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Rapporteur's Summary*

Session One.
Pricing Carbon Emissions: The Promise and Pitfalls of Regional Approaches

With the delay or demise of the Clean Power Plan, states and regions are stepping further into the development of policies intended to regulate or put a price on carbon emissions. The inherent nature of the climate problem means that emissions anywhere should have the same impact everywhere. With a national standard, a common price of carbon could blend seamlessly with bidbased economic dispatch in organized markets. With regional approaches, the different or even conflicting approaches could undermine both the intended climate policy and the operation of open and non-discriminatory markets. Power flows across the grid in ways that could confound carbon accounting. Issues of leakage and so-called resource shuffling arise that would not appear in a national program. Different approaches have been followed in the eastern RGGI and the Western Energy Imbalance Market. Proposed policies could confront challenges on the basis of undue discrimination. What does this mean for state regulators and for legislators as they look at the power sector and its carbon footprint? What measures might environmental groups be advocating? What do we know about the theory and the practice of regional power markets and varied carbon policies? How can organized markets best accommodate different carbon policies? How can we ensure that the climate solution is workable and working?

Moderator: Welcome to the panel discussion on "Pricing carbon emissions: the promise and pitfalls of regional approaches." I want to thank HEPG for the opportunity to moderate this panel. I have to give my caveat that anything I say is my own opinion, doesn't represent the opinion of my organization, in case I say anything substantive. [LAUGHTER]

So this is a very relevant conversation. We have an RTO actively pursuing a regional approach to carbon. And to the extent that our states are the laboratories of democracy, it's sometimes good to check in on the experiments and see how

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they're going. And so we have one of those experiments going on. It's arguably one of the simpler setups, because it's a single state, and, as a single state, maybe a little less complicated than the more advanced versions, which might have multiple states with multiple different regimes. So the topic is relevant because we got something going on.

I think it's also relevant because we have other single state RTOs looking at this issue, particularly the New York ISO that is kicking off a very active and deliberate stakeholder process to consider a single-state carbon regime. And as they are kicking that off, they are also discussing the technical difficulties, the challenges that they'll have to get over in pursuing that option. So this conversation will be helpful for those who are active in New York and those who are watching.

And then, finally, in the FERC technical conference in early May that looked at the interaction between wholesale markets and state policies, a number of folks advocated a path that would have state policy objectives achieved through the markets, and to the extent that those objectives go to carbon, the advocates said that we should allow the states to pursue kind of a regional approach to carbon, and that that can replace the out of market actions that those states are taking. So in that context, it's good to talk about what we think the practical implications of regional approach look like, both for wholesale markets, for potential cost shifts among states when we're talking about a multistate ISO, and also for the achievement of those state goals amongst all the other issues you'd want to understand.

So, ultimately, I think what we're looking to understand is, is a regional approach to carbon, where states are setting individual policies, a realistic path forward? And can it realistically replace those out of market state actions, to the extent that folks are saying that that's the path we should go down?

Speaker 1.

Good morning everybody. I'm going to walk through a little bit of what the California ISO has been dealing with for about the past couple of years with regards to GHG and how the ISO has recognized GHG costs when we have some states that have a program and some states that don't.

So, the obligatory slide, what is the CAISO? We're the ISO/RTO in California. We serve about 80% of the state. We're the only ISO in the Western Interconnect. We've had aggressive renewable portfolio standards, as well as a cap and trade program. And we have seen, over the past four years, that we've been continuously decreasing our GHG emissions to serve California load. And we have a very robust and sophisticated real-time market, and we made that available to other balancing authority areas in the West starting in 2014 with PacifiCorp, and, as you can see, it's been growing very rapidly since then. And, in essence, we allow these balancing authority areas to participate in our real-time market. They maintain their own balancing authority area of responsibility, but we're able to do an economic dispatch across the entire footprint.

When we developed, originally, the Energy Imbalance Market, we recognized that only the California ISO had a greenhouse gas program, and all of the potential other states didn't. So we needed to come up with a mechanism to recognize that fact, because we wouldn't want to have, for instance, load outside of the ISO being subjected to greenhouse gas costs when their own generation is serving their load. So, under the current EIM design, we recognized that only certain generation has an obligation under the California Air Resources Board program. So if a resource is located within the ISO, any time it generates, it has a compliance obligation, even if that results in a transfer out of the ISO. If there's generation outside the ISO, it only has the compliance obligation when it's attributed to serving ISO load.

So we had to come up with some mechanism such that we could identify when a given generator was the actual resource supporting the transfer into the ISO. When that generation is serving load outside the ISO, it doesn't have a compliance obligation, and it doesn't have any greenhouse gas costs that it needs to recover. The way that we did this is that we allowed for resources outside of California, those EIM participating resourcing, to submit a separate greenhouse gas bid in addition to their energy bid. For generation within California, they just submit a single energy bid, because they have a GHG cost, regardless of whether they're considering internal load or external load. So, in essence, we do give the ability for resources outside of the ISO to completely opt out of ever being potentially subjected to the California cap and trade program, and they can do that by simply bidding zero megawatts, and that's the default bid for any EIM participating resource.

So what does this result in? It actually allows us to create a fourth component of the LMP, such that we can recognize that when there's an EIM transfer into the ISO, that generates a GHG cost, and we're able to then reduce the prices outside of California by that. So you can see, in this example, the energy price is $35 in the ISO, since there's a transfer into the ISO. There's a $5 GHG cost that is collected through the ISO's energy price and is then used to compensate the generator outside of California for its carbon emissions. But that cost is then reduced from the actual energy price in PacifiCorp so that its LMP remains $30. So the generation that's serving PacifiCorp load, in this example doesn't incur GHG cost, and that's not reflected in PacifiCorp's price.

So everything was going swimmingly when it was just PacifiCorp. But when we added Nevada, people started to see how this actually worked, and that there were instances, for instance, when Nevada joined, where we would see our resource in Nevada being attributed as serving California load, but not having reported that there was ever a transfer from Nevada to California. And so that raised a lot of questions among people in terms of how this was actually working. And so what that showed was that there are instances where you attribute one low GHG resource to serve load in California, and then backfill it with an emitting resource, because you don't need to consider its carbon costs, since it's not attributed to serving California load.

CARB (the California Air Resources Board) has mechanisms where they allow either a generic (or unspecified) rate, when you can't identify the specific generator, or the ability, when you can identify the specific generator, that you can use that generator's emissions costs. And so, we were specifically identifying the generator that we were attributing load service to, but we could observe that there was this backfill effect. So they're currently, in their regulation, implementing a bridge. Basically, they're taking the unspecified rate, minus whatever we attribute, and then retiring those allowances.

The EIM also has the ability to reduce emissions outside of California when California, in essence, exports our excess renewables. But it's important to know that CARB doesn't recognize this and doesn't allow a netting across intervals, so you can't take credit for saying, "Yeah, I know there were some secondary dispatch that happened this interval, but I did something good the next interval." Because they're really focused on what the atmospheric effect of the actual dispatch is.

And so they were concerned that if the resource was going to generate anyways, and we said, “Oh, that’s what’s serving California,” then we didn’t capture what really changed as a result of serving California load. And so we needed to now see if we could come up with an approach to try to resolve this issue.

I’ll sort of walk through an example to show how this can actually happen. So, in the EIM, all balancing authority areas come into the start of the real-time market balanced, so their supply and demand has to equal. So, generators have base schedules, and you can basically say that that base schedule was always going to serve native load. It was never for the purposes of export. And so we need to see if there are instances where it’s appropriate to attribute the GHG to that base schedule, even though its schedule didn’t change as a result of California load.

So in the setup to this first example, we have three participating resources outside of California, G1, G2, and G3, and they’ve all said they’re willing to serve load in California. They’ve all got a GHG bid quantity, basically, up to the Pmax (maximum power output) of the resource. So we can attribute to all of them.

So the first thing we need to determine is, what is the most economical solution independent of the ISO? In this example, they did optimize their base schedules independent of the ISO. But you cannot make this assumption. We can’t even make the assumption that an individual EIM balancing authority area has an optimal base schedule, and we definitely can’t make the assumption that all balancing authority areas outside of California in the EIM have optimized base schedules. But here we did make that assumption, and we can see that the energy price is set at $30, based on G3 being the marginal resource. There’s no redispatch, because everything’s optimal.

So now, let’s solve for the dispatch using the current market formulation of the EIM. And what you see is, given that generation in California is $40, it is cheaper to import power from either G1 or G3. The question is, which one do you say came to California? And when determining which one comes to California, we look at the GHG cost, and we see that zero is cheaper than $6.00, so, from a least cost dispatch perspective, we would want to, attribute that to G1. So we basically attribute the 200-megawatt transfer coming into the ISO to G1, and then backfill it with the output from G3 that we’ve actually incremented up from its original base schedule to 200. We set the energy price at $30 and there’s a marginal GHG cost of zero. But many would argue we didn’t accurately reflect in the LMP that the actual incremental load drove an actual $6.00 GHG cost, not a zero dollar GHG cost.

We’ve worked through several different approaches as we try to have a more accurate attribution, and we have sort of struggled along the way. For about two years, we’ve been trying to solve this problem. The approach that we’re currently testing is to have a two-step process, where we optimize the scheduled outside of the EIM, so we create that optimal dispatch, and then only allow resources that have upward headroom to have a GHG bid quantity greater than zero. So we’re looking at this currently, and we’re planning to put out a report at the end of the year to see if this is sufficiently accurate, as well as if there’s other issues caused by it.

So let’s look at the results of that two-pass solution. As you can see, for G1, since it was already dispatched in the first pass at 200 megawatts, we’ve reduced its GHG bid to zero. Now that it’s not eligible to be attributed to, we can attribute dispatch to G3. You see that the GHG price is now set by G3, so we have an energy price of $36 in the ISO, and a $6.00 GHG cost that's paid to G3, and the LMP outside of the ISO is still $30, as it was in the original scenario.

So how does this actually cause a bidding incentive? Well, as we see, if you're a non-emitting resource, and you can capture the GHG premium and not have to surrender a compliance obligation, then you earn a higher profit. And so, the way you would try to capture that is by bidding your energy such that you don't clear the first pass. That is, by trying to estimate what the spread is going to be between the California price and the non-California price, and be right in the middle so that you're not clearing the first pass. This does assume that gas is marginal, that it's not some other non-emitting resource or hydro, for example. And it also assumes that the GHG cost is large enough that you can overcome the risk of having to figure out where you want to price between the two points, and then you can capture that additional profit that you had earned, since you can get the GHG payment but not have to surrender allowances.

So, in the real-time market, which is the energy imbalance market, we've had many argue that this is less of an issue, because you need to submit a single energy bid that's used to clear the four 15-minute intervals and the 12 five minute intervals, and because the GHG carbon cost is small now. But I think as we look longer term, if you get the GHG cost significantly large, this becomes not as hard to figure out, and we have also been trying to regionalize, which is trying to bring additional balancing authority areas into our balancing authority areas, which will put them into the day-ahead market. And in the day-ahead market, it's far easier to predict an hourly price than it is to predict the 16 individual prices.

And one thing that we've been struggling with through this entire process is, as we try to go for higher accuracy of attribution, we introduce more and more pricing issues. So we had looked at, could you just go incremental to the base schedules? That caused issues, because the base schedules were incremental to an optimized approach. And then we identified that there would be instances where you would clear resources inconsistent with the bids, leading to bid cost recovery payments.

And now we're even a little less accurate, since you still can have a dispatch change from the first pass that is less than what you could be attributed, you still have the leakage, but are we now, is the bidding behavior, do we have to balance that? And the question then becomes, we do need the counterfactual if we want to try to capture and calculate what this secondary dispatch for these missing emissions are, because we're not able to do it now without the counterfactual. But the question is, what do you actually do with that information?

So we are having continuing discussions with ARB and our stakeholders, and there's sort of two thoughts. You could use the pure counterfactual to retire additional allowances, but this just decreases the amount of supply of compliance obligations and doesn't result in any revenue collection. And I would note that this is basically the bridge solution, except the bridge solution that CARB is currently using, where they use the default emissions rate, is higher than what is probably the actual leakage occurring. Or you can use the counterfactual to calculate some residual emissions, such that you can then try to come up with a hurdle rate or a minimum GHG bid price for non-emitting resources to see if you can address it that way through the market. And that is my presentation.

Question: Where do you come up with the value for the GHG? You were throwing out $5.00, $7.00… Is that some kind of a --

Speaker 1: Each individual resource has a resource-specific GHG cost, and we basically calculate a maximum bid price that they can submit that's cost based. So we basically take their emissions rate times allowance index plus 10%. That's their daily maximum bid price that they can submit. And then they submit that price, and then in the objective function we say that every time there's a transfer into the ISO, we have to cover the cost of whatever we're going to pay the carrier.

Question: And this allowance index, is it a public forum? Is it a traded index?

Speaker 1: Correct.

Speaker 2.
What I'm going to be going over basically springs off of Speaker 1's talk. I want to go into a bit more detail about what is causing the problems that we're seeing in the current EIM. And, as Speaker 1 mentioned, there could be pricing problems, possibly not capturing all the leakage. I want to go into some of the detail of what is driving those problems that we're seeing. So this may be a little more technical, but I'll try not to go into great detail.

I'll start off and basically say that EIM, as Speaker 1 said, integrated two GHG regions. You have California, with a GHG cap and trade regime, where GHG allowances must be procured for emissions caused by energy generated in California, and GHG allowances must be procured for emissions caused by energy produced outside of California that is deemed imported into California. I'll go into a little bit of how EIM currently determines what resources are deemed imported. EIM entities outside of California have no GHG regime, so there are no GHG allowances for energy procured and consumed outside of California.

Just very briefly, we're still using the security constrained economic dispatch models; however, it's augmented with some new variables. We have a variable which I have here as "P import," which is the energy deemed imported into California ISO from a generator entity, an EIM entity, with a GHG cost that's specified by the resource. That shows up in the objective function. And then we add constraints on the deemed imports. Basically, we're saying, let's look at the total amount of energy generated at an EIM entity, less the load. If that is positive, we're going to require that difference to be imported into California. It has to go to someplace. The only place it will go is California. If it's negative, nothing comes into California.

