Federal Power Act, which states that FERC shall not have jurisdiction over facilities used for the generation of electric energy or facilities used in local distribution or only for the transportation of electric energy and interstate commerce or over facilities for the transmission of electric energy consumed by the transmitter.

So to move on to the federalism issue here, as I've suggested, if there is a bright line, that wasn't Congress's choice. I do think that if we look to the history of federalism in the statute as FERC has adopted federalism doctrines and as courts have discussed federalism doctrines, that there are two competing modalities or visions of federalism that have evolved, speaking roughly at least. The first modality is this notion of exclusive jurisdiction which is associated with those cases that endorse bright lines for jurisdiction and refer to the exclusive sovereignty of either federal regulators or state regulators. And notice this isn't only an exclusive realm for federal regulators. Once we define the realm of jurisdiction for federal regulators, at that point, the exclusive realm of

state jurisdiction begins under some interpretations of this view. In fact, that's the DC Circuit's interpretation of this view in the EPSA case.

But that view contrasts with another view that I want to highlight today. I'll call it "concurrent jurisdiction" or "shared sovereignty." This view sees some overlap between FERC jurisdiction and the jurisdiction of states. The fact that FERC might have jurisdiction of the statute itself does not preclude states from also exercising jurisdiction in ways that are coextensive with FERC's purposes and goal in its regulatory initiatives.

Before I get into the concurrent jurisdiction paradigm, I want to say a few words about the rise of exclusive jurisdiction. The basic point here is that this isn't in the statute itself. It's not in the language of the statute. Right? You can't find an allocation of exclusive jurisdiction to FERC in the language of the statute. Congress did not use the word "exclusive" or "plenary" in describing FERC's jurisdiction. It was courts that came along later interpreting the statute that created this exclusive field for federal regulation of the at the time vertically-integrated utilities. If we look at how this has evolved, it was early natural gas cases that first referred to the idea of plenary authority or exclusive authority, and not only natural gas. At the time, the US Supreme Court stated Congress had given plenary authority to regulate extensions of gas transportation facilities and the physical connection with the distributors as well as the sale of gas to them. That case is frequently cited to support expansive jurisdiction with respect to electric power, but in electric power you don't have similar certificate of public convenience and necessity authority.

In *US v. Public Utilities Commission of California*, a case that has to deal more with part

1 of the Federal Power Act than part 2 of the Federal Power Act, the Supreme Court also stated that Congress had interpreted the Attleboro case as prohibiting state control of wholesale rates and interstate commerce for resale. That case, too, I guess, stands for the proposition that if states don't have jurisdiction, it must follow that the feds have exclusive jurisdiction in that space. But it was not until the 60s and 70s the Supreme Court itself really embraced this strong idea of exclusive bright line jurisdiction under the FPA. In the *FPC v. Southern California Edison* case (1964) the court strongly endorses this idea of the bright line: "Congress meant to draw a bright line easily ascertained, between federal and state jurisdiction," the decision says. And in *Nantahala Power & Light Co. v. Thornburg* (1986) that idea of exclusive jurisdiction would be used to really clarify a federal doctrine, the "filed rate" doctrine, that precludes states from excluding costs that are approved in federally endorsed wholesale rates.

The "bright line" mode of interpretations sees the spheres of wholesale sales and retail sales as distinct. And I think there's a lot at stake if this is the predominant view of federalism under the Federal Power Act. This bright line approach, what you can find in these cases from the 60s and 70s, has been used by federal courts to support the idea that states do not have the ability to adopt incentives for wholesale capacity. These are the capacity cases out of the third and fourth circuit pending on *cert* before the US Supreme Court.

And the flip side of this paradigm, this vision for federalism, is to view the realm of state authority as being exclusive as well, right? It's either/or, right, with respect to the bright line and, of course, the DC Circuit in the *EPSA* case suggested that demand response is exclusively a

state activity because it falls on the retail side of the so-called bright line.

I want to suggest, though, that that bright line has fallen into some disfavor, certainly before the US Supreme Court, and I also want to suggest that that's not inconsistent with the Federal Power Act, its history, and some of the earlier cases under the Federal Power Act. If we look to post-restructuring cases, *New York v. FERC* itself recognized, in quoting the DC circuit opinion that upheld Order 888, and I think referring to the evolution of wholesale markets in particular but also to different state approaches to address vertical integration, that "Changes in the landscape have called into question whether the electricity universe is 'neatly divided into spheres of retail versus wholesale sales.'" That's the distinction on which the bright line depends.

The majority opinion in the *ONEOK, Inc. v. Learjet, Inc.* case written by Justice Breyer and joined by five other justices, suggests that the quest for a "clear division between areas of state and federal authority" is a "Platonic ideal" that does not describe modern natural gas markets. I would submit that modern electric power markets are even a little more complex in terms of their technical and engineering characteristics as well as their economic operation than natural gas markets, and perhaps we might see the same view applying here.

So if we take this idea of concurrent jurisdiction or shared sovereignty seriously, we'd have a very different visualization of authority between the state and federal regulators. FERC may have some exclusive jurisdiction over wholesale sales but it's not completely plenary. There's an overlap. States may have some jurisdiction over retail sales and retail activities, but that, too, is not exclusive jurisdiction. There's an overlap, and the question, I think, that remains to be seen

is whether the US Supreme Court will consider demand response or capacity incentives as falling into the overlap area or as falling on one side or another of that area.

This idea of concurrent jurisdiction is not new. It's not something that has only evolved in competitive markets. There's a lot of history behind the Federal Power Act, and if we look at the legislative history, I would submit there's as much support for this in the discussions before Congress as there is for the idea of the bright line. Just to give a few examples, Commissioner Seavey testified before the House on the original bill that was later amended and became the Federal Power Act suggesting, "The new title II of the act is designed to secure coordination on a regional scale of the Nation's power resources and to fill the gap in the present State regulation of electric utilities," but continues, "It's conceived entirely as a supplement to and not a substitute to for state regulation." The bill that actually did become the statute was reported to the Senate Committee on Interstate Commerce and that report suggested that the declaration of jurisdiction in the statute in Section 201 was designed "to assist the States in the exercise of their regulatory powers," and before the Senate, too, it was stated in a report that the purpose of the bill is "to aid the State commissions in their efforts to ascertain and fix reasonable charges," and "to be a complement to and in no sense a usurpation of State regulatory authority..."

There are some earlier precedents, as well, that support concurrent jurisdiction. For example, *Connecticut Light & Power Co. v. FPC* (1945) was, I think, one of the earliest cases decided, and it says that "the fact that a local commission may also have regulatory power does not preclude exercise of the Commission's functions." And even if we look at some of the modern cases that use language gesturing in the direction of plenary jurisdiction, they, too,

recognize that FERC's jurisdiction here does not completely usurp the ability of states to do things. The *Conway* case (1976) is a good example.

So, one of the objections to this idea of concurrent jurisdiction is it's inconsistent with the history. I've tried to convince you that that's not the case. Another objection is it's inconsistent with the language and structure of the Federal Power Act. I see nothing in the language and structure of the Federal Power Act that precludes it. I think a final objection I've heard from time to time is that, "Well, if we allow concurrent jurisdiction, there are really no constraints, right? It's just mush. Federalism becomes this mushy area where there are no limits on what federal regulators can do at all." I would submit, though, that there are still some constraints on FERC. There are still some constraining principles, and those derive from the language of the statute. I'd be happy to talk about some of those during the broader discussion, but if we look at language such as "practices...affecting jurisdictional rates," we can find constraining principles. If we think about the purposes of the statute, such as the *Attleboro* gap, I think there, too, we can find constraining principles. And I also think there are some constraining principles in the savings clauses in the statute, such as the savings clause in 201(b), or the savings clause in the provisions of the statute having to do with retail with transmission.