So that's the first constraint. Then we have a few others. You can't import energy unless you generate it. And as Speaker 1 said, people can say how much they're going to allow you to import from their resource. So a generator can say, "Nothing comes from me." Or, "You can bring it up through some maximum amount for me." So those are the constraints that were added into the SCUC (security constrained unit commitment) and SCED (security constrained economic dispatch). Fairly simple.

Now, what are the properties of this initial EIM design? Well, first of all, given the costs and constraints, it produces an efficient dispatch and import schedule. It's the least cost. We produce a locational, marginal price that reflects the marginal cost of serving withdrawal at a node. For nodes in CAISO, the GHG costs can influence the LMPs. GHG costs in CAISO influence LMP. GHG costs on deemed imports can also set the LMP if it's on the margin. GHG costs in EIM entities outside of California, they don't influence LMPs in the EIM entities. So if I'm generating outside of California, and it's marginal, the GHG cost on that resource does not influence the LMP outside. So that was one of the things we wanted to achieve, because the EIM entities did not want to see California GHG costs buried in their LMPs unless they were actually importing energy from California. (Then they've got to pay it.) The dispatch produces a marginal GHG cost for import into California which is used in settling the imports, and the important thing is the dispatch and import and prices are incentive compatible. If we look at the schedule a resource is given, that schedule will maximize that resource's profits when the resource is paid the LMP for the energy as it's dispatched and the marginal GHG-related costs for deemed import into California ISO. That resource is given a profit maximizing schedule. There's no reason for it to deviate, provided it bid its true cost.

I want to start setting up some examples to show what can go wrong whenever we try to capture leakage. And I also want to show some transmission constraints, because it's not just a very simple thing outside of California where it's just one node. There are transmission constraints that can interact with GHG charges, and it can make for some complexity.

So, there are some things that you have to look at when you're considering incorporating multiple GHG regimes. In this example, I have one generator in CAISO, and four generators outside of CAISO with different energy costs, different GHG costs, various loads, and transmission constraints. I'm only looking at two transmission constraints. In this case, I run today's market, and I get my dispatch. I get my LMPs. For example, the LMP at node one is set by P1, because you can see that generator is marginal. $48 shows up as the LMP. Similarly, for node two, P2A is marginal. It's between its min and its max. P2B is at its max. P2B does not set the price. P2A sets the price. It's at $36. And for P3 and node three, the LMP is set by a combination of generators one and P2A. This comes out at $24. Now, the interesting thing is that the import price on the GHG for the imports is a dollar. That comes when you look at the marginal deemed import. It's P3. Whenever I'm importing energy, the most I can import, due to the transmission constraint is 40. I'll take all I can from P2B, because it has no GHG cost, and then I'll take it from P2 or P3. It has a dollar GHG cost. That sets the GHG shadow price at minus one, and that's what we end up paying the imports. Whenever you look at that dispatch and those prices, you will see that each generator's profit is maximized by its schedule. There's no reason to move. It's today's EIM solution, and it's good as far as it goes.

However, CARB looked at this, and they said, you know, if you look P2B and P3, where you're importing the energy, those are the cheapest generators outside of California. Wouldn't those be used to serve load outside of California first? And wouldn't we dispatch some other generators up to serve the import? They're saying, by putting the imports on those two clean resources, you're causing leakage. So CARB wanted to capture that leakage. They're saying, generator 2B and generator three should not be providing imports. Somebody else should be.

So, first of all, we have to figure out, how should we calculate leakage? This was discussed for quite a while. It was determined that we should run a counterfactual. There may be many counterfactuals we could run. This is the one that was picked. What you're doing is saying, we're going to cap the import into CAISO from the EIM entities at zero when we run the counterfactual. That is, we'll determine the resources in the EIM entities that will be used to serve load in the EIM entities, since nothing can come into CAISO, but exports from CAISO to the EIM entities would be allowed, so they could export.

What's leakage now? Whenever we look at this EIM solution, I can calculate the total emissions in the EIM entities at the EIM solution. I can subtract off the emissions in the EIM entities at the counterfactual, because those are emissions that were caused by serving EIM entity load, and there's no GHG requirement for it. So that's the total change in emissions between the counterfactual and the EIM solution. But then I also have to subtract off the emissions for the deemed imports at the EIM solution, because I did capture some of the emissions. So that's a simple definition of leakage. That's what was defined here. Emissions at the EIM solution, less emissions at the counterfactual, less the emissions that were captured by deemed imports at the EIM solution. So now we have a definition of leakage.

So in this case, it's easy to get no imports into CAISO. You just change the maximum on the deemed imports to zero. Nothing can come in. And if you look at this solution, the counterfactual, every generator in the EIM is dispatched the same, except for P1. In the counterfactual, P1 has a dispatch of 103. In the EIM solution, it has 143. So we can calculate our leakage. It's 143 minus 103 times the GHG cost at generator one. For the other generators, generator 2A, nothing changed. It's zero. Generator 2B, I have zero GHG cost. It has zero. For generator three, I've gotten rid of the deemed dispatch to California. So my leakage was worth \$580. I have total emissions change of \$600, however, I've already captured 20, so that was \$580. We've got to somehow capture the \$580 of leakage and bring it into the market. That's the goal. How do we let the markets see that leakage and adjust the dispatch and prices to take that into account?

As Speaker 1 said, we're looking at a two-stage optimization process. The first stage solves the counterfactual. The second stage allows imports into CAISO, but restricts the deemed import from a given generator based on its dispatch in the counterfactual. The current approach being investigated is, limit the deemed import into CAISO from a given generator to the amount of headroom available above its schedule at the first stage solution. So if in the first stage I have a dispatch to a certain level, and given its ramp rates and its P max, I have room above its schedule in the counterfactual. I will allow imports from it. If there is no headroom, I will not allow imports.

So it's a fairly simple concept. It sounds good on the surface. In this case, what does that mean? Well, if I look at the generator P1, its P max was 220. I'm not looking at ramp rates. Here I'm just having P max, so it has 220. What was its schedule in the counterfactual? It was 103. I have 117 megawatts of headroom on that. I will allow up to 117 megawatts of import. P2A, I have 150 megawatts of P max on it, minus its counterfactual schedule of 79, I have 71 megawatts of headroom. I'll allow 71 megawatts of import. P2B, it has a P max of 20. I allow, and the counterfactual a schedule of 20, there is no headroom. I will not allow an import. Similarly for P3, its P max was 263. Its schedule in the counterfactual was 263. Zero megawatts of headroom, so nothing will be allowed to be imported.

So we just change the limits and run the EIM with those changed limits. In this case, you can see it's the same EIM dispatch as originally, except my location of the import has moved. P1 is still at 143. P2A is at 79. P2B is at 20. P3's at 253. However, there is no import from P2B, no import from P3. The 40 megawatts of import moved to P2A. Now, that looks good.

However, we can calculate how much leakage still remains here. And you should expect some leakage to still remain, because P2A, its dispatch did not change from the counterfactual. Nothing appeared there. However, I'm allowed 40 megawatts of import. P1, it's schedule went up by

40 megawatts, however I'm not importing anything. So whenever I calculate the leakage, I didn't capture it all. At the revised solution, I still have a 40 megawatt increase at P1, which causes 600 megawatts, or $600 worth of emissions. For P2A, I have 40 megawatts deemed import, so I'm capturing 280 megawatts of allowances. Whenever I add all of that up, I still have 320 megawatts, or $320 worth of leakage. I need that many emissions allowances to capture the leakage, and that has not been incorporated in the market. So it captures some of it, but not all of it.

So some is better than nothing. This might be OK. But let's look at the next thing. The other problem is, as Speaker 1 was saying, this could give participants an incentive to modify their bids. When we look at the settlements of this, generator 2B would be paid $36 in LMP at its location for its 20 megawatts of energy production, or be paid $720 for energy. It has no import. You get paid zero for import. And, assuming it bid its true cost, its energy costs would be $620. So it earns a profit of $100. However, this does not optimize generator 2B's profits. Generator 2B could look at this, start tracking it, and may get to the point where they can start forecasting this, and make guesses of what's going to happen and try to improve their profits. In this case, the prices themselves tell 2B that they are obviously not getting their maximum profit. Its energy is worth $36. Deemed imports, remember, were $7/MEh. They're only getting $36 for their energy, nothing for imports. In essence, we're telling it, you know, your energy could be worth $43 if it was properly allocated between energy schedule and import. So if it looked at that, it might say, you know, how about if I bid $40 for energy? Maybe I can capture some more. Now, if it does that, the dispatch will change. Generator 2B will be dispatched with 220 megawatts, and have 20 megawatts of deemed import. It will be paid $720 for energy, $140 for GHG, and it will have a profit of $240. Its profit goes up. So in this case, the prices don't give profit, or proper incentives to the individual generators. That can be a problem. How big a problem, I can't say, because I don't have all the data. I don't know how this is going to evolve. All I can say is, this is something that should be investigated, should be looked at, and possibly other approaches considered. I can't say that this will be huge or will happen all the time. I'll just say, it's a possibility.

So two stage optimization may not be able to maintain the desired dispatch price properties. One of the reasons for this is that the two-stage approach runs the counterfactual case, determines how much headroom is available, and it adjusts what can be imported from each individual generator. Whenever the final results come out, the individual is not saying, "Oh, my import was limited. That is the cost I will face." No, it's saying, "If my counterfactual was different, I might be able to import more," and it may end up adjusting its bids.

And as Speaker 1 mentioned, a different two-stage optimization approach was also investigated. One where you're saying, we'll only import incremental energy dispatched. If you go up from your counterfactual, that can be imported. If you don't go up, nothing can be imported. That one was found to have some significant pricing issues, where, at a given node, I may end up dispatching up a $36 generator, and dispatching down a $31 generator. I want prices greater than $36 and less than $31 simultaneously at that node. It can't be done. And it may not just be a bid cost recovery (BCR) issue, the way BCR is currently defined, because if I set the price at $36, that $31 generator is not seeing bid cost recovery. It's not being paid enough to cover its generating costs, which is what BCR gives it. It's facing a lost opportunity cost, and that lost opportunity cost is not included in BCR. So the whole definition of BCR may have to change if you get on that path. It's a very complex issue, and I think something to be avoided.

That's one of the reasons CAISO's looking at the current two stage approach. However, maybe there are other approaches that could be considered. And here I want to say that I give that example in the appendix. I don't want to go into all that. If you want to look at it, there's the appendix. It gives you enough data that you can set the case up and play with it yourself.

Now, the two stage approaches adjust what you can do on an individual generator. You may want to consider a single stage optimization, where you adjust the cost of importing energy from the generator based on the counterfactual. In essence, you estimate the leakage that you're going to see, and adjust the bid cost so that you're, say, if I'm importing from you, not only do you have to cover your GHG costs, but you have to pick up your share of the leakage, and you can't bypass that. That's a cost you're going to see. If I do that, I can maintain a set of compatible relationships between dispatch and pricing. So that part's good. However, there are other considerations that have to be considered. Does it capture the leakage? Well, it may not capture all of it. It can be off. Does it do a good enough job? That should be investigated. Are there other policy considerations that have to be considered, that we have to look at? Would this run afoul of something else? It's something that has to be looked at. This is not a completely solved problem.

The conclusion is that determining the best approach to incorporate regions with different GHG regimes in a single energy market is very difficult. It may not be possible to model the GHG effects across the region exactly, while maintaining pricing incentives that lead to a stable and efficient energy market. It's difficult to integrate two regions with different GHG regimes. Integrating three or more would be very challenging, and it hasn't been studied in California yet. So California can give you a good idea of how to do two regions. It can also give you some guidance on what to look at in making your choices on tradeoffs, and there probably will be tradeoffs. But it doesn't mean it's impossible, just that you have to go into it with your eyes open. But as to going to three regions, California can give you no guidance as yet.

So, to conclude, I just want to really thank California ISO and the other stakeholders, because a lot of effort was put in to get to this stage, a lot of studies, a lot of discussion, and I think some good progress has been made. I don't think we're done yet. But I think we can get through an acceptable solution as we go forward. Thank you.

Speaker 3.
I was asked to put sort of a legal gloss on what we've been talking about in what has so far been more of an economics conversation. So I warn and apologize in advance that I'm going to further complicate the problem that we have before us.

It said in the panel description that we were turning to these regional approaches because of the likely demise of the Clean Power Plan, but one thing to keep in mind is that the Clean Power Plan was not going to set a uniform carbon policy nationwide, because it really kicked the implementation to states and in some cases groups of states wanting to work together. We were still going to have these sort of uneven carbon policies. Some states were going to be able to achieve the goal just by retiring coal plants, or continuing with already planned retirements, and so they might not have then had a carbon price that would have gone into a market. So I think that with or without something from EPA, this was an issue that we were going to face, short of a legislative solution.

So the problem here, it seems, at least as it's first been introduced, is a sort of intersection between power markets and different regulatory regimes. This is nothing new. We see this all the time. But traditionally, a lot of the regulatory regimes and state based policies have been confined to the state. So even other pollution policies…you know, mercury limit in a particular state would require mercury scrubbers or some sort of cost of compliance on the generators located in that state. That price could be included in the market, and it didn't sort of cause this seams issue.

The problem here is when we're dealing with a pollutant or an externality or a harm that is global and goes beyond the borders of the state, and the state wants to capture that global nature of the pollutant. So they are concerned about leakage. They are concerned about resource shuffling. They're thinking about what they consume, rather than what is physically produced within the borders of the state. That's where this starts to get more complicated, trying to figure out how to price across those seams.

Today, we're using the CAISO EIM as an example. So one of the issues here is that we're all solving for different markets. Right? So, CARB is looking at the carbon market as the most important market in the scenario, and is worried about the actual atmospheric impacts of its regulatory regime. Those who are interested in the power markets first and foremost are concerned about undermining that least cost dispatch model and undermining the market system. Those two have difficult fundamental principles. They have different goals. They can be integrated, but as we're seeing, it's going to take a lot of work.

I'm going to further complicate this by adding another market that we need to keep in mind, first and foremost, as we're designing solutions in this area. And that's the US common market. So, since the US Constitution (this was a big departure from the Articles of Confederation) the United States has been considered one common market. States are not allowed to compete against one another, set up barriers to interstate trade, set border tariffs or adjustments on products coming from sister states. We are one common market. There are several pieces of the US Constitution that promote this. The one I'm going to focus on today is the Commerce Clause, and then, from that, courts have inferred the "Dormant Commerce Clause." There are lots of other issues that we could get into in terms of legal principles that we need to keep in mind as we're solving for these market issues. But today, in the interest of time, I'll just focus on the Dormant Commerce Clause.

So, the Dormant Commerce Clause is not explicitly in the Constitution. The Constitution's Commerce Clause just says that Congress has authority to regulate interstate commerce, but for more than 150 years, the Supreme Court has read into that a constraint, that because Congress was explicitly empowered to regulate interstate commerce, states are not allowed to step in and do that. There have been, over time, sort of these three tests that have evolved. They are complicated. There's a lot going on in them. I'm going to give a very brief primer about it today, and then talk about how it might relate to both AB32 and the CAISO and EIM proposals.

So, first, does a state law discriminate against out-of-state economic interests? This discrimination is not the same as Federal Power Act discrimination. This is about whether there is something that the state law has done that burdens out-of-state entities in a way that benefits similarly situated in-state entities. So, it could be that certain actors out of the state are burdened, or somewhat shut out of a market, because of a rule, but that's not really the test. It's whether they then have counterparts, similarly situated, that they are in competition with in that state that's seeking to regulate, and whether they are now somehow put at a disadvantage.

Two, states cannot regulate commerce that takes place wholly outside of the state's borders. We've been seeing a lot of constitutional litigation lately about state energy policy, so we've got some more recent cases to pull from here, including the 9th Circuit decision in the challenge to California's low carbon fuel standard, making it clear that states can reach outside their borders to reach a party in a voluntary transaction. So if there is an out-of-state party who chooses to play in a market in a state, they then can become subject to the state's regulatory authority, and that is very relevant in the case that we're talking about today.

And then, finally, if a state rule can pass those first two thresholds, there is then this balancing exercise. So, for the first two prongs of this test, it's strict scrutiny. Once you've survived those, it's much more of a deferential to the state balancing test of, what is the state trying to achieve here? And is that wholly outweighed by this undue burden on interstate commerce? So, for discrimination against out-of-state economic interests, there is the classic example of the border tariff. As a result, states are very leery about border adjustments or other sorts of taxes or assessments that are made at the border, because it just looks too much like the very thing that the Constitution and then the Supreme Court have tried to guard against.

The Supreme Court has also struck down laws that set quotas or limits like, either you have to buy from in state, or you cannot buy from out-of-state. In very, very narrow circumstances, a state can justify a discriminatory law by saying that it serves a really critical local need, and there's no less discriminatory way to achieve the goal. Quarantines are the classic example.

When it comes to tax discrimination, it is a whole other can of worms when we start talking about carbon regimes and carbon fees. California has done its best to avoid making the carbon regime look like a tax. It is involved in litigation that is claiming it is a tax. One of the big issues there is that under California law, if it were treated as a tax, you would have needed a two-thirds supermajority of the legislature to pass AB32. And so they are doing what they can to make this not look like a tax. However, for purposes of thinking about assessments, whether it's requiring first deliverers of electricity into California to surrender allowances, or potentially coming up with some sort of border adjustment solution here, it's worth thinking about the particular test that has grown up around taxes. There is this four-part test. It frankly collapses into a discrimination test again. Are we treating the outside entities differently than the in-state entities? Are they being asked to pay a tax the in-state entities are not being asked to pay? Are they being asked to pay more than the in-state entities? And this "fairly apportioned" piece of this test has also just been rolled into the discriminatory analysis. So, that means looking at, you know, is this consistent? Are you charging the outside entity about the same as the inside entity? Are you charging the outside entity only for the portion of their business that actually touches or reaches your state? This gets really critically important when we start to think about these deemed imports, and how you determine what actually has arrived in California, understanding that for electrons, it is a fiction that you can actually trace any one back to a particular source. But trying to make that connection of, we are assessing some sort of payment on you that is fairly apportioned to the part of your business that's reaching California.

There's also the issue of double taxation. Is there a risk that, if another state has a carbon policy, that they would be assessing a fee on the very same electrons?

That second problem that the Dormant Commerce Clause tests for is extraterritorial regulation. This is the part where states can't reach out to regulate wholly out-of-state transactions. So California is not able to directly reach out and determine where load is shifting outside California, say, from Nevada Power to PacifiCorp. If it's not going to California if California's not consuming it, if you're not seeing a transfer into California, California cannot reach those transactions. The Supreme Court has rarely struck down a law based on extraterritoriality. They have not at all in the last 50 years. That said, we are seeing this claim rejuvenated. We're seeing this a lot, particularly in energy cases. We are seeing that extraterritoriality argument being raised. It was raised against Colorado's renewable portfolio standard, saying that Colorado was now dictating to other generating resources in the region. The claim was that Colorado was saying, "We don't like coal anymore. We're going to discriminate against coal. We're going to tell you that we want you to be producing something else." It was also used successfully to challenge Minnesota's law limiting coal imports without offsets.

And, finally, if a state policy gets over those two hurdles again, we get to this undue burden, this balancing test, from a case about cantaloupes in Arizona. The ideas is that the state has its police powers. It has its right to protect the health and safety of its citizens. Does it have one of those benefits, one of those goals that it can point to, and then can it show that this is a fair balancing, that they're not placing an undue burden on interstate commerce to achieve that goal? It's very fact specific and really hard to predict. Often, when you get to this part, courts are willing to defer to a state.

Some key takeaways as we think about the CAISO situation: states cannot discriminate. So, again, it's about whether they are burdening out-of-state entities to the benefit of similarly situated in state entities. This is both for regulations or for taxes or payments or assessments of some kind. You can make locational distinctions for non-protectionist reasons. This came up in California's low carbon fuel standard. Out-of-state ethanol providers were saying, "It's unfair to include transport of ethanol in your greenhouse gas life cycle emissions, and it's unfair to consider the source of power that drives those ethanol refineries, because that automatically benefits California, shorter transportation if you're within California. California doesn't have coal fired ethanol refineries as the Midwest does." Because there was a reason, an environmental reason for those distinctions, notwithstanding the fact that it did benefit California, that was OK.

Additionally, states cannot regulate wholly out-of-state transactions. We've talked about that. And then, finally, state laws can't unduly burden commerce by subjecting activities to conflicting regulations. There are a number of train cases, train length cases and truck length cases, where states would say, "We don't want trains coming through our jurisdiction with more than 40 cars." And those would be struck down, on the theory that it's just impossible to stop at every border and sort of change up what you're doing. That potentially becomes an issue as we have more carbon regimes overlapping.

So, with California AB32, we get California wanting to do something about carbon emissions, wanting to mitigate them based on their consumption. California imports about a quarter of their electricity. California wanted to reach those imports in its regime. So it focuses on what it consumes and not what is produced in state, and that's where we get into some of these thorny issues with the regional markets. It's also where we get into issues with the Dormant Commerce Clause.

From the very beginning, AB32 and the implementing regulations were drafted with an eye to avoiding Dormant Commerce Clause challenges, but nonetheless, they raise Dormant Commerce Clause litigation risk, and so that's something that's important to see, in terms of why it was designed the way it was, and what constraints we have on solutions going forward. The statute said, minimize leakage. That's it. That's all it said on this issue. Those two words, "minimize leakage." CARB can figure it out. But by putting that in there, it suggested that they were going to look beyond California's borders to address carbon emissions from the power sector.

So the first potential issue is that when they're accounting for emissions from California, produced in California, versus imported, is there an inherent advantage for the in-state generators? With the in-state generators, you know where they are. You know what their emissions profile is. You can use a specified rate. California has been using, unless you can prove exactly where an import comes from, an unspecified rate for out-of-state generation which is equivalent to a natural gas combined cycle plant. You could have out-of-state cleaner generators saying, "This is unfair. We're being discriminated against. We would be treated as a specified resource and have a lower emission rate if we were in state. That's not fair, because we're out-of-state." You can get a specified rate from out-of-state, but there have been hurdles to that. California wanted to make sure that it was new generation or new capacity that was getting that specified rate, so they weren't just directing preexisting clean electricity to the California market. So, again, that was a potential Dormant Commerce Clause litigation risk. We didn't see any litigation in that area.

The regulatory targets that California has in AB32 and in the implementing regulations, are the first deliverers of electricity. The point there is to make it clear that it has a nexus to California, that they're not regulating wholly out-of-state activities, that they are finding some of those first deliverers are clearly in state producers, but some of those are out-of-state, and yet they are the last node before importing into California. They're deemed importers. The attempt there was to go beyond the border to deal with leakage, but not to go so far that you were starting to regulate wholly out-of-state transactions.

There's another point in the rules where it says there's no compliance obligation if you're a source in a linked state that has a sister carbon program. That's to get around that Dormant Commerce Clause issue of taxation of the same electrons, or overlapping and conflicting regulations. In 2012, FERC raised alarm bells about the resource shuffling ban in the CARB regulations. Resources shuffling was really vaguely defined. And it was unclear if it would have a chilling effect on out-of-state players wanting to play in the market. And so, California stood down on that. They did not enforce that ban on resource shuffling. They amended the definition in 2014 to make it a little clearer. It was less, before it was just based, it turns out that the price is not reflecting the power that actually was delivered to California, and that seemed too heavy of a burden, a very vague burden, to put on the out-of-state players. Now it was that they could not actively substitute electricity deliveries, still a vague definition. There's also a lot of safe harbor, so there's lots of reasons why first deliverers would be allowed to explicitly purchase lower carbon power supply for reasons other than lowering their compliance in the carbon regime; for instance, to achieve, to meet the RPS standards in California.

When EIM was first set up, it was in 2014, it absorbed this carbon regime. We've heard a little bit about this. But it figured out how to approximate the cost of the GHG allowance prices in order to have that bid adder. It also enabled out-of-state resources to opt out of California's market. This was important, because, again, there's that ban on regulating wholly out-of-state activities, and what saves California when it reaches out-of-state actors is that those out-of-state actors have voluntarily submitted to the market. If they are forced into the market and then subjected to a state's rules, that can cause problems. One really important thing, though, to note here is that California is not the same at CAISO. So the Dormant Commerce Clause constrains states from regulating interstate commerce. CAISO is not the same as a state. We know that from a case that we all cite for the direct effects test, CAISO v. FERC, which was when FERC tried to seat a new governing board on CAISO. In addition to that being the direct effects test case that has shown up again in recent Supreme Court cases, it also stands for the proposition that you can't say that CAISO is an ISO, but…asterisk, that it's not all that independent, and it's really basically a counterpart to California. It either is an ISO, or it is not an ISO. And unless FERC wants to say, "You are not longer an ISO," it needs to be treated like a regulated utility. It submits tariffs to FERC. FERC approves those tariffs. FERC is a federal entity, and so you are taken out of the Dormant Commerce Clause analysis entirely, which is another benefit to integrating the power market and carbon markets, because you then get out of this concern about the Dormant Commerce Clause.

That said, California meanwhile needs to do a lot in parallel with its regulatory program to match up to what CAISO is doing, and that's where you still could have Dormant Commerce Clause issues. This was the issue, just very quickly, with respect to the EIM. The enhancement proposal's been covered extensively by the last two speakers, but this was the issue that CARB started identifying. They looked at times when California was definitely importing power. This was the mix being dispatched in the EIM--mostly gas, a little bit of coal, some renewables. The deemed allocation of dispatch to California was, because of least cost dispatch, dominated by renewables and non-emitting resources. Now, CARB then said, the delta between those two charts was leakage. And CAISO (I think Speaker 1 mentioned this earlier) pointed out that not all of that difference would necessarily represent leakage. That delta is what California's using right now, or about to start using right now, with its bridge solution, to retire auctioned but unsold allowances to meet that delta. But trying to more accurately get an understanding of what real leakage is, is going to be the issue here. California updated its regulations in 2016. They went into effect this year, and that's what we were just talking about with the bridge solution. They thought about a number of other solutions, including making EIM purchasers subject to the regime, so making them part of that definition of first deliverers and making them directly responsible for surrendering allowances. They rejected this for a number of reasons. One, though, would be a potential Dormant Commerce Clause concern. They also then anticipated this two pass solution, which we've talked about a lot.

I just want to end on this point. As we're thinking about that two-pass solution, or thinking about other solutions for integrating these markets, that we do need to keep in mind the relative Dormant Commerce Clause risk of some of those solutions. So, we were talking a little bit about the method for determining what that actual leakage is. Say we use the two-pass proposed method, depending on how that is used by California, it could have different Dormant Commerce Clause effects. So, for instance, they could just change dispatch, and we've heard why that could be a problem for the power markets. That is the most straightforward solution for California, though, from a Dormant Commerce Clause perspective--that the market figures this out, and the market then shows that there are more carbon sources coming into the state, and California feels like it's getting closer to that leakage number. They could continue this bridge. They could just use the two-pass solution purely for attribution purposes, and then just figure out how many allowances to retire as a result. They could also do some sort of border adjustment, and sort of use that two-pass solution to determine what leakage is, or some other counterfactual to identify what leakage is, and then have those out-of-state imports sort of pay an assessment. That would be the toughest hurdle, or the toughest path forward in terms of the Dormant Commerce Clause. You'd have to get into whether you really were getting at what is leakage, and whether this is a fair apportionment of the burden out-of-state. Or is this just some sort of burden on the out-of-state similarly-situated entities that's not being placed on the in-state entities?