So just to briefly conclude, outside of a few areas where jurisdiction is exclusive, and there probably are some, Congress did not define a bright line in the FPA. That was created by courts. Instead, Congress delegated to FERC discretion to meet statutory objectives by adapting its federalism approach to market conditions, and I think the most recent cases decided by the Supreme Court in a post-

restructuring era gesture in the direction of giving FERC some flexibility with respect to its federalism approach.

I would submit that part of the reason the FPA has remained relevant 80 years after its adoption is that this framework gives FERC a lot of flexibility in addressing challenges in modern power markets, because it doesn't endorse a particular federalism model. Of course, with that grant of authority, FERC has some responsibility, too, but it's FERC that I think can probably do the most in defining the bright line, not courts, in my view.

Speaker 4.

First, I just wanted to say that I'm honored to be here with this panel to celebrate the 80th birthday party of the Federal Power Act, and to note that I celebrated the 70th birthday of the Federal Power Act at a celebration at FERC with, actually, many of you. And it's amazing that it's been 10 years since we marked that 70th milestone. But I guess time goes quickly when you're having fun, and I suspect most of you agree, since we spend a lot of our time working with the Federal Power Act, that there's not much more fun you can have than that. Secondly, I'd like to disclose right at the start that I'm a huge fan of the Federal Power Act. Why? Well, I think it boils down to something very simple. When Congress created the Federal Power Act in 1935, they gave it a close to perfect bone structure. And with the help of the courts, it's allowed the statute to evolve into a pretty elegant law.

So let's talk about that bone structure. If you look at the provisions of the Federal Power Act, to me there are four that really make it what it is. First, Congress was very, very clear about where federal authority lies. Congress said authority lies with the Commission for rates and charges and classifications of public utilities for electric transmission and wholesale electric sales

beginning and end of story. Very clear. I think that's a pretty bright line. Second, Congress told federal regulators what the goal was without being prescriptive, without telling federal regulators how to do it. Congress said the goal is simple: just and reasonable rates and no undue discrimination. Perfect. If you doubt whether that was a good way to go, for those of you who have had experience with the initial statute that set up the California ISO, you can see how sometimes legislatures get it wrong when they try and legislate all the little details about the best way to do it. So having a goal, just and reasonable rates and no undue discrimination without prescription, is perfect.

Then around the core authority, Congress put a penumbra. As constitutional scholars will tell us, it's helpful to have a penumbra. So Congress gave a defined penumbra around the core authority, around rates and charges for electric transmission and wholesale electric sales. At FERC we would call it FERC's "affecting authority." In Section 206, the statute said that FERC's authority extends to rules and regulations, practices and contracts affecting the rates and charges and classifications of section 205. Having a penumbra is helpful, and has been helpful to FERC as it's tried to keep up, and I think has kept up, with changes in the industry. And FERC has used its "affecting authority" quite effectively.

Fourth, and also importantly, Congress didn't leave that penumbra out there to just diminish off into the sunset. Congress put boundaries on the affecting authority. Specifically, for example, Congress said, "and your authority does not extend to those matters which are expressly reserved for regulation by the states." So you have a core. You have a penumbra. And then you have a boundary. As a state regulator, in particular, I appreciated that. And that's maybe not unique in federal legislation, but

certainly not ordinary. I suspect this is because the states came first. They were regulating the electric industry before the federal government got involved, and Congress recognized that authority and enshrined it in the statute. As a state regulator, I appreciated having a bright line and knowing that if it had to do with retail sales in the distribution system, I could regulate it. And if it had to do with transmission and wholesale sales, I probably couldn't.

This construct has been used very effectively by FERC in addressing not only the day-to-day problems that have arisen over 80 years in the electric industry but also the more urgent problems. And we've seen that the courts have been deferential to FERC in those situations when FERC has acted at the limits of its authority, for example, Order 888, when it opened access to the transmission system, and arguably Order 1000, when it provided for regional transmission planning. The courts were deferential to FERC as it used its affecting authority, I think in large part because the courts understood that what was happening was resulting in unjust and unreasonable rates and in discrimination. I think the courts understood that FERC was the best if not the only entity in a position to craft a solution. And the courts were happy with the solution FERC crafted.

So it's not surprising to me that we have an 80 year old statute that has as previously noted only been amended on occasion and then only strategically. And I think it will stand us in good stead for likely another 80 years. And if we look to Congress right now to see what is Congress talking about doing as it's talking about amending energy legislation and giving us new energy legislation, really Congress is not looking to amend the Federal Power Act. It's concerned about the Natural Gas Act. It's concerned about the changes in the oil industry and the natural gas industry and whether the Natural Gas Act is

up to the job, but it's not looking at any significant changes to the Federal Power Act.

Moderator: First of all, that was excellent all four of you. Thank you very much. I'm going to start with this penumbra concept that you just raised, because it strikes me that the penumbra might actually be the area of intersection of the two circles that Speaker 3 talked about--the area where there is an opening for cooperative federalism, or at least, certainly, not a bright line. I take what you said, Speaker 4, as being that there's a bright line of what the states can't do and a bright line of what the feds can't do, but there's this intersection area, the penumbra, of affecting authorization. So I'd like to throw that out to all four speakers to give your take on that and to apply that to an issue that I have particular concern about, which is the treatment of distributed generation and where distributed generation now falls within these different lines or the intersection of the circles.

Speaker 2: I didn't think that Speaker 3 was that extreme in his remarks. I guess there were a couple of things that Speaker 3 said that I would want to comment on in this area. Speaker 3 said that this idea of the bright line really didn't originate with Congress in 1935. It originated with the courts. It actually originated with the courts in the *Attleboro* case. That's before the Federal Power Act was enacted, and it said states can't do this because they were intruding upon interstate commerce. That led then to the statute, the Federal Power Act. So the Federal Power Act is not the seminal document here.

On the question of distributed generation, certainly it's hard to argue that anybody ought to have authority over every aspect of distributed generation. I think a strong argument can be made that to the extent that distributed generators are selling in to the grid, that is subject to federal regulation. The question of

when distributed generation should be permitted and how that interacts with the retail rate structure looks to me as though that's probably on the state side of the line.

Moderator: OK. So it's a mix. Anybody else have a take on that?

Speaker 1: Well, I guess I'll try. First of all, I want to say that I really appreciated Speaker 4's remarks. I must have said a hundred times that FERC really has pretty limited authority but within that authority FERC actually has authority. FERC just doesn't do reports and studies and things. It actually gets to do something. So you really explained it. Now I understand what I've been saying.

I think I said when I spoke that the nature of the electric system and the nature of the products and services that are part of the electric system are such that by definition there are going to be aspects regulated by both the federal government and the state government. I think it's very hard to point to anything where you say, the federal government is exclusive, exclusive, exclusive. I mean I'd say hydro licensing comes close, but even there, there's a myriad of other agencies that are weighing in, and so forth. So I think there are clearly aspects of, in my view, distributed generation that are appropriate subjects of federal regulation. Transmission interconnections into the high voltage grid, wholesale market participation and the rules around that, I think, are part of interstate transmission and wholesale sales. There are clearly other aspects that definitely should be regulated at the state level. I talk all the time about the need to cooperate with the states, and the fact that we need to work together, and how the things we regulate are so intertwined. I think what puts me off about some of the verbiage around this is that I think of some big panel of like half state and half federal

representatives, and everyone votes, and all that could get quite unworkable, and I don't think that's what anyone's really talking about. But both state and federal sides are going to regulate aspects of the same thing, and I think that's only getting more so as the technology is making distributed things operate like centralized things.