Just a couple other concerns, One is just who the target would be. We saw that they steered away from directly targeting the EIM importers, and would probably want to continue to do that. And, again, just from a Dormant Commerce Clause perspective, to the extent CAISO integrates the solution into the market, that does immunize California to some extent from Dormant Commerce Clause challenges. We did not even get into Federal Power Act preemption concerns, the other discrimination in the room, which is something else that is certainly worth considering--whether today's FERC, as constituted, would be concerned that some of the market inefficiencies that these solutions might create might lead us to unjust and unreasonable rates. And I'll end there.

Question: For those of us that don't follow California as much as maybe we should, has there been any litigation over AB32?

Speaker 3: There has not been a Dormant Commerce Clause challenge brought. There was a lot of speculation, both by California and by stakeholders and just observers around the country, that there would be. One of the reasons there may not have been is that there was sort of this parallel litigation happening on Dormant Commerce Clause grounds against California for its low carbon fuel standard, with some similar issues coming up. Were you treating disparately out-of-state and in state ethanol producers? Were you reaching too far into other states? So, very similar questions were raised at the trial court level right as AB32 was taking off. The low carbon fuel standard lost. California lost on the Dormant Commerce Clause grounds, but then the 9th Circuit reversed, I think, in 2013 or 2014. So that probably chilled litigation against at least the first iteration of AB32. As we start to move more into direct regulation or attempting to regulate resource shuffling, I think you could see it again. We have seen litigation more generally against California's carbon regime, and I think it's in state court. I think it is still pending, but it has to do with whether the carbon allowances are a tax.

Question: Two questions. First, you mentioned the extraterritoriality question, the Colorado litigation over the RPS. How was that resolved?

Speaker 3: That was actually resolved by now-Justice Gorsuch when he was on the 10th Circuit. The Colorado Renewable Portfolio Standard was upheld, and so that particular claim was rejected, because the focus of the regulation was on in-state LSEs, and it was up to them to buy the recs (renewable energy credits). And so the court said that so long as the target of the regulation was an in-state entity, you were fine.

The Minnesota case was a complicated one, and the three judges on the appeals court each wrote their own opinion. So what that one really stands for is kind of unclear. But it appeared that the vulnerability there on extraterritoriality was that Minnesota was regulating any person selling or importing coal-fired power into the state, and so the concern was, "any person" could include someone in North Dakota and someone in Wisconsin, and the power passes through the state, but it's a wholly out-of-state transaction. And that was something that the court was very concerned about.

Question: OK, thanks. The second question I had is, when you say that California is not the same as the California ISO, California ISO is a creature of California statute. Its board is appointed by the Governor, and it's run by the legislature. What's the distinction between California and the California ISO?

Speaker 3: That was exactly FERC's point when FERC tried to reorganize its board. And what the DC Circuit said at the time was, because FERC has recognized CAISO as a regulated utility under the Federal Power Act, that that makes it legally distinct from the state of California. In fact, in that case, it discussed that if you allowed FERC to interfere with that utility, one might also then extend that out to any privately held utility, because they are also a creature of statute, or at least are a creature of a state incorporation, and are reliant on state laws for their creation as well.

Question: Excellent presentation. If you want to put something in writing, I would love to receive it. It was a good summary of what this law is and the possibility of even further litigation. What's existing between California and Arizona is a lot of sharing of electrons, certainly with utilities in Arizona participating in California's market, but at times of the year, California is actually paying Arizona utilities to receive their excess renewables. So it seems to be a good relationship. But there's still discussion with certain entities in Arizona, my state, of getting into the Commerce Clause and perhaps even litigation. And the angle they're looking at, which is interesting, is that it affects Arizona's right to regulate their own utilities in the rate-making process, especially when the utility that's participating voluntarily (which it seems obviously the court has indicated is OK) wants to use those expenses in their rate making process to get a better result. And those entities in Arizona that are not participating feel that's discriminatory. Is that a possible avenue of litigation?

Speaker 3: Oh, interesting. I would definitely have to give that a little bit more thought before I gave you a full answer. On your first piece, we actually do have a general primer on this called *Minimizing Constitutional Risk*, and we're just putting out an updated version this week, so I'd be happy to send that to you. It's not specifically related to California, but it definitely lays out in the context of energy policy.

My quick thought about litigation is that it may get to the question of whether we're doubly regulating and whether there's sort of these conflicting regimes that are overlapping, like the same activity and the same piece of the players. But I definitely want to give that more thought.

Question: This is a minefield, but I want to ask about one thing that you said there, just to clarify. So, if I impose a non-tax tax on imports, and I'm discriminating against other states, I'm in trouble. That is what I took from that. But if the original situation, the premise, is, I impose a non-tax tax on my state, which disadvantages my state relative to the imports, and then I impose a non-tax tax on the imports in order to equilibrate the situation, is that treated differently, legally? Or is it just the same issue?

Speaker 3: Great point to raise. There's what is called the "compensatory tax" defense, so that if there is a tax that has been assessed on in-state actors, that the state can then assess an equivalent tax burden on interstate players that play in that market. Where it could get tricky here is just figuring out what "equivalent" is. What part of the activity of that out-of-state generator is actually arriving in California for purposes of being taxed? There needs be that fairer apportionment piece of it. But, yes, you can be compensating for a burden that is already placed on the in-state actors.

Speaker 4: In some ways, my talk is more basic than what you've just heard. Speaker 1 and Speaker 2 talked about how California already has cap and trade, and because it's part of the integrated EIM, it is having to deal with these border issues, and it gets fairly complicated. And then Speaker 3 talked about some of the legal challenges associated with that.

Now, in the East, we're not as far along in this discussion, really. So there's already the Regional Greenhouse Gas Initiative (RGGI), that's cap and trade, but prices have been de minimums. So that hasn't really been a big deal in any way, and nobody's really dealt with how that might be distorting the markets or how to undo that distortion.

But now, New York is at the early stage of considering whether to have more aggressive carbon pricing, in line with it's fairly aggressive decarbonization goals. And so they're specifically considering programs to procure renewables and keep nuclear plants online. What New York is now considering is whether to have a carbon pricing approach to complement that and try to get more of a market response. So I'm going to take a step back and discuss why New York would consider doing that and what impacts it might have on the market, on emissions, on customers. And at the end, I'll discuss interactions with the regional markets, relating back to some of Speaker 1 and Speaker 2's points, and possibly even shedding light on the types of transactions that we're talking about and whether maybe even this compensatory tax idea that Speaker 3 just mentioned might apply.

So, again, taking a step back, why are we talking about pricing of carbon? So, the wholesale markets, they price energy and reliability attributes, and they've been designed to meet reliability needs at least cost, and there are many examples of how the markets have enabled competition and innovation to do that. We've kept the lights on, and we've done it in ways that arguably reduce the cost quite a lot. But the wholesale markets do not meet objectives that are external to the markets, that the markets were not designed to meet. And so this has led policymakers to pursue targeted out-of-market approaches to supporting non-emitting generation. And the nature of the discussion at the FERC technical conference in May was that these policies and markets can interact in unintended ways and may not minimize costs and may even undermine some of the energy and reliability objectives of the wholesale markets.

So a very attractive alternative, then, is to price externalities. It's an old idea. It's the economist's favorite idea when there's an environmental externality, to price it into the market, and that would harmonize the state policies with the markets and should meet both energy and environmental objectives and do that cost effectively. Now, that's not to say, that this would necessarily fully replace the targeted out of market approaches. There are various reasons to still have energy efficiency programs, possibly ways to help suppliers of clean energy manage the regulatory risk around the clean energy value, and so various reasons you might still have some programs.

As we just discussed, California has already gone with a market based approach. They have actually put a quantity in the market, and let the market determine the price of carbon. Canada is at various stages of introducing carbon pricing with a possible federal backstop, and with the various provinces having their own approaches that are supposed to be consistent with that. RGGI, as I mentioned, is already there. Now, the price has been very low, but the new proposed program from 2020 onward would be more stringent. It would still have low prices.

So, again, New York is considering more aggressive pricing now. And that's what I'll talk about. And the thing is, often when we talk about whether to have a carbon tax or a carbon price of some kind, it's often a question of whether to even do anything about climate change or not. And that's not what's being asked here. So, New York already has aggressive goals to reduce carbon by 40% by 2030 and by 80% by 2050, relative to 1990 levels. And, related to that, there's a mandate now, in the electricity sector, through the Clean Energy Standard, to meet half of the electricity needs from renewables by 2030, and also, from now through 2029, to keep the upstate nuclear plants online.

Now, the question that New York ISO raised was, can decarbonization policies be pursued through the existing wholesale market structure? What are the market design options? There are various approaches: cap and trade, tax, carbon charges... And how would carbon pricing, if you did have it in New York, how would it affect emissions? Would it offer much improvement? What would be the economic efficiency gains? What would be (and this the biggest, political barrier, really) the impact on customer costs?

And by the way, again, carbon pricing isn't a new idea. What's exciting is that here's a state that has already established serious carbon reduction goals and is seriously considering carbon pricing as a mechanism to help pursue those. My firm was brought in to help figure how this could be done and what the impacts might be. And what we did is, we looked at a 2025 snapshot of the world, and we compared what happens if you put in a $40 per ton carbon price, on top of RGGI and on top of the existing program, and asked again, what happens to emissions, to total system cost, to customer costs? And we make a number of plausible assumptions on, what is the market response to that price? Which is a little bit hard to do. We don't have a crystal ball. But we've performed a lot of the sensitivity analysis on where we might be wrong about what the market response might be.

I'll talk at the end about what is one of the most interesting market design questions here, which is how to deal with the borders.

In general, this isn't complicated to implement. It's really a question of whether to do it. And the border is really the only, I think, complicated aspect. There are other complicated aspects, too, like if you were talking about a carbon charge, there would be a carbon fund collected by the ISO. How do you allocate that? There are some questions, but they're presumably resolvable. The only sort of tricky market design issue is the borders. But I'll talk to you about it in a way that shows there are simple ways to do it. I don't know about the legal aspect so much, but if you're not striving for perfection and optimizing over every unit in the system, there are ways to avoid the leakage, and it's basically the compensatory tax idea. So I'll get to that.

So, the first thing that we modeled is, if you put a price of carbon into the market, say you're charging $40 per ton. And the idea is that it's like an assessed cost on all the generators. So they have their fuel costs, their usual offers, but they also tell you their emissions rate, and so then you apply the $40 per ton cost to that. So just imagine, if the price setting unit in the market is emitting at a rate of half a ton a megawatt hour, the $40 per ton charge will increase wholesale prices by $20 a megawatt hour. So that's pretty basic.

One of the things we did is sort of work through how that affects customers, and I'll get to that in just a minute. But what does that price signal do to investment and operations? Because this is where the juice is. This is what's attractive. You use a market to find cost-effective solutions that weren't on the list of the targeted approaches with renewable procurement and nuclear.

This is where we had to, a bit, imagine what the world would look like with carbon pricing. How would it affect investment? How would it affect behavior? I think the assumptions that we made are very debatable, but plausible. We looked at how carbon pricing would affect renewable siting. I mean, they're paying a lot of money for RECs (renewable energy credits), but a REC is a REC. A clean megawatt hour is a clean megawatt hour, but, actually, it's interesting. Some of the renewables might be generating in times and places where they're displacing a lot of carbon, and some might not be. And if you put a price on carbon, you have this much better price signal for where to site renewables and what types. That, we saw, is a fairly big benefit. You might have the renewables siting in better locations—downstate, possibly, not just upstate. To the extent there's investment in new traditional capacity, you're going to push the economics towards the more efficient, lower-emitting resources, like combined cycles instead of peakers. There will be some incentive for energy efficiency, depending on how the carbon prices affect per kilowatt hour rates. We assumed some large customers would be responsive, and that there would possibly be some activity from storage.

What we found, based on the assumptions that we made, is that, with the state already procuring a lot of renewables and keeping the nuclear plants, introducing this carbon price would get you yet more emission reductions, because there would be a number of in-market effects on investment and operations that would save an additional almost three million tons of carbon a year that would reduce the emissions by an additional 9%, which is not trivial. And by the way, that's even before counting what would happen to changes in the dispatch.

New York will not have any coal, presumably, by 2020 or so, and so it's not like there's gas/coal switching, so there's not a really big dispatch switching opportunity in New York.

When I presented this a few weeks ago to stakeholders in New York, they said, "There's a lot of things that we would do. We're a fleet owner, and we have a number of efficiency improving things we can do to our fleet. And we would do them, if given the signal. And you didn't even count those." So I would guess that the benefits that we showed probably understate what the effect would be.

Now, if you're saving emissions by that much, you could either say, "Well, that's great. You get further towards these really challenging goals to decarbonize," or you might say, "Well, we're going to get to those goals. We would get to them with or without this pricing mechanism. Now we can get to the same level of emissions but do it cheaper, because we found in market ways to do it that were cost effective given the price. And now we don't have to do quite as many of the out-of-market things."

So imagine, for example, that you can buy fewer RECs. And if you did that, based on our estimate, this would reduce the total economic costs of meeting energy and environmental objectives by about $120 million a year. This is probably one of the most uncertain parts of our analysis, because it depends on everything I told you we imagined about what the market response would be in terms of investment.

Now let's look at the cost. Here's this little diagram of the net cost. It starts out on the left with the impact of the increase in wholesale energy prices, if the emissions rate of the price setting unit in the market is about half a ton a megawatt hour, putting that carbon charge on it of $40 will raise wholesale energy prices by about $20 a megawatt hour. And this number is sort of the really simple analysis that I think some people have done, "Oh, so that's going to cost customers an extra two cents a kilowatt hour." But that's really not the whole story. Here's why it doesn't cost as much to customers. First of all, as those generators are charged in the dispatch and in the settlement, that adds to a carbon fund. And the size of that carbon fund is sizeable. It would be, under these assumptions of about a $40 carbon charge, it would be about $1 ½ billion a year. If you returned that to customers, it would offset about half the effect of the wholesale energy price increase. Why is it about half? It's because there's a fair amount of clean energy in the market, and so the average emissions rate is about half of the marginal emissions rate. Anyway, that covers about half.

There are a number of other effects, too. So, if you still had the procurement of RECs and ZECs (RECs from renewables, ZECs from nuclear), the price of those procurements would be lower. If they're getting paid a higher price in the wholesale energy market, they don't need as much from the RECs or ZECs. So customers would save there, too. With the carbon priced into the LMPs, you'd actually have higher price differentials, say, between upstate and downstate. The transmission congestion contracts would be worth more. And the customers would presumably get that value. So, again, there are all these steps that take away a lot of what the price impact would be.

And then, finally, that's all static analysis before thinking through any changes in investment. Static analyses are always wrong. They always overstate what the effect is, because the market actually responds in a way that pushes back. So once you account for the fact that there'd be investment in emissions-reducing and, incidentally, price-reducing technologies, like adding a few more CCs (combined cycle plants), like bringing the storage more into action, like having some demand reduce itself during the peak periods, when you account for those, that again takes away, from a customer standpoint, a fair amount of the increase. And then, finally, customers would also benefit if they didn't have to pay for as many RECs, because, again, we found more in-market ways to achieve the carbon goals. And so when you take all those things away, the remaining cost to customers is pretty trivial.

What does that tell us? Almost by first principles, if you have a price-based approach, if you introduce that mechanism, it's going to save you money compared to not having a market-based approach. Right? It will find solutions that the targeted programs didn't. It will definitely save system costs.

What happens to customer costs? Do those go down, too? Or have we somehow created a wealth transfer from customers to clean energy generators? And the answer is, basically, no. If you look at the very right part of the diagram, the customer cost impact is essentially zero. Now, there are a lot of assumptions here. We varied those, and under all cases it was still around zero, and in some cases, even negative, (but trivially negative). That was one of the really key findings that I think makes it politically more palatable to do a carbon price.

Lastly, I'm going to talk about this topic we've spent most of this session on, which is the border charges. I don't actually love the term "leakage." It really understates what the problem is. Leakage refers to seeming to reduce internal emissions while just shifting production and emissions to external areas. But it's not just about emissions. It's also about economic waste. Think about it this way. If you put a tax on the internal generators, you're going to create distortions. That tax will just disadvantage the internal resources relative to external ones. It will increase imports. It will eliminate exports. And so, with leakage, what you can have is carbon pricing that distorts the dispatch away from what was just a simple least-cost solution, and so it increases costs, without even reducing emissions, and possibly even increasing emissions. That's a lot of what is troubling about leakage.

So, you know, you cannot put on a carbon pricing approach and not deal with the borders, unless there's just very little transmission capacity, very little trade. That's obviously not the case in California. New York doesn't have as much interconnection to other areas as California, by far. PJM has a lot. For PJM, one queston is, how are they going to deal with RGGI now having higher prices? If the more stringent goals are adopted, we're going to see prices kind of in the low teens probably over the next years. So this absolutely has to be dealt with, otherwise we're accomplishing possibly nothing environmentally, and we're just raising costs.

I am optimistic about being able to deal with the leakage, partly because I don't appreciate all the legal challenges. [LAUGHTER] But also because we started with a simpler problem of a single state RTO that is dealing with its border, as opposed to being mixed up right from the get go in an integrated dispatch out of a larger region. So we started with a simpler idea.

And here's the simplest idea. This simplest idea is the compensatory tax idea. That just that what we don't want is to disadvantage the internal resources relative to the external ones. Let's just take that away. So just imagine this. Imagine that there are no transmission constraints, and just that everywhere the price without a carbon charge would be $50. But with a carbon charge in New York, it would go to $70. This is before dealing with the borders. So now what happens? Anybody in PJM will say, "My God, look at that. I can get $70 over there. I'm going to send my power into New York and get an extra $20." And the idea is, just take that away. Right at the border. You don't get that extra $20. That's all it is. And that approach is actually really simple to implement. All you would do is, you would apply the same carbon charge, in this case, $40 a ton, and whereas internally you have the emissions rate of every generator, at the borders, all you would have to do is just say, "OK, assume they have the same emissions rate as the internal generator at the margin." And if you do that, it is simply taking away that $20 bonus that I just said would have distorted everything. So that's the simple approach.

Now, some people might think, "Oh, well, maybe we can do better than that. Let's really try to optimize," because what I just described makes the carbon charge invisible to neighbors. It's as if you didn't do it. (I'll return to this point).

One point I think is really important here is that, just as important as having a charge on imports, is having a credit on exports. Ontario has a charge on imports, but no credit to exports. California hasn't talked about a credit to exports. I don't think PJM has, either. And I think it is just as big a problem. In my example with the $50 price everywhere, except $70 in New York because of the carbon charge, think about New York to New England. Who's going to buy power from New York at $70 selling to a $50 market in New England? Nobody. Exports will just be eliminated. Right? And that might, by the way, seem to reduce emissions in New York. But all you've done is shift production. Now New England has to ramp up its generators, and they're probably going to ramp up generators that are emitting even more than what you would have done in New York in just a simple least-cost dispatch. Right? So, again, there's export leakage, just as much as import leakage. And the way to deal with that is to pay them. What you have to do is, if somebody would say, "Well, I'm not going to buy at $70 to sell into this $50 market," you have to say, "Oh, that's OK. I'll credit you $20. That turns our $70 back to $50." Again, that's invisible from the perspective of the buyer, New England. So that is just as important, and it hasn't been appreciated as much.

By the way, one reason I think California hasn't talked about it that much is that California has been, traditionally, an importer.

My central point is, this is do-able, assuming that this approach could survive legal challenges. It makes sense. The only thing that some people might not like about it (that I was starting to say before) is that it does not really distinguish. It treats all imports and exports as if everybody in the world is at the same emission rate as whoever is on the margin in New York, at the border point. Of course that's not true. It would be kind of nice to distinguish, if there's somebody cleaner available somewhere else. You might like to take that opportunity to bring them in and turn down somebody in New York. Or if New York has a lot of clean generation, it might be really nice to run that and turn down somebody in New England that's dirtier. And also you might want to say, "We'll take a little bit more from Ontario and a little less from PJM." And you're missing all those opportunities with a very simple approach that just makes the carbon charge invisible to everybody externally. So you could get fancier and try to say, "OK, we're going to have different border charges based on the emissions rates that we think are in the neighboring zones." There are tricky aspects of that, too. Again, that is doable. You could just come up with a set of blanket assumptions. It's a little like a wheeling charge. I mean, you could imagine it's fairly easy to implement. You could say, "OK, we'll just apply a charge to PJM, based on assuming they're at whatever point, say, six tons a megawatt hour, or whatever you come up with, whatever you think is reasonable. You could do that. So that's another possibility.

And then the fanciest possibility (it's really not an option for somebody like New York, but it gets naturally raised in the context of the energy imbalance market, or in PJM) is when you're part of an integrated dispatch. By the way, you could do the same thing as I just described, just creating basically a ring around your carbon regime, and charging for power coming in and crediting power going out. You can do that. If you want to get really fancy and get into a unit-by-unit optimization, then you get into all this tricky stuff with the two-step and the problems that have been raised this morning about the possible incompatibility between the dispatch and the price. It's sort of amenable to study whether that's a big deal, but it's definitely a big hazard when you go in that direction. So that gets into the much more complicated discussion we started with, but I'm not sure you even have to go there.

Finally, just in response to the moderator's questions at the beginning, a really fundamental question is whether a regional approach is a realistic path, and whether it can replace out-of-market actions. I think it is a realistic path. And it's also a reality. I mean, we have states with a very different view from the rest of the country, and some of those states have chosen to do carbon pricing, with a cap and trade system or possibly other approaches. And I think there are not particularly complicated ways that it could be integrated in a larger market.

Question: Your $1.5 billion a year pot for your $40 price on carbon--is that estimated nationwide, or was that a specific region? I didn't quite pick up on that.

Speaker 4: That's just in New York. It includes charging imports.

Question: I'd like to ask about the interplay between the various bars on your chart. If you were to take that pot, that $1.5 billion, and somehow write ratepayers checks and give it back to them, would you still have all the other benefits that you list, in terms of needing fewer RECs and ZECs? Or do you need to use some of that pot to pay the power producers?

Speaker 4: The answer is, no. That pot goes to consumers. The reason you don't have to pay as much for RECs or ZECs is because, quite apart from that pot, you raised energy prices, and so the nuclear plant is saying, "Oh, I'm earning a lot in the energy market." In fact, what we found is that at that price, the ZEC price would go to zero. They're earning so much in energy. Because, remember, the marginal units are raising the market price for energy, so the nuclear plants, for example, say, "Oh, it's great. My energy prices are $20 higher right now. I'm really in the money." And the ZEC price, going through the ZEC formula, would go to zero.

General Discussion.

Question 1: So my question is just sort of a broad question about some of these Dormant Commerce Clause issues when we are dealing with Dormant Commerce Clause challenges to state energy policies. And we've seen, actually, surprisingly few of them, if you think about how long renewable portfolio standards have been around, many of which were initially facially discriminatory, and some of which still are, in the sense that they have in-state multipliers or benefits for in-state facilities, versus out-of-state facilities. The Colorado case is really the only one. But you've got the potential for Dormant Commerce Clause challenges to state energy policies where the intent is environmental benefit or dealing with climate issues.

But then you have other state policies in the energy area that are subject to challenge that maybe don't have an environmental purpose, like state "right of first refusal" laws on transmission that are now starting to get challenged as well.

And as you see these cases moving through the courts, do you see, potentially, the courts sort of creating a new category of these state energy policies with environmental benefits, and sort of treating them the same and perhaps being a little more supportive of those policies than some of the other ones, like a state right of first refusal law, where it's hard to argue there's any state environmental benefit?

So that's sort of one piece of my question. Another one is, where do you see the Supreme Court going? You know, Justice Gorsuch is not a big fan of the Dormant Commerce Clause, and certainly the extraterritoriality doctrine. Justice Thomas is the same. Justice Scalia certainly didn't think we should use the Dormant Commerce Clause for much. And then you have the more liberal justices, who are maybe more receptive to some of the environmental benefits that the states are trying to promote. So where do you see that going?

Respondent 1: Great question. We could do a whole conference just on that. [LAUGHTER] I will try to be brief.

You're correct. There have been relatively few lawsuits relative to the number of clean energy policies. We've seen a lot filed, and then the state will sort of fix things. So, in addition to the Colorado, we saw challenges in Massachusetts and Missouri, and I think Delaware as well. And then you start seeing states just changing those explicit preferences and just sort of taking the sting out. We have seen a relative rise in the number of these cases, though, and I think it's because these markets are becoming more important. And we're seeing fewer of the cases being brought for ideological reasons, sort of by people who just don't like environmental regulation, and more from out-of-state clean energy providers who want to play in that space. They want to play in that market that was created by the regulations.

So while you still need to find a viable party who wants to bring a challenge, we could see more of that just as these become more important markets and there's money to be made in them. Courts have been playing on the margins of that, sort of looking to an understanding that there has always been from the very beginning of the Dormant Commerce Clause, this understanding that the point of this is to fight protectionism, and that if there are other real reasons that kind of fall in the state's police powers—for example, protecting the health and safety of their states, the courts are generally going to be more lenient on that. We've been seeing, in the recent energy cases, some language in those cases where they think about some of these non-protectionist reasons, although the cases haven't been decided on that basis.

And the reasons are not just environmental. You saw, in the New Jersey District Court case about the scheme to entice new natural gas development there, that the Dormant Commerce Clause challenge was rejected because the court took at face value that New Jersey was worried about congestion and said that relieving congestion is not a protectionist aim, and so you can take steps to address that. You've also seen some courts talking a little bit about how deliverability requirements might be OK if what you're trying to do is make sure that the RECs you're buying have clean air benefits to your state, since your state's paying for those benefits. We have not seen anything squarely decided on that, but there's sort of the beginnings of the question, could we build on this and make this sort of *per se* rationale for these types of cases?

The Supreme Court is really interesting. In the last five years, I think every single appeals circuit (or maybe all but one) has seen a Dormant Commerce Clause challenge to a state energy policy. None of those have been brought to the Supreme Court, and I think it's because there is great uncertainty about what would happen there, exactly the way you just described. You've got traditionally conservative justices who just don't believe in the Dormant Commerce Clause at all. Their thinking is that it's not explicitly written in the Constitution, and we've been coming up with these really fact-intensive, somewhat subjective tests over the years, and it's just time to get rid it. And then you've got a group of justices who might be willing to look at these non-protectionist, environmental reasons for regulation. But you also have this piling on of more state clean energy policies, and they sometimes run at cross purposes, and they're bleeding into each other at the margins. Whether it was the intent or not, one could paint a Balkanization picture that could be troubling to courts as well. So I think it's very unclear where the Supreme Court would go on these things. And I think, for the most part, this creates a specter of uncertainty for all the parties involved.

Question 2: I have a question about the EIM and the various approaches that have been considered and that could be considered for inclusion of carbon prices across the EIM. There was a little bit of discussion about the approach considered of just sort of applying carbon pricing broadly across the EIM, and I can imagine market participants that primarily serve load outside of California and don't currently face a carbon price (particularly with the slow pace of the Clean Power Plan working its way through the Court and the repeal proposal)…I can imagine a fair amount of skepticism about just applying that broadly across the entire EIM.

That said, as you all know, there's been a fair amount of political back and forth in California about authorizing a governance approach at the ISO that would allow a broader market that would encompass more than California and have more than just California representation on the board. Some of that skepticism is obviously driven by the concern about inclusion of out-of-state resources, both from a labor perspective and also from a carbon perspective. And I can imagine concern from those same sectors that might say something like, "You know, currently we're allowing this EIM. There is a lot of movement back and forth. There's opportunity for emissions to increase, even if those emissions increases aren't directly attributable to California load as a result of shifting." So imagine a political fight inside of California that says, "If we're going to operate the EIM, and certainly if we're going to participate in a broader West-wide ISO, we want the utilities that participate in that to opt in to the full carbon market."