Speaker 3: Sure. I don't disagree with your comment about *Attleboro*, Speaker 2. I think that's a good observation. At the same time, I think we ought to be wary about the precedential impact that a Lockyer-era judicial interpretation should have as a constraint on modern courts and the modern jurisdiction of FERC. In fact, I would argue that Congress didn't fix in place FERC's jurisdiction in 1935, but instead it was endorsing the general principle of *Attleboro* that we can have regulatory gaps. We just need to assess whether those gaps exist and use FERC's jurisdiction to address the problems that arise within those gaps.

I also agree with everything you said about some of the significance of having an ability for federal regulators to step in when things are affecting wholesale markets. My own view is that's a decision that was delegated to FERC and that FERC ought to be making that determination, not federal courts, and insofar as FERC is classifying something as a wholesale sale given its expertise and understanding of the operation of markets, I think it would be entirely appropriate to exercise authority in that context. But, again, I don't think that authority should necessarily be exclusive. So that's my general opinion.

Speaker 2: I'm not sure how you can do this without the federal courts. FERC doesn't have the authority to enjoin people. So if a state is doing something that intrudes upon federal jurisdiction, I think the courts are the ones who have to resolve that.

Speaker 3: I don't disagree. There are going to be jurisdictional issues, but these jurisdictional issues are based on constraints in the statute, not on some theory of federalism.

Speaker 4: I'd like to reverse engineer the moderator's question. Let's take as a given that you have distributed energy resources. Is there a problem with allocating jurisdiction around them the way the Federal Power Act seems to say we should? In other words, if there are distributed energy resources and they're interconnected to the distribution system, they are probably within state jurisdiction. If they are selling power at retail, that's state jurisdiction. If they want to sell power into the wholesale market, at least with respect to the sale transaction, it sounds to me like it should be federal jurisdiction. So I guess I don't see a problem. I don't see that the interconnection of more distributed resources in our grid, defined broadly to include transmission and distribution, and leaving that primarily to the states presents a problem. And, practically speaking, the implication of federal jurisdiction is that you're probably going to have one way of doing it. Not that FERC always mandates one way of doing it. We look at the RTOs and because standard market design failed, we see that they do it their own way. But by and large, if you have federal jurisdiction, there's going to be one way of doing it, and that's what the *Attleboro* court said. In a sense, that's what we want. But do we want one way of integrating distributed resources into the distribution grid? Or are we content with allowing states to do it the way each state sees fit?

Moderator: That actually leads to the next question I was going to ask, which goes to the consideration of local consumption and local impact. I'm not an expert on these cases, but I know we have experts on the cases, so I'm going to throw them out. I think it's the *Kassell v.*

Consolidated Freightways case in 1981 and the *Southern Pacific v. Arizona* case in 1945 which I think both brought up the concept that states have a wide scope of interest in matters of local and state concern, as long as it does not materially restrict the flow of commerce across state lines.

So there is this concept that there are state interests, and in particular what I'd like you guys to address is, as we look at the 111(d) issues and the challenges that are going to come to states to have to potentially craft approaches to comply, where is that line of whether or not states can take action based on their state interests, or is that always going to be trumped by impacts on interstate commerce? Where is that line and how does the state interest play into that?

Speaker 3: It's a great question. It's a complicated question, because there's both a constitutional part to it and a statutory part to it. The constitutional part has to deal, of course, with whether Congress has the authority under the Commerce Clause of the Constitution, and that authority, I think, is pretty expansive. It's well established. There may be some outer limit on it, but I honestly don't think any of these questions really border on that, although I know some who believe, for example, that Congress doesn't even have the authority to give federal agencies the ability to preempt state eminent domain powers. I think those views are at the extreme and not at the core of what most legal scholars think.

The more difficult issue, I think, is under the Federal Power Act, what's saved for the states under the statute? What powers are saved for the states? And there are several parts of the Federal Power Act that speak to the preservation of state authority. It begins in Section 201(a), but that language has been interpreted to only be a policy declaration and not a legal line that Congress

was actually drawing. It's a policy declaration that where statutes are ambiguous; maybe that means you put the thumb on the scale in favor of the state. The more explicit savings clause appears in 201(b) of the statute, and the question there is about the type of facility (distribution or generation). It doesn't refer to retail sales.

And then, finally, there are reservation clauses that relate to transmission, and we can get into that. It's pretty clear Congress did not intend to order retail wheeling. It didn't step in that direction. So there are places where Congress has spoken clearly to that, but a lot of it is left to ambiguity, and is left, I think, to the policy choice of FERC and how FERC exercises that policy choice. In my view, it would just be subject to arbitrary capricious review and maybe would put the thumb on the scale in certain instances in favor of the states, but it would be incumbent then on the agency to come up with the policy choice to answer the question Speaker 4 asked. What do we want as a matter of policy in this context?

Speaker 1: Well, one of the interesting things about 111(d) is that that's under the Clean Air Act, not the Federal Power Act. That's an example of a statute that didn't reserve any jurisdiction to the states, at least not explicitly.

Moderator: Right. And I guess by raising this, I was just thinking of the approaches that the state regulatory commissions may want to approve to try to meet those objectives, and the fact that they could then cross these state-federal lines.

Speaker 1: When I try to unpack the questions raised by the states now coming up with the State Implementation Plans for 111(d) and thereby making energy decisions that are going to be regulated at the state or federal level under the various energy laws, I really see a significant distinction for states that are not in organized

competitive markets and still are vertically integrated in large measure (although many things are regulated by FERC even in those states), and where certainly the selection of generation and the paying for it is done pretty much exclusively by the state regulators. In contrast, in the states that are in organized wholesale markets, the regions have chosen to use a competitive structure in certain respects to decide what gets billed to compensate generation to dispatch generation or other resources, and I think it's inevitable that for the states that have the regional organization that's calling for those resources, this structure has made some things wholesale or made some things more federalized that would not have been otherwise. But those regions only exist in the long run with the good will of the states. If the state says, "This market is not working for me. I don't want to be in a market. I want to take my ball and go home. I don't want to be part of an RTO anymore," they can separate. Then the market won't exist. But as long as it does exist, and as long as it is trying to use a regional structure to decide what gets billed, we're going to have to try to do it fairly. So I think that's where the rub is.

Moderator: All right. So I think what I'm going to do is just ask if any of you have any final thoughts to leave the group with and then we will take our break and then everybody can come back with the hardest legal question you can think of our expert panel here.

General discussion.

Question 1: First, thanks to the panel for your excellent presentations and Happy Birthday to the Federal Power Act. It never occurred to me that I should love the Federal Power Act, but after Speaker 4's presentation, I'm going to think it over. That was pretty impressive.

I want to ask about an idea which is implicit in some of the discussion but I don't think was made explicit in terms of how this plays out, and it goes with what I think lawyers refer to under the general term of deference. I'll use as an example the worst decision I think that FERC ever made, which was the deference to California in creating the California Power Act's CAISO – PX split, and the justification for it was, "Well, they really wanted it." So that's sort of my summary of that argument, even though FERC knew at the time, and we saw subsequently, that it was conceptually a really bad idea.

Now we fast forward and we think about the Clean Power Plan Section 111(d), and there are these organized markets that Commissioner LaFleur talked about that cover 70% of the load out there, and we've got 50 states that are coming up with State Implementation Plans. It would be remarkable if it turned out that we don't end up in a situation where somebody comes in and says, "We want the RTOs which are under FERC jurisdiction to change what they're doing and do something completely different in the design of their markets in order to make it easier for us to implement our version of our state implementation plan here." And now FERC looks at it and says, "This looks like California all over again. Should we defer, because they really want to do it?" Or if there's an alternative which would still comply with the environmental objectives but which would be more compatible with the mandate that FERC has and RTOs have, should FERC say no, or what should we do here? What is the extent of deference? What are the limits of deference? How does it play into all of this Federal Power Act stuff?