Now, of course, that doesn't mean they have to pay California for those carbon emissions. They can give the funds back to their customers or allow their own PUCs to regulate how those are used. And I guess, as I said, I can imagine lots of political opposition from Utah and Wyoming and other sources. But I just wonder if any of you have already compared the current cost and benefits to the EIM, and potentially invite some speculation about the cost and benefits for customers of a more efficient dispatch under a West-wide ISO. I think, from everything I've seen, those benefits are significant and growing under the EIM, and only likely to be far more significant and growing even further under a West-wide ISO. How would those prices compare to current and forecasted California prices, and if those utilities were to participate, would it cost them more to participate, or less, if they were required to use the full carbon price?

And then, secondly, from a consumer perspective, assuming that those revenues from the carbon price were all sent back to customers, the way that they are in California under the California PUC rules, if that same rule were applied West-wide, would you essentially see effectively no net impact from a carbon price on customers, plus significant net benefits to customers from the more efficient dispatch of a West-wide ISO and/or, as an intermediate mechanism, the West-wide EIM?

Respondent 1: We haven't done an analysis that assumes that we put a carbon price on every single generator across the regional grid. I completely agree with you that Utah does not want carbon costs to be considered in their dispatch decisions. And we're trying to develop an approach to where we can meet each of the individual states' desires in terms of how they want to address carbon. And that's what we've been struggling with here. California has a program. They want to ensure that internal generation has a compliance obligation, as well as all the imports. And we want to also ensure that outside of California, those generators that are serving non-California load don't have a California obligation, but in the future they may have an obligation based upon their own states' policies.

So we haven't done the analysis. I think that if you say that, as part of regionalization, that you're going to price carbon everywhere in the West, that is a good way to stop regionalization moving forward. And I think a better approach is to let the states continue to come up with their own policies, and highlight to them that there are significant benefits when you coordinate those policies, which we've done through this initiative. We've been highlighting that we wanted to come up with an approach that's not just useable for the EIM, but scalable even to the day ahead market, because then we're talking about even larger amounts of energy being transacted.

But I also wouldn't want to lose sight of the fact that one of the ways that you integrate more and more and more renewables is having an advanced real-time market that can actually manage that uncertainty and the variability associated with them. And so I don't want to be putting in, for instance, accounting mechanisms that limit our ability to have the most sophisticated real-time market we possibly can. So I think we are trying to balance the individual states' policies, as well as recognizing that it is the real-time market that actually allows us to integrate more and more renewables, West-wide.

Questioner: Just to follow up, I don't disagree with that last point at all, and I absolutely recognize the political objections to inclusion of a carbon price across Arizona, Utah and Wyoming. My point was really just to ask about the cost/benefit analysis, and it sounds like that hasn't been done. But I think it might be an interesting question, given the political pushback on further market expansion from California that continues to be a barrier to that expansion.

Question 3: It feels like there is this kind of balancing of interests and objectives for California. You'd like least-cost dispatch. You'd like to achieve state policies. You would like to avoid legal risk. And obviously, you want to avoid leakage. So it feels like California is going down one road, based on a balancing all of those priorities. And part of my takeaway (and maybe that was a wrong takeaway) was that in balancing those things, and the way you're thinking about moving, maybe leakage is more important than lowest production costs. If you got a regional EIM, though, and a governance that was not just California-based, can you imagine a rebalancing of the priorities that you're managing as you implement this that puts less emphasis on leakage and puts more emphasis on other things?

Respondent 1: I still think that we would have the overall objective of having the most efficient actual market outcome, recognizing that leakage is sort of an external thing that we try to address, but we probably wouldn't do that at the expense of not having a well-operating market.

In my presentation, it said, look, we have this, now we have the counterfactual. We don't have the counterfactual right now, so for a lot of this, we can't even answer the question, in terms of how much leakage is actually occurring. But once you have that information, you can do something with it. The question then becomes, do you put it in the market? Or do you find some other mechanism to address it? But we still haven't gotten any results out of our parallel operations yet. Until we actually see some results, we really don't even know the magnitude of the problem we're trying to address.

Respondent 2: I don't think it's necessarily the California ISO board that's saying, "Address leakage." It's state regulators, state law that says that must be captured. So they're constrained to address it.

Question 4: Let me follow up on that. The question, to me, is, from a FERC perspective and a legal perspective, who really has authority over the ISO? Is it really a federal jurisdictional entity, at the end of the day, where FERC doesn't have authority over environmental rules? Or, as it seemed in listening to Speaker 1's presentation, and also Speaker 2's, is it CARB? Who's really in charge of the ISO here? I think we have really seriously conflicting legal jurisdictions here, and I don't think we've answered that question. What would be that answer?

My second question is, we've talked about the EIM, and we've talked about the current mechanism and proposed mechanisms. What happens if all the other areas in the EIM are balanced? California's still importing. You've still got the rest of WECC (Western Electricity Coordinating Council) out there. How do you deal with that problem with leakage? And the same is also true with New York being a part of RGGI. How do you deal with that leakage issue? And then, isn't a potential solution to the leakage issue just the fact that eventually transmission's going to bind, and we can't just import as much as we want from those non-carbon-priced areas?

Respondent 1: Unfortunately, we focused only on the EIM and the CAISO. We didn't discuss the other external stuff. Other external areas still can import into the CAISO. They can still bring it in in real time. The thing is, if they're offering in and can point to a specific resource, they can use a resource-specific emission rate. If they can't, then it's CARB's unspecified resource rate. So, really, we could have expanded all this to deal with it, but we thought it was sufficiently convoluted that we figured, we'll leave that out.

Respondent 2: And I'll add to that, because there's actually a third option. If you're actually a balancing authority area that has a lower emissions rate than the default rate, you can go to CARB and ask for an "asset-controlling supplier" rate. So, you'll see that the balancing authority areas that are predominantly hydro, they actually have a lower rate, even though they're not doing a resource-specific attribution.

Questioner: What if the flows are unscheduled, though? What if we're talking about loop flow? Which also gets to my issue in New York, too. What happens if there's loop flows coming through New York that aren't accounted for in schedules?

Respondent 2: To the extent that we would redispatch and increment a unit inside California, that would have a compliance obligation. And to the extent that we incremented somebody outside of California to resolve it, and it transferred into California, then it would have a compliance obligation. To the extent that we dispatched the other way around and reduced it, they just wouldn't output, and there wouldn't be any compliance obligation.

Questioner: I guess my question is, how do you determine who has the compliance obligation if it's unscheduled flows?

Respondent 2: I determine it by how I resolved the unscheduled flow--who I dispatched to resolve that. Given the fact that the unscheduled flow is occurring, and I have to dispatch around it, then there can be a compliance obligation. But you're correct. If there was just unscheduled flow into the ISO, and they didn't have to redispatch, there's no importer, no first deliverer of that energy.

Moderator: Is there an answer to the first part of this question, about jurisdiction?

Respondent 3: This is all really complicated, but my view of what's happening in California and with CAISO is that CAISO is attempting to integrate California's policies into the market. They're not bound to do that. They're not required to do that. Whether FERC has authority over environmental issues under the Federal Power Act is something people have been debating in the last few years, whether you can fit that into "just and reasonable."

But I think there is probably a stronger argument under Section 205 of the Federal Power Act. If they're reviewing a tariff from an ISO, and an ISO has said, "We've decided that the way to deal with this policy in this state is to integrate it in the market, price it, and then make it part of least cost dispatch," then I think you have FERC still driving within its lanes to approve that tariff.

It gets a lot trickier if FERC is sort of affirmatively deciding it's going to become an environmental regulator and sort of puts out, across all ISOs, "This is what we'd like you to do." That's still an open question.

In the particular case of California, we've had questions about the governance of CAISO. Maybe CAISO was more willing to work with California and try to integrate the policy because of its governance and the fact that it is so closely tied to California government. But I think, like any other ISO, it was attempting to just integrate this state policy into the market.

Respondent 2: We have a FERC-approved approach to GHG already. And the question that we got from CARB is, can we make it better relative to what their objectives are?

Respondent 1: We could have looked at leakage and everything and said, "Look, deal with it outside the market." And we could keep the existing system. However, if we can bring it into the market, we improve the price signals. So I think that's one of the goals—not to just deal with it outside the market and blunt the price signals, but to sharpen the price signals so people can respond to the cost better.

Respondent 4: And I'll just add, there is a case from a number of years back where the question did come to FERC, does FERC have jurisdiction over a green attribute cost? And there the answer from the Commission was, in the context of bilateral trades, when that was kind of a bundled green-plus-energy trade, to the extent that there's a green element of that, then that is jurisdictional to FERC. To the extent that those things are completely broken apart, or can be broken apart, so there's an energy part, and a green part, and they're unbundled, then the Commission doesn't have jurisdiction over the green element.

But I think you raise a fair question. If a filing came to FERC under Section 205, and the point of the filing was to address leakage outside of California, and there was a mechanism that California came up with that did that, but somehow you got higher production costs as a result of addressing that leakage, I can imagine that's a harder question for FERC to answer. Can it reject a tariff provision and a FERC jurisdictional tariff because something that's traditionally under FERC jurisdiction, which is least-cost dispatch, has been impaired by another goal, a state environmental policy? I think that ends up being a fairly hard question. But FERC probably still has jurisdiction to answer it under Section 205.

Question 5: This is a terrific panel. And I'm happy to say I agree with everything that was said. [LAUGHTER] But I do want to point out a few things that were sort of implied, which I think were not said exactly. And that's something that I want to address.

First, as a preamble, certainly in Speaker 1's presentation, and to some extent in Speaker 2's presentation, we used the word "deemed" or "attributed." So, "deemed imports" and "attributed imports." And that would go along in a sentence. And then someplace in the next sentence it would say, "but of course we want to make sure that we know the actual effect on what's actually happening with these imports." And any time you see those two things in the same mind at the same time, you're in trouble, because if we actually could color the electrons, if we actually identify the actual effect, and we actually knew that this one was really serving that one, we probably wouldn't be in this room, because we would have been done a long time ago. We would have the contract path theory. We wouldn't need RTOs. We wouldn't have economic dispatch. We wouldn't have locational pricing. All of these things would never have come to pass, because we can't actually identify where those electrons are going and who they're going to.

So any method that starts with that premise is in trouble. And so you just get ready for it as going to be in trouble. And I think we saw that here. A question was asked, is there a better two-stage method that solves the problem? I think there is a high-level answer, which is no. [LAUGHTER] And the high-level answer is, if the two-stage solution makes a difference, so that it affects what people actually get paid in the real-time dispatch, it is going to create an incentive for people to manipulate the first stage. So the only two-stage mechanisms where it will work are the ones that don't make any difference. OK? So I think that's a path we should just not go down. And it's unfortunate that California's going this way. And I hope they change their mind. It's unfortunate that PJM has pointed to it, and I hope they change their mind. I hope New York doesn't point to this and say that they're going to do this, because I think it's actually a dead end.

Now, the right direction to go is to get the prices right, which is always the answer for these kinds of problems, and the kinds of things that Speaker 2 was talking about I think are actually there, and a compensatory tax, combined with what California's already doing in the EIM is what I think is the right way to go, and the paper that's been distributed goes through that.

But I want to ask a question that has not been raised but was alluded to in Speaker 1's presentation. A lot of what is happening in the conversation with the CARB and its reform, I think you could read this as market manipulation in order to maximize the revenues collected by CARB. So, "We want the money to come back to us. We don't want it to go to somebody else. So, my goodness, we have renewable plants outside of California that, because of the compensation scheme, if they're deemed as imports, are going to get paid by California for the marginal cost of carbon, and then they have to buy permits for their individual cost of carbon, which might be zero, so they get to keep the that preferential difference. This is terrible. This is money from California customers which is going to renewables outside of the state of California. But we have a two-stage system where we exclude those people, and they can't actually sell into California. Now, the only people who can be deemed as imports to California are people who have a lot of carbon emissions. We pay them back at the marginal cost of carbon, but then they have to buy permits from California, and they have a lot of emissions, so they have to buy a lot of permits, so the money actually goes back to CARB." A related idea is, "We don't want to pay the existing plants. We only want to pay the new plants for this," which is another kind of price discrimination that goes on in this thing. I'm hoping that that's not what's actually motivating CARB.

What I've written in the paper is, I'm assuming that's not what's motivating CARB, that, "We want the money, and we don't want other people to get the money." Is that what's motivating CARB? [LAUGHTER]

Respondent 1: No. [LAUGHTER] And I would point out that there is one element of our design that we didn't talk about a lot in detail, but that recognizes that you would want California to go contract with renewable resources outside of California, potentially. And so we had this concept of California's supply, so that, if it was an external resource that a load serving entity in California had contracted with, consistent with CPUC rules or their local regulatory authority, that we would not treat that as an importer in that first pass. So we did recognize that. And I think CARB agreed with that, because they do want to incentivize renewable resources outside of California as well, and make sure that they get the right price signal. But I think there are camps that would highlight that if you do allow all of the attribution to be to a green resource, of course you're going to have fewer instruments having to be surrendered, and that's just the way it is.

Respondent 2: In conversations with CARB, it seemed like the concern was less about the revenue loss and more about the headroom of allowances that could then be used up by other sources in California.

Respondent 1: I think the fact that from their bridge standpoint, that they were willing to just retire allowances does show a willingness to not always, in all cases, try to get --

Questioner: In other markets, that's called monopoly. [LAUGHTER]

Question 6: So I have a two maybe related questions. The first question goes to the folks who looked at California. Have you done any analysis of the single-stage approach, whether it's Speaker 4's approach or something else, that simply says, "This is the price we're going to attribute to imports," and what impact does that have on dispatch?

And then my second question is, does it matter where the money goes? I'm thinking of things like the old milk subsidy cases. Is there a Dormant Commerce Clause issue raised, depending on who gets the revenue?