Speaker 1: It's a great question. I think if there's a simplification of the question, the premise is somehow that it's FERC and the state. The state

wanting to tell PJM, for example, to do something different with the way they run the market or dispatch power, and FERC deciding about that. I suspect there are probably going to be things that states choose to do in their 111(d) plans that will require adaptations, just as now PJM or ISO New England model incorporates limits on plants and when they can run and what the thermal rules are. I know that back in New England, we could only run Brighton Point until the temperature of the Bay got to a certain level, and then you had to back down some of the units, and there are things like that embedded in the dispatch order and the dispatch stack already, and I think that, in large measure, the first job is going to be for the RTOs to try to adapt to the states.

If there are things that just cannot be adapted without doing too much damage to the way the wholesale structure works, then I think it will come to FERC, and it's not in FERC's authority to tell anyone to violate the Clean Air Act, but I think FERC has to listen. FERC is mainly governed by the Federal Power Act in deciding what is going to be just and reasonable. But I hear a lot of people talking about, "Oh, it's going to be environmental dispatch." I personally don't think that, because environmental dispatch to me is you get rid of the cost element entirely and you dispatch the fleet by emissions only. I think it will be cost-based dispatch the way we have now. Security-constrained economic dispatch, but with different and even more complicated limiters on when certain plants can run. That's going to be a lot of work for the RTOs. I don't know if that was a complete answer. I'll let someone else try.

Speaker 2: To the questioner, your California example is, of course, on point, and FERC eventually decided they needed to get involved in that, and they swung the pendulum all the way and tried to replace the board of the

California ISO, as you may recall. The DC Circuit said, no, you can't do that.

I think Speaker 1 expressed the framework well. When those things come before FERC, I would hope that they would decide it on the merits.

Question 2: No, thank you. This is an excellent panel, and I want to take the inspiration from the last slide of the description of the panel which asks us to look at what lessons we can derive from 80 years of FPA history that will help us move forward. So with that in mind, I'll ask a short question and then back up with a couple quick observations while you're thinking of the answer. And the question is, should Congress get involved in trying to rework this and legislate in this area?

I ask that now because there are already moves afoot. Senator Heinrich introduced a bill in the Senate last year to overturn the DR case even before the Supreme Court heard it. There are rumblings of other people doing that.

And let me add a couple of quick observations. One is, the one statute that was not mentioned by the panel (well, it was mentioned briefly but not with reference to this issue) is the Energy Policy Act of 2005, which in two respects is the last time, I think, that Congress truly tried to do some line-drawing here, and in the case of demand response actually said, "We want the states to cooperate. The Secretary of Energy should provide technical assistance." And the NERC reliability context obviously did not give the Commission plenary authority. So, arguably, at least the last two times that Congress has legislated in this area, they have sort of not been on the side of giving a whole lot of authority.

And then the last point, and this is the part that frankly gives me great pause. While there's no legislation pending that would alter the

fundamental 201 jurisdiction, if you look at the House and Senate drafts and the bills that are in, it looks a whole lot more like Obamacare, regardless of what you think of Obamacare, than it looks like the bone structure and nature of the Federal Power Act. And for those that aren't familiar with this, if you look at the Senate bill, they would have RTOs doing financial analysis of every plant on a unit by unit basis, and the list goes on, and there's the same structure in the House, where instead of looking at basic principles like "just and reasonable" and giving the responsibility to the Commission, instead Congress has this laundry list of contradictory goals and objectives for the capacity markets and the energy markets and how long the units should run in order to consider base load...and the list goes on.

So I guess back to the question. Knowing the way the Congress has been going lately, whether it's in '05 or even more recently, is this something that the courts need to decide, regardless of what the Supreme Court does? That's the final answer, as the game show would say? Or is it wise to even be thinking about having Congress try to get back in and rearrange this? Or does that give you a lot of heartburn that Congress would get it wrong?

Speaker 3: The latter, heartburn. I'm more of the view that in the design of the statute, we designed it so that federal jurisdiction would follow the flow of energy, which, again, is going to flow based on technological, engineering, and, to a degree, market characteristics, not based on some sort of legalistic or governmental task, especially one imposed by Congress, and if we look at the history of amendments to the Federal Power Act, there have been a large number of them, and some of them do attempt to impose fixes, but most of the amendments, I believe, have been more proactive in terms of

authorizing federal regulators rather than limiting what they can do.

So in that sense, I guess the history might make me think Congress would be more pro FERC with respect to managing the markets, but I think the question you raised does highlight that the possible fear here is that you attempt to micromanage and you impose the wrong limitations, or you just attempt to reverse some circuit court opinion you don't like, or something like that. I don't think that would be a good Congressional fix to the Federal Power Act.

Speaker 4: I tend to agree. There are a couple of things that if I were the queen of the world Congress could do. I think the section 216, the backup transmission siting provision, has not proven to be workable. If they want to do anything on that, that could benefit from clarity. I don't think they're going to. I would not be expecting that. I think more clarity around CFTC versus FERC might be useful. I don't expect that to come, either.

I think some of the House proposals, the discussion drafts, that would precisely micromanage aspects of the capacity market, are like the early California laws Speaker 4 spoke about, the micromanagement type of legislation, that the minute that it gets passed, you have to amend it because something is so wired in that shouldn't be. So I wouldn't welcome that. I think we're better off with the bone structure.

Question 3: I'm going back to the issue of distributed energy resources. At the 30,000 foot level I seem to hear consensus about the retail sale of the product, and the interconnection with the distribution company being pretty much obviously more of a state regulatory issue, and that when some entity attempts to aggregate and sell this product and get paid for it in the

wholesale market, you've triggered the FERC and RTO type jurisdiction. But I wondered if you know about or can comment on what I understand to be some legislation under development by Senator Angus King's office in which he's publicly distributed fact sheets which make it appear that he's trying to amend the PURPA to make the right of interconnection for distributed energy resources something akin to a qualifying facility or QF type of regulatory regime, and whether you could comment on the implications of doing that in light of the typical jurisdictional issues that are likely to arise at the federal level by going down that path.

Speaker 3: I gather part of the impetus for this is to bring within the realm of FERC jurisdiction the price—specifically, that PURPA language, “shall not exceed avoided costs.” So, I mean, under PURPA, at least under the FERC's current interpretation of PURPA, that would suggest some sort of ceiling on the prices that could occur under net metering statutes for these kinds of transactions. I don't have much of a view.

Moderator: I think that's just proposed legislation at this point.

Question 4: My question is about FERC. The Federal Power Commission was an economic regulator back in the day of contracts, and now it's become an economic regulator of markets, without any real new instruction from Congress on how it should go about doing that, for the most part. And so the key just and reasonable, not unduly discriminatory language, even though that was written for contracts, it's now a standard for markets, and I'm wondering if you have views on what that means in the context of markets, because some of the recent lawsuits that have come up (involving capacity markets and other issues as well) have to do with the fact that there are these sort of out market subsidies that are now market distortions, and now we

don't have perfect markets, in some sense, and therefore perhaps we should view these things as not just and reasonable, and as distorting the market.

And there are any number of other state policies that potentially could fall into this bucket of potential market distortions. So I'm wondering, how much room is there within the just and reasonable framework and within the not unduly discriminatory framework to allow for state policies that are inevitably going to affect the market but still perhaps be viewed as just and reasonable?