Respondent 1: On the first question, the key benefit of the energy imbalance market is doing resource-specific dispatch. And so putting on just a generic hurdle rate may not actually get us the lowest GHG systemwide. And so, if you look at what we did pre-EIM, there were those three examples. You could have a resource-specific outside source, if they have a contract with an IOU. You could have an asset-controlling supplier, and you could have the standard hurdle rate. And most people just accepted the standard hurdle rate, importers, and just said, "That's what it takes to play in California. I'm just going to go down that route. The other two, they're just too much work to actually get to where I could get that resource-specific, to get those lower emissions rates." I think in the EIM, we wanted to, again, have that resource-specific attribution so that we could have that resource-specific dispatch of those resources, whether they're serving California load or serving non-California.

Questioner: I think that's kind of the point, though, isn't it? You're influencing the dispatch of things that are not serving California load. And that's part of the function of attribution in this case.

Respondent 1: But the function of attribution is to ensure that we don't impact the price outside of California. We only reflect the cost of carbon when we have transfers into an ISO.

Respondent 2: I'm not sure I agree that to just have a hurdle rate that's uniform around California, that that somehow undermines the EIM's ability to do least-cost dispatch. I mean, first of all, you are already going away from a fuel-only least-cost dispatch when you introduced carbon pricing in California. Then the only question is, all of the approaches that you've talked about attempt to put California's view of carbon costs on external resources, to the extent that they might be used as imports. The uniform hurdle rate approach doesn't do that. It's allowing the external resources to operate according to their own view of cost, as opposed to California's. I agree that it misses some opportunities for reducing carbon emissions at the least cost. There may be opportunities out in the system for resources substituting for each other, substituting them for California resources, that, it's true, you'll miss with a uniform carbon charge. But, other than missing that, I think you're otherwise still doing a least cost dispatch.

Respondent 1: You're going to be missing a lower cost hydro resource with an opportunity cost relative to an internal gas unit. The least-cost solution is actually to take the hydro resource to serve California load, rather than having the internal gas resource serving the load. So the fact that I've applied this hurdle rate to that individual resource means I've actually increased emissions from what was economic to serve California.

Respondent 2: I disagree a little bit. You're putting a charge on the internal gas resource in your example, right?

Respondent 1: In their energy bid.

Respondent 2: Because they buy allowances.

Respondent 1: Plus their allowance cost.

Respondent 1: Right. So they've got that. And the idea of this sort of compensatory tax approach is, you know, if the hydro were to come in right now, they would get this extra bonus. I mean, there would be this extra incentive for anybody outside to come in, hydro or fossil, anybody. And the idea of the compensatory tax is, "Oh, just take away that extra bonus." This doesn't in any way say, "Don't bring in the hydro." In fact, if you simulate this, versus having no carbon allowance price inside, you basically get the same imports from external areas that you would get without having the carbon price inside California. That's what the uniform hurdle can do.

Just to be clear, the idea is, in California, you could describe a carbon component of the LMP. As long as you know what the allowance price is and what the emissions rate is of the marginal unit, you can talk about the carbon component of the LMP. All you're doing is saying that anybody coming in, "Oh, they don't get that."

Respondent 3: I think that's different from what California's doing.

Respondent 2: It is different, right.

Respondent 3: What California is doing with, say, a uniform hurdle rate or, say, the uniform bid floor, is saying, "If I'm going to deem your specific resources to be coming in, in order to bring your resource in, which has a very low carbon cost, I will have to redispatch something else outside, which has higher carbon costs. We want to reflect those higher carbon costs on your import." So it's not focused on the difference between external and internal. It's focused on the difference in the external dispatch.

So let's say the EIM entity only is clean resources. All of it's clean. If they're coming into California and displacing a dirty resource, they will get the carbon price, because they are saving those emissions. It sounds like you were saying it a little different.

Respondent 2: I was describing an alternative world.

Respondent 3: But I think that what California's doing is the correct way. We want to reward people who come in and displace dirty resources.

Respondent 4: Just to interject a little, with the Dormant Commerce Clause, if you are treating an out-of-state hydro resource, for all intents and purposes, as a gas plant, because you've added that hurdle, you've now discriminated against that hydro, versus an in-state non-emitting facility. So you haven't made it blind. You've actually made it where it's harder for them to enter the market and play. They have an advantage to play in a carbon-constrained world, and you've taken that from them.

Respondent 3: Except that, internally, I may see different LMPs on my hydro units, because maybe I could not dispatch that hydro unit all the way up because of transmission constraints. Then it's going to see a lot lower price. What we're talking about with this carbon floor would be, in order to bring that clean resource in, I have to dispatch some other resource outside, because it has to back fill. And in essence, it's sort of like the congestion thing. We're saying, "We will not pay you that higher LMP. We'll make you pay through the redispatch, which allows you to come in." It's sort of analogous to congestion. Not quite the same, but it's analogous. So I'm not sure that it's really discriminatory.

Respondent 1: I think that's where it also gets to understanding how much that residual amount is. Because if that residual amount is small, then you're at less risk. But if it ends up being the default emissions rate, then you're going to have a big problem.

Questioner: I don't want to belabor it too much. I'd just suggest that California maybe hire Brattle to do a bigger deep dive into this, because it seems like Speaker 4 has the right answer here. If you've got a hydro unit outside, it's presumably going to be dispatched into the EIM market anyway, if it's a cheap resource, and the question is, at the margin, what's happening? You're concerned that there is some resource coming up. What Speaker 4 is saying is, make the simplifying assumption that it's the internal resource which is reflected in the price that's driving that, and then you have a wedge. So, just like you have a transmission constraint on the board, or you have another constraint where you set the prices in California as $40, and the impact of carbon is $10, I'm only going to import from the external region if there's a $10 wedge in that price and let people get up there.

Respondent 3: I think it's quite different from that in many cases, because I often have transmission constraints coming in, and they're fully loaded. Really, the marginal unit in the exterior region is in the exterior region. It's not a case of, well, I'm bringing this in. I'm displacing a dirty resource. I will not pay you that. It's to bring in that hydro, in order to bring it in, I have to redispatch something outside, because something has to serve the load out there. And we're saying, we want to --

Questioner: Yes, but you're just sort of bean counting. You've got a certain amount of imports, you're saying. And you're saying, "Well, I want to designate the hydro, the environmental resource versus the other resource," and that seems to be not what you're trying to do, and I think Speaker 4's solution addresses that. I mean, as the previous questioner says, it's just electrons.

Respondent 3: It's still electrons, but, really, if I wriggle my load in California, nothing outside is changing. If my transmission limits are loaded --

Questioner: That's true, if you're transmission limits are loaded, nothing has happened. Then you should --

Respondent 3: And that often happens. That often happens. I still have to collect the carbon for the external resources that are deemed imported. And if I'm sitting around, and I'm cherry picking all the clean resources (which might be the correct answer. I'm not saying it isn't), really, CARB looked at some of these things and said, "Look, those clean resources are not the marginal resources out there. You have a lot of dirtier resources which are moving. Really, to bring that energy in, you had to dispatch a dirty resource outside."

Questioner: Right, most likely it is a dirty resource that's on the margin.

Respondent 3: And they're saying, that should help offset the carbon price for the import, not the clean resource.

Questioner: I would agree. I just think that Speaker 4's solution addresses that.

Respondent 3: Well, I'm seeing something different there. It's not the internal resource. It's not external versus internal. I could blow that hydro unit up, and some other hydro unit will come on to take its place, or something else. That's not what's driving this. It's the external marginal resource, in many cases. If my transmission lines aren't all loaded, then, yes, I agree, that's the answer. But I'm seeing a lot of cases where they're loaded, where we've loaded up and tried to bring in as much as we can.

Questioner: It does seem that like this problem of figuring out what's on the margin externally is a very difficult problem, and maybe the best answer, and I'm wondering whether you've looked at it, is to just make an arbitrary determination that says, "This is what we're going to do. We're going to do it on the uniform level," whether it's the marginal internal or some other unspecified level. It just seems like you've created a whole set of complications by trying to do the two-step that might be alleviated, maybe imperfectly, in a one-step solution.

Respondent 3: I personally think that one-step deserves more investigation. Right now, we're looking at two-step, and they're going down the parallel operations saying, fine, let's collect the data and see what it does. But I agree that using a one-step, where you're adjusting the price in a non-bypassable way, might have some benefits. I haven't examined all the policy implications. It may blow up because of other reasons. So I can't stand up here and say, that's the answer. I want to say, we ought to be looking at a lot of things.

Respondent 2: I just wanted to make exactly the same point. I just want to be clear that Brattle hasn't advocated for that solution. I was just pointing out that there is this approach that's simpler and cruder, for a place that has lots of imports. It does not get to the precision and optimization that you might want to consider. But, anyway, I just wanted to clarify that.

Respondent 4: My role here is just to make it more complicated. To the extent that we are just sort of somewhat arbitrarily picking, here's who's on the margin, or coming up with some sort of proxy for leakage, to the extent you then are imposing that on that resource that transferred into California, and to the extent that was a non-emitting resource that you're now having paid, that can cause Dormant Commerce Clause issues, because you are now putting a burden on that out-of-state wind, solar, hydro that the in-state wind, solar, hydro do not have. And so you have now priced those guys out of the market, or made it more difficult for them to enter the market or to profit at the rate that the in-state would.

Respondent 2: I don't know if this makes a difference, but you can easily treat new resources differently if they have a contract with --

Respondent 4: Which California does now.

Respondent 2: Right, you could continue to do that. But your issue that you pointed out would still exist for existing.

Respondent 4: Right, it's sort of the fudge factor we're talking about here that can be what creates a problem in this Dormant Commerce Clause world.

Questioner: And then my second question: does it matter where the money goes from a Dormant Commerce Clause perspective?

Respondent 4: It matters where the money comes from and where it goes, to an extent. So, in the milk case that you were talking about, there was a tax assessed on milk consumed in the state, but then the tax revenues were given to the in-state milk producers as a way to support local agriculture. And that was not allowed. So, the Supreme Court has not firmly said, but has hinted, that it's fine to subsidize your in-state players if you want to do that. You can spend your money as you please. But you can't do it tied to a taxing regime where you've taxed everyone, and then you've basically credited back the tax to the in-state competitors. So, anything that looks like you are taking from an out-of-state competitor and giving it to an in-state competitor, whether it's an actual revenue shift, which I don't think is happening here, or you're just pricing the out-of-state competitor at a higher rate than the in-state, you can run into trouble.

Respondent 2: So quick question about that. A lot of RGGI revenues are used to fund energy efficiency programs. Would those be considered competitors to generation outside RGGI?

Respondent 4: Probably not.

Question 7: In this carbon scheme, when you're dispatching the units down, are there uplift payments being made? What's the magnitude? How does that work, if they are?

Second, it's pretty complicated already in California, with the single-state RTO that has at least limited boundaries. Would you see both the technical and legal implications of maintaining least-cost dispatch, not violating state jurisdiction, as making it nearly prohibitive to try and do a similar scheme in ISO New England or PJM?

Respondent 1: I'll address the uplift issue first. There isn't an uplift issue, given that they're able to put those costs within their energy bids for internal resources. And under the current EIM approach, there isn't an uplift issue either, because they explicitly have a GHG cost bid portion and an energy bid portion in both, which are considered in the optimization.

Respondent 2: I think it's a really complicated question, actually, because, yes, you have a single-state ISO, but we've been talking about what a heavy importer California is, and where it pulls imports from, potentially, is a very wide geographic area, which complicates it in a way that maybe smaller geographic area or states that are net exporters or somewhat neutral in the balance of imports and exports might not have. So I feel like it's a little bit simplified to say, "Whatever's happening in the California space, assume it's going to be a lot more complicated everywhere else." But certainly the more states you pull into this, and the more different policies in play, the more borders, that is a complication in a whole host of complications.

Respondent 3: And I would say that the GHG regime in California and the EIM is just two cases, and that's hard enough to deal with. If you go to PJM and other states, you might have three or more different carbon regimes. That's one thing. The second complication is, California in this is only dealing in the EIM, which is real time. Whenever you go to the other RTOs, you have day-ahead and real-time, and we also have to then look at, if we're making approximations, does the approximation change between day-ahead and real-time? Is that going to give people an incentive to bid strategically and distort? So I think there's a whole other layer that comes into play in PJM and ISO New England and other states.

Question 8: I want to follow the money, too. I'm very optimistic, at least about the theory of integrating carbon pricing into the market. But my largest concern is opposite to Speaker 4's. I heard Speaker 4 as saying that the seams issue is really the critical one, and we can resolve the political issue of getting the money back to the end users. My biggest concern is what happens to that money, and how we can ensure that the pot of gold goes back to the consumers and not to generators, the state budget, or some other costly new program. In California, how do you ensure that that pot of gold goes to the right place? [LAUGHTER]

Respondent 1: The California rule is, there's two stages to the requirements. So the first requirement came first, which was the CARB rule, which basically allowed free allowances to the load serving entities, based on an expectation of their load and their emissions factor. So those allowances are freely allocated. The load serving entities then had to consign those allowances into the market at the regular auctions. But all the revenue was returned to the load serving entities, regardless of whether their emissions were in-state or out-of-state.

Then, they also said that the PUC could authorize return of those revenues to customers, but not in rates. Which is to say, they couldn't make a specific rate per kilowatt hour reduction. They could return it to customers in other ways. It couldn't be like a fuel cost. What they wanted to make sure was that the price impact of carbon was seen in the per kilowatt hour cost of energy. So, for example, PacifiCorp, which has something like 12 customers in California (I think it's actually 30,000 customers in California), has significantly higher rate implications from the cost of carbon affecting their kilowatt hour rate than does, say, PG&E, because they have a much cleaner fleet.