Speaker 1: Well, I believe somewhere in your question you used the word "perfect" or said that markets are not perfect, and I do not think market rules are perfect. I take great comfort from the word "reasonable," which to me implies a level of judgment. But I think that you put a finger on one of the significant issues that the markets have dealt with, which is, for example, state renewable portfolio standards and how they interplay with the capacity markets. Different markets have had different levels of adaptation or non-adaptation. Different markets have done it differently. There are a lot of things that might be seen as subsidies that are brought into the cases all the time, and I think we need to really use our best judgment about the words "just and reasonable."

Speaker 2: I agree with that. I think that there are also distortions that don't come before FERC, and the Maryland and New Jersey cases are examples of that. And if something comes before FERC, I have a lot of confidence in their ability to sort that out, based on the just and reasonable standard. You still need to be able to respond to things that are extra-FERC that go on and that can really affect the markets that FERC is regulating.

Speaker 4: I agree with Speaker 2, and I think that, well, we'll see whether the Supreme Court grants *cert*, but the third and fourth circuit decisions do a pretty good job of at least explaining how the courts view the law about that. And the courts give states a lot of leeway to do things that affect the markets indirectly, but not if they directly target FERC's wholesale markets and attempt to set a price that would not be the price set by the markets. So I think the third and fourth circuit has given us a pretty good clear line. There might be some debate about what's in there, but we have a pretty good blueprint.

Question 5: I want to talk about Speaker 3's circle diagram that overlapped two circles to illustrate this concept of concurrent jurisdiction, and I took the point to be that there's some concern about that model, or the overlapping gray area, because the gray area can expand wider than maybe what was intended. But my question is actually more around asking the panel to talk a little bit more about what happens when you're actually in that sort of gray area. Who is deciding what? Does someone have priority? Are you trying to agree? What happens when you disagree? So how does that work when folks agree that you're in that gray space?

Speaker 3: That's a great question. I think within that gray area FERC has a lot of opportunity to be creative, as do states. There's a wide array of different possibilities. There are cooperative federalism regimes where the federal government might take the lead. There are bottom up approaches. But I think all these are possibilities, and my own view is that we ought to be focused on having a discussion about what those possibilities are, and that FERC has some tools available to it where it could be very proactive, for example in working with the states and maybe even implementing standards or systems that would work in a cooperative

federalism-type manner with respect to the states. It could do this through Notice and Comment rule-making, for example. So I just think there are a whole range of possibilities there.

One possibility is that FERC could articulate basic goals and purposes and values that matter in our state markets and allow states some flexibility to tailor their particular regulations to those values and purposes. Another possibility is that FERC could adopt the approach that we ought to have a uniform federal market and could adopt a bright line, but my own view is that when it does so, it ought to do so in Notice and Comment rule-making or through a very transparent regulatory process.

Speaker 2: I'm very skeptical of fast-moving, high stakes games whether they stop to talk over the rules after each play.

Moderator: I just wanted to respond to that. At least if you have the umpires making a call when it's happening, it's better than having to replay the whole game two years later, and it seems as though we're coming to a point, whether it's with respect to demand response or distributed energy policies, where states have been proactively trying to come up with solutions either to have a more sustainable energy supply, to deal with affordability, or to deal with security of supply, and to have these challenged and then wait for the long court process. But these all create a lot of uncertainty, and I think that if we did have a method where we could collaborate and come to a better understanding of what was in each other's jurisdictions, that that might actually make the markets work more efficiently. I don't know how to do it.

Speaker 1: I would just like to say I do think there are areas where FERC does work in an overlapping way with the states. For example,

the small generator interconnection agreement amendments FERC did a couple years ago with the Notice and Comment on how much solar you put on a feeder, where there's a FERC standard, and states can have alternative standards, and it was very collaborative. And so there are definitely things like that. I guess I think in many cases, though, we have to ask ourselves what's really in the place where the two Venn sets overlap. Is it really gray, or if you look closer, is it a mosaic of black and white that kind of appears gray? And I think that in the way it's done now, it's a little more of a mosaic of black and white, with the courts deciding which one is which.

Question 6: My question is about FERC authority, deference to FERC, and also changing circumstances on interstate transmission siting and transmission needs. There's already been a reference to the fact that backstop siting authority has not really worked. But I guess the question is, since we're talking about the Federal Power Act, do you need it? Can you use the existing broad provisions of the Federal Power Act in light of changing circumstances? So let's say the Clean Power Plan gets implemented, and we need to bring more renewable energy into the system. Technology doesn't develop in a way that we can do it all through a battery, so we still need long distance transmission lines to do it. And if states are standing in the way of that through new rights of first refusal that have been enacted since Order 1000 or other sorts of limits on the merchant transmission companies that would build some of those lines, does that give FERC independent authority to take a different position on transmission siting? There might be lots of political reasons not to exercise that authority, but I guess a question is, does that authority exist in light of the Federal Power Act and in light of the deference that courts would presumably give to FERC if those factual

findings were made on either discrimination or changing circumstances in the electric grid?

Speaker 3: Just to clarify, you're not arguing that FERC should preempt the actual siting decision, but that FERC should preempt the decision about a state about ordering the market or limiting who can get in to the market in the first place?

Questioner: You could think about it either way.

Speaker 2: Maybe it just hasn't come to my attention, but I haven't seen situations where utilities who have rights of first refusal are refusing to build lines that regulators want them to build. The problem that led to the earlier effort to extend federal jurisdiction over transmission construction was states who didn't want those lines built when utilities often did want to build the lines. And FERC never found a way to get around that and to require states to get out of the way and to let those lines get built.

Speaker 4: Well, I think that goes back to the creation of the statute and Congress's decision to reserve to the states their jurisdiction. Obviously, historically, they've had transmission siting jurisdiction. Unless Congress decides to give that siting jurisdiction to FERC, I don't see how FERC could interpret the Federal Power Act to allow it to happen, and I think it would be political suicide to do that. I suppose there might be a constitutional argument that a state decision not to site would be an undue burden on interstate commerce. That would be a way to accomplish it, but I don't personally see room in the Federal Power Act to go against a state decision not to site a transmission line.

Speaker 1: I agree with Speaker 4 on siting. I think it would be a heavy lift with section 216 in the 2005 Act to assert federal siting authority

directly. But part of your question wasn't about siting. It was more about federal preemption of who gets to build transmission, and so forth. In Order 1000, FERC said that it was not intended to preempt franchise laws or states' right of way authority. That was the judgment of several the Commissioner that voted for Order 1000, and that's been upheld. Of course, the interpretation of Order 1000 is itself pending before courts in several appeals of the compliance orders, but the Order itself is now final and no longer subject to appeal. And so it was not intended to preempt. I know Chairman Bay has written a recent dissent or two on whether the right of first refusal actually might be unconstitutional. If those dissents were to become the law of the Commission, that would give a broader authority over the rights of first refusal than is currently the law of the Commission, which is Order 1000.

Question 7: This has been a great panel, and I want to ask you to look forward to things that may happen between now and the 90th birthday of the Act and think about, in particular, a couple of areas in which I could imagine the exemption for state jurisdiction over distribution facilities potentially coming into conflict with areas of federal jurisdiction. The first has to do with distribution system operators, and we have had the luxury that markets to date have been at the transmission level, where FERC has jurisdiction over transmission. But if we have markets at a distribution level, in which there are parties engaged in transactions that could be considered wholesale, but those markets are really operating through distribution facilities, how do you begin to think about state jurisdiction over distribution facilities versus markets that include wholesale transactions?

The second area where FERC doesn't have plenary authority but certainly has important authority is the reliability area, and one can

imagine a cyber physical attack on a distribution facility that affects the reliability of the bulk power system but is not included within existing NERC standards on reliability of the bulk power system. How might that get resolved in an era where these threats are becoming potentially more and more serious and more common?

Speaker 2: Let me try the first one. The second one is really a hard one to ponder. With respect to the first question, I like the way the Federal Power Act is structured. A wholesale sale is under FERC jurisdiction, even if the wholesale sale takes place solely on distribution facilities. Even if the lines are not subject to FERC jurisdiction, the sale is subject to FERC jurisdiction.

The second question is hard, and I haven't thought about it, but it would seem obvious to me that you want more federal authority over that question, rather than to have things balkanized. The entities that we're dealing with with a cyber attack are nation states, and it's enough to try to take those on at a national level. To try to take those on at a state by state level is not a good way to go.

Speaker 1: Well, your question calls on two of the things that, at least right now (of course, prediction is always uncertain) it seems we will be seeing more of. One is things happening at the distribution level with distributed resources and new structures to organize them, and the second is security threats to the grid.

To talk about the second a little, cyber incursion at the distribution level cannot hurt the bulk electric system unless it's connected to it. And if it's connected to the bulk electric system, then it's probably in some NERC registry category. I mean, it's definitely not perfect, but between the bulk electric system definition which took four or five years to finish and the recent risk-based

registration, which is an attempt to differentiate those people who are taking from the bulk electric system that can cause damage to it and cover them in some way in the basic standards, I don't think we'll see the cyber standards get less prescriptive or less inclusive, because unless and until we find a basic way to meet that threat, every single indication is that cyber incursions are going to get to be a bigger deal on the communications networks, on the electric grid and other places. So probably we'll trend toward more authority as we understand the technology better.

Questioner: What about the first question?

Speaker 1: I think I agree with what Speaker 2 said, that there's definitely room for state regulators to run retail choice or retail dispatch schemes in a different way than they do now. We're seeing some significant experimentation in New York and California around that. At some point, they will touch the wholesale markets almost by definition, and there will be more things to work out as we understand those interactions better. If this trend of DSOs continues, there will be more times we need to figure it out.

Speaker 3: I also agree with everything Speaker 2 said, except for the word "plenary." And I do think the DSO issue is a very interesting one--whether FERC can come up with some sort of standard distribution tariff market design. I think it might scare some folks. But at the same time, it's going to be a policy choice, in my view, that the agency ultimately faces, and the policy choice might hinge on whether we get to a level where the agency can actually make findings that existing transactions are creating discrimination in interstate wholesale markets. I think once FERC has made those kinds of findings, that opens up a whole range of possibilities for it to step into that arena.

Question 8: I have two questions for the panel. The first one is really directed to one of Speaker 3's statements. I'm talking about the concurrent jurisdiction, and especially the *ONEOK vs. Learjet* decision. You talked about how that's in the gas market, and given that the electricity markets are arguably even more complicated than the gas markets, do you think that there could be a Supreme Court case in the future where they could apply that same reasoning for the electric markets? Do you think the DR case could be the case where they talk about it?

So that's the first part of that question, and then, secondly, if you say yes, do you also think that the third and fourth circuit cases are opportunities where they could go there as well?

And then my second question is completely different. It's about net energy metering. I think we all agree that FERC has jurisdiction over wholesale sales, and, really, net energy metering, where the rooftop solar owner sells its excess power back to the utility, is a wholesale sale. The utility is going to take that power and resell it to a consumer. That will be the retail sale. So it is a wholesale sale that is currently not being regulated by FERC. And I'd like to hear people's thoughts on that.

Moderator: Well, why don't we start with the first set of questions, which I guess involve both the DR case and the third and fourth circuit cases?

Speaker 3: The answers are yes and yes. Do you want me to say more?

I mean, with the EPSA case, it's the flip side. It's exclusive state jurisdiction, but I do think that the either/or thinking of exclusive jurisdiction, when you read the DC Circuit opinion, really did influence the way the

majority wrote that opinion, and it's that either/or thinking that seems to be driving that case, and you definitely see seeds of that possibility in the capacity cases as well, each of which rely pretty heavily on preemption arguments, although I think the Fourth Circuit opinion left open stronger possibilities for analyzing this under conflict preemption principles. My own preference in these contexts is that we ought to address these kinds of disputes under conflict principles on a case by case basis rather than proactively have a court step in and say, "We're going to draw a line in the sand." I think if a line is going to be drawn in the sand, it ought to be by FERC, not by the courts.

Speaker 2: I think that you can't tell what the Supreme Court is going to do with these cases. I think the Third and Fourth Circuit cases were correctly decided, but, again, we're going to find out what the Supreme Court does.

As to your second question, I agree with you. Those are wholesale sales, and they should be regulated the wholesale level.

Moderator: I just want to touch on that second question on energy metering, because I don't think it's as clear. I mean, obviously, the electricity is going into the wholesale market, but I think this goes to the question, again, of the overlapping jurisdictions and this question of whether or not the fact that it's local makes it different. And I think it's becoming more of an issue if you try to move away from net energy metering and go to more of a general solar issue, where I just believe the states are better situated to be able to regulate those activities and to understand the impact on repairs and obviously the impact on the network and understand the impact on the distribution system.

And so this, to me, would be an example of an issue where if it is really so clear cut that it belongs in the federal jurisdiction, then that might be a reason that the Federal Power Act needs an amendment, because there are certain types of technological developments that really may be better regulated at a state level. Of course, where you stand depends on where you sit, and that's where I'm sitting right now, but I'm influenced more so by just being engaged with the wishes and trying to deal with the challenges that we're seeing quite frequently now of people coming to commissions and raising concerns. We heard them yesterday in some of the discussions, too, about grid impacts, and these are issues that I think maybe are better able to be dealt with through an administrative process at the state level.

Speaker 1: I invite any of the smart people in the room to correct me on this. There are a lot of former and present FERC lawyers around. But I believe the law of the Commission is that if it's less than 50 or 60% that you sell back, then FERC lets it be regulated at the state level, and if it's above a certain percent, then it becomes more like a generator and FERC takes authority. Something to that effect.

Comment: It's netted over the billing period, so if there's no net delivery over what's current, there are two cases which have used the retail billing period to define when the wholesale sale occurs. As long as there's no net delivery over that billing period, then FERC has found that there's not a wholesale sale.

Questioner: But in those cases, FERC has relied on its station power decisions that have been overturned by the court of appeals. So it hasn't been tested. You're right. It hasn't been brought before FERC.

Questioner #2: Could I ask a follow-up? I interpreted this question about net metering to be about a situation where somebody has a rooftop solar and is doing it. What if it's virtual net metering? In some states, there's an ability for an aggregation of people who want to buy in to a central station's solar project to get virtual net metering and how do you figure out whether that's going over transmission or distribution or whatever?

Moderator: That gets even more complicated, and this goes a little bit to maybe where FERC had come out on if you're netting most of it and it's only a little bit that's going to the grid, then it's more local. If all of a sudden it's a larger aggregated amount and it's really being sold into and impacting or effecting the capacity market, for instance (I mean, in some instances they might be selling that or bidding that in). And the situation you describe to me seems like it's shifting that pendulum in that direction, but that shows me less of a bright line and more of a situation where we can try to look at the facts and figure out, really, what is this that we're looking at? Is it really mostly affecting the local community, the local state? And if it is, which regulator is really better situated to deal with that? And I guess on the other side, is it going to affect in a negative way the wholesale markets? So if it's something that is really going to have an impact on the wholesale market, then I think that can lead in that direction.

Speaker 1: FERC has not been flooded with these cases, because right now I think a lot of the policy debate is at the state level around the stranded costs to the distribution companies and how you restructure their rates, whether they have customer changes, how much we want our distribution to be volumetric versus looking like a cell phone bill...and I think that debate belongs at the state level. I do believe it's coming back to FERC-- not how much you give

to the distribution company, but some elements of net metering will be headed back to FERC. I do think that that middle of the diagram is more of a mosaic than a blended pink color, and FERC will have to look and see whether things are fundamentally wholesale. But a lot of the debate right now is over the more retail side of it, which is, what are we doing to the utility business model? And I think that belongs at the state level and the debate is certainly happening there.

I have question. Has the volume of distributed energy resources that are net metered and therefore the volume of these types of wholesale sales increased to the point that you are finding, or independent generators are finding, that it's affecting the wholesale markets? I mean, is it more than *de minimus*?

Questioner: Yes. And we're becoming increasingly concerned. I, too, used to think that net energy metering was not an issue I had to worry about. It was a shame for the utilities. They have a lot to deal with. But it wasn't our problem. But we have recently, in, I don't know, the last six, nine months, just become increasingly concerned about the subsidies, and it is a really significant subsidy that they are getting for these sales, and because there's so much money, you're attracting more and more business from these solar developers who are doing all these very creative deals with residential and now garden solar or whatever they call that community solar. So from a wholesale perspective we are getting increasingly concerned about it.

Question 9: My question is actually mostly for Speaker 3, but any other comments would be good. When Speaker 3 talked about cooperative federalism, one explicit reference in the Federal Power Act about related to this is a mechanism that's never ever been used, which is the Joint

Board. I can think of a number of areas--net metering actually may be one of those, but another area would be on the siting questions that a previous questioner was asking about--and it would be interesting to know why that mechanism has never been used, given that institutionally it seems that's what it's in the statute for, to deal with cooperative federalism.

Speaker 3: Yes, I think there are instances where the statute directly speaks to federal-state relations and there is also, of course, the interstate compact provision. There are many other provisions like it as well that give states the ability to opt out of potential preemptive FERC authority with transmission siting. I think the statute does speak to some cooperative federalism possibilities, many of them being just consultative in nature, and it outlines some obligations, but I guess what I'm suggesting is that the fact that it speaks to some of those things doesn't limit those possibilities and that there are many other possibilities that we have at our disposal which FERC historically has used. Even if you look at Order 1000, you see examples of FERC putting in place regulatory mechanisms that work with state regulators in terms of establishing basic standards for organized markets. So I think the statute does speak to some of these things. I don't have any particular opinions as to why they haven't been used, but I think that it doesn't limit the possibilities, and that the possibilities are wide open in this context.

Comment: Wait a second. One of the reasons I think the Joint Board is not used is that it's not clear that FERC can actually be on the Board. The way that the Joint Board provision is written, and the way that it's been interpreted is that it's a Joint Board of state regulators, without FERC being a member. It's not meant to be a joint federal and state body. It was meant to be where FERC was one that was delegating.

Speaker 1: To my memory, there was only one time that I'm aware of where a state asked for a Joint Board, and that was an application from the state of South Carolina to do a Joint Board on mercury and air toxic standard implementation and at least how I looked at it, that was not an issue that was exclusively South Carolina issue, and instead FERC chose to reach out to NARUC, which is not a legal body, but it does represent all the states, and set up a structure of taskforces over a couple year period where FERC invited in different states and so forth, and that turned out to be, I think, a vibrant way to have the discussion that South Carolina wanted to have, because it wasn't just a one state issue. And it I think contributed to the safety valve that EPA put in the mercury and air toxics rule that gave a role to both the state and federal regulators. So I think that was a successful effort. But that was very much informal. FERC wasn't in "session." I believe FERC noticed the meetings, but it wasn't a formal state order under the Federal Power Act.

Question 10: I am not a lawyer. So my question is really to be educated. Could you guys clarify the difference between the series of cases in Maryland and New Jersey in which the issue is whether the state is exercising authority that it doesn't have to effect wholesale rates in an RTO, and then there are other RTOs like MISO, where the states have Integrated Resource Planning, or some of them do, and they are making decisions about generating units that will affect the dispatch, at the end of the day, and markets. So is it a question of the market rules and the differences between those different markets? Is it a question of the intention of the state in exercising its authority? Or is it something else?

Speaker 2: Let me try that one first. In the Maryland and New Jersey cases, the holding is

really quite narrow, and the holding is that if the state is doing something that attempts to set a state price to replace a federally set price, that is preempting. As to whether you could extend that preemption to other situations, those two courts didn't address that, and indeed FERC was asked to state its views to the Third Circuit. FERC concurred in the decision that the Third Circuit ultimately issued and urged them not to go further than that and to leave the rest of that to be decided when cases were put before them. And state Integrated Resource Plan--in areas where you still have the vertically integrated model, they don't try to set a price that replaces a federal price.

Speaker 3: Instead they use an incentive or a subsidy, and the difficult question going forward is, what's going to be permissible and what's not, right?

Question 11: On the 80th anniversary of the Power Act, let's go back to something that I think is getting lost in the debate. The Power Act, when it was passed, was meant to fill a gap that had been created by the Commerce Clause. And so when the Congress filled that gap, it did not explicitly or implicitly preempt the historic police powers of the states over utility regulation. That was abundantly clear. It was a gap-filling statute, not an expansion meant to preempt state law. And so when you think about the original context of the statute, then fast forward 80 years and ask a very simple question that I'd like the panel to think about. If FERC were to pass a rule-making tomorrow saying that every gas-fired generator in the country had to achieve a 70% heat rate, and every state in America had to have 10% renewable, 10% solar, 10% demand side management—if that was in a FERC regulation, would anyone think that FERC had the authority to do that? I think the answer to that would be unequivocally no.

So how is it, then, in 111(d) that somewhere in that statute Congress has given the EPA the authority that has been explicitly denied to the FERC? 111(b) and (d) are explicitly state statutes. They are meant for the states to implement within certain general confines. They were supposed to be models of cooperative federalism. They were not meant to be prescriptions imposed on state action. And so in the context of what we're dealing with today, I think the greatest modern threat to both the Power Act and state regulation is this 111(b) and 111(d) authority that the EPA claims to be in that statute. And so I'd like to know, does anyone think that FERC could actually do directly what I suggest versus what EPA is doing?

Speaker 1: I'll start. I don't think FERC could stipulate a breakdown of resources other than through its "just and reasonable" rate authority, and I don't think EPA can either. I believe that if EPA were here, and I clearly do not speak for them, they would say that the prescriptions you used were building blocks used to set the targets, and the targets have the force of law but the building blocks were just examples.

The question is whether those targets, once finalized, (assuming the final regulation, when it comes out, has targets) are lawful, and I make very few predictions, but I predict that will go to court. [LAUGHTER] But the EPA could not say, "You use 10% this, 10% that." I don't think they think they could. Those are building blocks to set the targets that I think they think they can set.

Speaker 2: I agree with you that FERC is not going to try to do this, and it would not be upheld if it did try to do this, and I don't claim to be an expert on the Clean Air Act. But I think there's a difference in statutory structure. The Clean Air Act is an act that preemptively fills

the field and then delegates to the states. An analogy might be PURPA. I think you have something of the same situation with PURPA in the Federal Power Act. You have the New York case challenging PURPA, but the authority that the states exercise under PURPA, I think, is arguably delegated authority by Congress rather than an authority that began with the state.

Questioner: Yes. And I think that is the fundamental difference. EPA is in fact preempting something. The question is what is that something? And I think it is mind-boggling, at least to some of us, that somewhere in the general language in 111(d) over what is a best system of emissions, that that language can be that EPA can do indirectly through federal authority what nobody would think the FERC could do directly, and I think that is the nub of the issue, and I think it is the greatest threat to the Federal Power Act.

I think this whole question about New York, the Third Circuit case, the Fourth Circuit case, EPSA, whether ultimately the clean power will upheld in its current form ... I think a lot of it is an academic conversation, because the state's authority over a lot of this is going to be preemptive.

Question 12: Actually this is perfect timing because I did want to address some of the issues with EPA. I think this conversation about FERC authority and Section 111(d) authority is an interesting one, and I would argue that there's a gap, and I'd like to hear opinions as to whether there truly is a gap here. While EPA has the authority to regulate emissions, and we can argue about what the best system of emissions reductions is, let's take this to its most extreme case and have the states open up every Title 5 air permit and run time restrict or emissions restrict every fossil unit on the system.

But I think we have to be very careful about what could potentially happen here, and, Speaker 1, you're exactly right. We do have a mechanism in PJM called energy and environmentally limited opportunity cost where we could actually price out those run time restrictions, except there's one small problem. It's not mandatory. And many of our generation owners do not use it today. And in operations we sometimes get transmission outages. We have to run certain units and then we get calls and they say, "We've run out of hours." Now imagine that on the scale of the Clean Power Plan. So I think that there is a gap here, and actually I think FERC does have authority to step in to make this opportunity cost mechanism mandatory so we can price this out so we can manage the system with security constrained unit commitment and security constrained economic dispatch. So I'd like to hear opinions on that.

But with the state federal jurisdictional issue, what would be so bad about the EPSA case upholding the DC circuit decision? We would put demand on the demand side of the market, rather than having demand pay or get paid for something to which they have not even purchased a property right in some cases. The capacity market is an exception. But in the energy market, what would be so bad about putting demand back on the demand side of the market? After all, technology has actually caught up with Econ 101 theory. And then, finally, are the federal and state jurisdictions truly blurred because of operational issues? Reliability issues have been mentioned, but I think from a pure reliability standpoint, if we look at the instance that we had in September, I think, of 2013 where we had to shed firm load because we had transmission outages and it got hot in some areas, if we had had operational visibility behind the meter about certain generation units or demand response in those areas, we may have been able to avoid that. All

of that stuff is state jurisdictional but, effectively, the RTO is operating one system. So, as a practical matter, it's blurred. So does the Federal Power Act really need to be changed to reflect the way the system truly operates? There's a lot going on here.

So what would be wrong with putting demand on the demand side of the market?

Moderator: Well, I can answer that. We had a lot of debates on that, and I don't know that there's anything wrong with that, but it can certainly be complicated, right? It would be a big change.

Earlier there was a discussion about how, if there were to be a DSO, that that would fall under federal jurisdiction, right? That potentially a distribution level market would fall under the federal jurisdiction, and in my mind if we were really to have to put demand response on the demand side, it's going to be complicated and probably have to involve some type of DSO for it really to work. And so then if we end up having debates about whether states have jurisdiction over helping make that work, I just think at the end of the day it's going to be far more complicated than the system we have right now, and, by the way, nobody forced the states that participate in the demand response market to do so. This was certainly an example of cooperation where states such as Maryland actively want to take advantage of the FERC jurisdictional market, and I think it helps make the market work better, and we're hopeful that the court will see that, but certainly if it has to go on the demand side, it's going to be complicated.

Comment: Especially in New England, with our small states, if we try to operate under state authority to do DR, it would just be a mess, because the states have different views of what

DR should be, and we have different industries, for example, the paper industry in Maine. So we've always strongly supported various types of DR. So putting that puzzle together, it's quite clear to me you wouldn't get unified efficient markets, because you'd have a bunch of different markets, much like we have on the RPS side. So that's one substantial consideration. If you want vibrant markets, I doubt you'd get them if you're operating under state authority.

Speaker 3: So one of your questions goes to the issue of FERC's role in managing the resources on the grid to maintain grid reliability, and those kinds of issues. And even though FERC can't directly regulate generation facilities, it's pretty clear that FERC has a role in regulating the value that different resources bring to the grid, and there's nothing new about that role. I don't think that role would change with the adoption of the Clean Power Plan, and I think FERC would continue to have that authority where it needs it to maintain grid reliability. How far would it go if every coal plant in the country shut down? There'd be a transition. It would be very difficult here. That might force a clash of some sort. But, hypothetically, that wouldn't stop all 50 states from deciding to do the same thing, and then FERC would have to make the same decision, right? But those are hypotheticals that seem rather far fetched.

Question 13: I've been involved in rooftop solar and net metering for the past two years, but until I walked in this room this morning, it hadn't occurred to me that somebody like Enernoc would sign up these solar panels and bid them into the wholesale market. And this is very concerning, because this is really an extension of Order 745. And if we have the same compensation scheme for this wholesale generation as we have in 745, we're going to have double compensation on steroids. So I just

want to ask. is this what the FERC is contemplating?

Speaker 1: FERC hasn't really done anything on net metering recently.

Moderator: I think we're going to pass on any more 745 questions because we're down to 10 minutes. My apologies that I didn't get to you sooner.

Question 14: I actually would like to go back to the discussion yesterday on markets and hidden values and ask a little bit about the Commission's role in that. One suggested prescription was to first get the prices right and fix the market design failures--things like better scarcity pricing, which the Commission has been very involved in, and also carbon pricing, distribution pricing, DLMP. Secondly, designing market hybrids compatible with good pricing policy, and that includes things like cost allocation rules to minimize market distortions. And I was really struck, reading in *Megawatt Daily* when Andy Ott was appointed to be president of PJM, and he said one of his highest priorities was going to be to address some cost allocation issues that have really been very difficult for PJM to address.

And I'm curious, we have a stakeholder process in a lot of the regions that has been somewhat stuck, particularly around some of these difficult issues, and, of course, it gets tricky when it's about cost allocation. And I guess my question is, with respect to "just and reasonable," what is the role of the Commission in sort of putting its finger on the scale a little bit around these issues, whether it's the RTO price formation, where you just had an excellent set of technical conferences, or the cost allocation issues, where some markets have different roles that do a great job of minimizing market distortions, and other markets just have other rules that maybe do a

poor job, but even if the RTO staff would want to resolve them one way, it's just stuck, and to me there's potentially a difference between "just" and "reasonable." Does that necessarily mean minimizing the market distortions? I'm curious to hear, because these are real issues that we see going on in a lot of the RTOs.

Speaker 1: Of course, you know I'm going to say there's no role for the Commission to put the thumb on the scale. FERC would never do that. But putting aside that expression, I certainly share the goal of trying to get the prices right. I mean, isn't that the goal of every market? And the Federal Power Act that we're here honoring on its birthday sets out the tools that FERC can use to do that. So if you look at price formation, FERC has the ability to act on cases that are brought before it under Section 205. FERC has the ability to initiate cases under Section 206 to say, "Hey, market," or, "Hey, all markets, here's something we'd like you to look at fixing,

because we don't think it's just and reasonable," or FERC has the ability to do more inquiries that could then lead to Section 205 or 206. Those are the primary tools FERC uses to help change things.

I think we're seeing a phenomenon in the RTOs. The stakeholder processes have gotten so complicated and the issues so technical that we're seeing more and more of the RTOs using whatever authority they have to file a 205 or a 206 without full stakeholder votes because of the technicality of the issues, but as far as the Commission goes, FERC can deal with what comes to it or FERC can initiate it itself, or FERC can ask questions that will give it the ability to initiate it itself later. And so those are the tools that FERC has as FERC looks at price formation and the tools that FERC has in general.