The PUC rule then came next. (And there's a couple of different classes of customers, and I'm not going to get them all exactly right.) But for residential and small commercial customers, those revenues are returned to customers in biannual bill credits. So you get a big bill credit a couple of times a year that maybe covers up to a month or two of your electric charges. But then, over the rest of the year, you still see the price of carbon in the per-kilowatt-hour cost, the idea being that you then make adjustments in your consumption patterns and overall usage reflecting that price implication, but then every now and then you get this big bump. We actually argued in that proceeding that it should be a separate check to customers, rather than a bill credit, because we thought the economic impact would be somewhat more pure, but they would still get the full revenue returned. So that's how California's done it. I think there may be reasons around the margin

that could be imperfect. But that’s the California
rule on it.

Session Two.
Sustainable Capacity Markets: Too Much to Hope For?

The thesis underlying capacity markets is that energy prices alone would be insufficient to attract the investment required to assure a reliable supply of capacity. While that theory, and/or the need for centralized capacity markets, is not universally accepted, it has been widely embraced. Recent policy discussions have seen additional arguments added to the rationale for capacity markets and their design. These go beyond simply attracting sufficient investment to assure supply, and include broader social and economic objectives, such as resource diversity, promotion of non-emitting resources, etc. Such considerations are very likely to affect not only the structure and economics of the capacity market, but also dispatch operations/protocols and the energy market itself. A number of critical questions are raised by these design questions: How can price signals continue to reflect value and products if there is dispatch interference due to fleet operations or subsidies? How can social contracts be integrated into the capacity market as a capacity resource without distortions? How can contracts be designed to ensure that the industry can compete on a level footing with some certainty related to market rules if legislation continues to shift? And how can consumers respond to shifting costs without undermining the house of cards? How will the fundamental transformation of distributed energy resources affect the foundations of capacity markets? What will prompt a rationalization of underlying reliability standards that give rise to the revenue disconnect?

Moderator: This panel is very timely for many of us, including Albertans, so the faster we get started, the faster we get into the pivotal question, which I would summarize as follows: is it going to work? That's how I would summarize it.

So, in terms of trying to internalize social policy and objectives related to other criteria other than economic dispatch, what happens to subsidies? What happens to low capacity factor assets? How do you fit them in? And what, overall, what is going to be the impact on reliability, markets, and investment? Small questions. And last but not least is the question, is there a final straw that's going to break the camel's back?

Speaker 1.

I am very happy to be here. I was assigned the task of basically summarizing the key issues and talking about the key benefits and critiques of capacity markets. And since I do live in Alberta and we are moving to a capacity auction, I want to have a pretty Alberta focus at the end to try and motivate a discussion of how Alberta's having very, very similar issues. But I also want to talk about some recent trends with the DOE NOPR and other state-specific issues in the US, which are very important to think about when we're talking about capacity auctions.

So, again, my goal is just kind of to outline the motivation for capacity markets and, again, to talk about some of the main critiques and benefits of capacity markets. So, Alberta had an energy-only market design; Texas has an energy-only market design. Again, the reliant principle of that is we rely solely on these energy markets to both compensate for variable costs and marginal costs of production, and also to drive investment incentives--to motivate these investment decisions via the energy only market signal. And, again, a key component of this energy-only market is scarcity pricing. But, as we know, politically, scarcity pricing is challenging in the sense that allowing prices to spike is very politically challenging. In energy-only markets, there's no guarantee on capacity adequacy, necessarily, but these scarcity pricing signals are the essential components.

Well, the main motivation for capacity auctions, historically, has been this missing money problem, where we implement price caps in wholesale markets because, again, price spikes are very politically challenging and there's concern over market power. Well, this leads to, in principle, underinvestment, due to this lack of compensation and mitigating these scarcity pricing signals. So this is kind of the historical motivation for capacity markets. It's this classic missing money problem with price caps, for example. Then we need scarcity pricing.

Lately, things have changed, and state-specific policies have changed the game a bit. So, recent concerns have been about subsidized renewables--these region-specific policies that undermine the economic signals of wholesale markets, or this is the argument. And this has also been a motivation for the need for capacity markets. So, these are kind of the classic arguments and stories, or stories, motivation, for the need for a capacity market.

So, again, there are not many energy only markets left. There's been an increasing movement from energy-only markets to capacity markets. Texas, Australia, Germany, Nord Pool, and Alberta all have or had energy-only markets with different flavors. They all have very different market designs. Alberta, as I'm sure you know, is moving to a capacity market design, which I will talk about. So, again, capacity market designs are very, very diverse so it's hard to boil them down into one bucket. But there's many capacity market designs all over the world that have been implemented or are being implemented.

The principle idea is that we're going to solve this missing money problem, we're going to provide supplementary payment for resource adequacy, by effectively dividing the pie into this capacity payment for resource adequacy, this capacity product, and an energy payment. So, I hear, for example, the Alberta government saying pretty often that it's kind of just simply dividing the pie between a capacity payment and an energy payment, and nothing else is different.

But it's complicated, so you've got to be careful with what you say. So, in theory, yes, you're dividing the pie into an energy payment and a capacity payment, but with capacity market designs, it's never that simple.

Capacity markets are very, very diverse. Capacity market designs vary dramatically in the details, and, in my opinion, the details are critical. The common designs involve an annual centralized auction for a capacity product, which is the potential to generate electricity, and basically, then, you have a subsequent energy market to compensate for the energy services you provide. These capacity payments are secured in advance, three to five years in advance is the typical design, but, again, the designs vary by jurisdiction pretty heavily. And the capacity payment for new resources can be secured for one year or even up to five or 15 years for certain technologies.

The participating resources are typically conventional resources. More controversial is how you treat the capacity value of alternative resources such as imports, demand response, energy efficiency, and variable generation. But, again, you have some level of need for reliability. This is the key argument of capacity auctions, where the demand curve tends to be defined by regulatory resource requirements. And these regulatory parameters are very, very controversial. Defining the capacity demand curve is one of the most challenging aspects of capacity market design.

So, how you define the demand for resource adequacy tends to be complicated. But, effectively, to boil it down, capacity markets are compensating for resource adequacy and they're separating this energy and capacity payment. But, again, I'm reluctant to boil it down to be that simple because it's a bit more complicated.

To present both sides, advocates for capacity markets argue that this alleviates the missing money problem. It alleviates the underinvestment that happens in energy-only markets due to the missing money problem. It promotes resource adequacy by giving revenue certainty to assets, given this growing penetration of renewables. It reduces the risk premium, which people tend to argue lowers the cost of capital for investment. It reduces wholesale price volatility, and it motivates DERs and energy efficiency assets. So, these are the classic arguments.

The alternative arguments are that capacity markets are prohibitively complex. A lot of people critique the capacity demand curve. Defining the nature of capacity demand is very challenging. Some people tend to believe that regulators are risk averse, so they procure excess capacity. So, this kind of creates missing money, in the sense that if you procure too much capacity, you're suppressing wholesale prices which creates missing money. How you define the capacity value of imports is really challenging. How you define the capacity value of renewable resources and demand response is incredibly challenging. Again, I'm just trying to outlay the key benefits and costs of capacity auctions so that we can kind of dig into the issues in more depth.

With that in mind, I will mention a few things, because this talk is about recent policy issues. So, recently, state-specific and region-specific policy issues have created some major controversies and issues in wholesale markets and capacity market designs. As many of you know, there was a FERC conference in May 2017, debating how you combine these capacity and wholesale markets with these state-specific policies, and how we get rid of these undermining price signals of the state-specific mandates. And, again, the DOE's recent NOPR is proposing cost recovery for certain baseload technologies. This, again, kind of provides a carve-out for certain technologies and not others, and there are concerns that this is going to really destroy the idea and the price signals that are essential in capacity and energy markets.

Just to highlight some proposed policies, one is an idea we heard about this morning--let's price the attributes that states value, these kind of environmental attributes. Let's impose carbon pricing. Let's price the carbon attributes and let's ensure that we're providing a market design that values some reliability attributes. And I'm not necessarily saying cost recovery. I'm saying the wholesale market values the ancillary services stable assets provide, for example. That's one proposal that's been talked about.

ISO New England has this two-part capacity auction where they effectively treat subsidized and unsubsidized resources differently. They do bid mitigation in the capacity auction. Subsidized resources that are not cleared in that capacity auction can effectively take the existing capacity obligations of assets that want to exit, and basically get a capacity obligation that way.

PJM does not impose bid mitigation. In the first stage, PJM just stacks the bids of the assets, subsidized or unsubsidized. Whoever clears the auction are the capacity resources that get the capacity obligation. And PJM has a second stage, where they remove the subsidized resources and the clearing price that would have been absent those subsidies is the clearing capacity auction price. So, it's this kind of two-stage auction, and, again, it's more complicated than that, but that's the flavor of the two proposals.

In addition, there's talk about, "All right, let's just get rid of these issues, and move towards some cost recovery mechanism," and that's kind of the key to debates that are going on right now.

So, those are the benefits and the big challenges that are facing capacity market design, in way too short of a time horizon. It's more complicated than that, definitely.

Before I finish, I want to talk about the Alberta context, because Alberta's transitioning to a capacity market design from, historically, an energy-only market design, where we have very lax policies on bid mitigation. The market's relatively concentrated, with 70% of capacity owned by the big five producers. The regulatory market is very unique, in the sense that firms have no or very few bid mitigation mechanisms, and the intuition is that firms are allowed to exercise market power to effectively recover their energy costs and their fixed costs. The entry decisions are going to basically discipline the market.

So, it's a classic energy-only market design story. The market is fossil fuel heavy, with 90% of generation from coal and gas, 50% from coal, 40% from gas in 2016. And there are some really unique attributes that we got to think about when we're designing the capacity market in Alberta. You have cogeneration, which is 31% of capacity. I may be wrong, but I have never seen a market with as much cogeneration as Alberta. We're relatively isolated and a standalone market. We have some interties, but not a lot. No day ahead market. And 18% of load is residential. The rest is industrial and commercial. So, it's a very unique and strange market design, in some sense.

There's been a substantial change in policy. We are one of the unique markets where we have a carbon pricing mechanism that already existed. It's just becoming more stringent. And we're also implementing a capacity mechanism. So, it's a unique combination, in a sense. We're facing a unique challenge in Alberta, in the sense that there's a mandate to phase out all coal generation by 2030, and it's expected most of it will be phased out before then, but, effectively, we're phasing out 38% of capacity and 50% of all generation by 2030 with the objective of 5,000 megawatts of renewable capacity. So, this is an incredibly complicated task.

Why did Alberta move to a capacity market? Well, in the Alberta market, you have nearly 40% of your capacity exiting, if not more, if you're counting some simple cycle gas as well. So, there are concerns that the existing energy-only market design would not attract sufficient investment in this very dynamic and complex environment. And there was also a lot of concern about wholesale price volatility in the energy-only market. So, these were kind of the key motivations for why Alberta moved from an energy-only market to a capacity market design.

This concern comes, I think, from a lot of conversations that policy makers and regulators had with firms who are considering investing in Alberta. They signaled that they would not invest in Alberta without a capacity market. That could have been strategic, or it could be true that they see too much uncertainty in an energy-only market, and they believe that they would not have sufficient incentive to invest.

There was a lot of concern, when all of these policy changes were coming into place, that the energy-only market's not going to promote sufficient investment. So, this is kind of the flavor of the conversation here in Alberta.

I wanted to end by highlighting some things that I think are really critical for Alberta. We have an amazingly tight timeline. It's 2017, and the capacity market is supposed to start in 2019. That is incredibly challenging, and capacity markets are very complex. So I think regulators have to balance the understanding that, yes, the timeline is tight, but also you can't just design the skeleton and say, "We'll figure it out later," because you have to have policy certainty for firms to be willing to invest. I think it's critical that we define the metrics of the future market design before we implement that first capacity auction. Currently, we allow unilateral market power. Well, if the story of an energy-only market is we allow market power to motivate investment, if you have a capacity market that's attempting to signal for investment, well, where's the argument, necessarily, for allowing short-run market power then? So the argument, in my opinion, kind of goes away for the allowance of market power. So we need to think carefully about bid mitigation, and I know this is a heated area here.

So, Alberta's unique. Our demand is 18% residential. The rest is industrial and commercial. We are very oil heavy, and as much as people would love to believe we're good at estimating oil prices in the future, I totally disagree. So, oil forecast prices are going to really dictate our estimation on our capacity needs going forward. And I think this is a very big challenge, going forward, because if you overestimate demand or underestimate demand, you can have some pretty serious issues.

When it comes to subsidized renewables, even though we don't deal with the state-specific, region-specific policies, like the US, in a sense, there are also concerns that government policies can have unintended consequences. I'm not going to say much about this, but if you over-subsidize renewables or other assets, are you kind of creating these issues that are really prevalent in the United States? I think Alberta doesn't have the exact issues that the United States has, but there still is definitely a relevant conversation.

Cogeneration is unique in Alberta, in the sense that it is a very large portion of our capacity. So, how you treat cogeneration in Alberta is going to be a very big challenge. For example, my understanding is that PJM, for example, treats cogeneration by estimating the peak demand of an industrial facility, and they pay the capacity price on that entire peak demand. Then they can submit the cogeneration as effectively a demand response resource. They don't take net load, net of onsite cogeneration. But do you want to estimate net load when you're estimating the capacity obligation of these large industrial consumers? I don't have the answer to that, but I think there's tradeoffs with both approaches. That's something we really need to think about here.

Potential interties with neighbors. There's a big study going on here in Alberta. We don't have a lot of intertie capacity. So, there's a lot of interest in investigating expanding interties. How you treat import capacity in Alberta, going forward, in the capacity auction I think is critical for this conversation about the value of imports in the province.

What else? I'll end with what I think is probably one of the, if not the most, important aspects, which is policy uncertainty in Alberta. I'm from the United States, I'm not from Canada. In moving here, I've learned how things can change very quickly with a change in government. So, I think Alberta is kind of a standalone, in terms of our policy decisions. If you're making investment decisions, you take into account this policy uncertainty. So, I think the province has to be very careful, going forward. We're implementing carbon pricing, we're implementing a capacity auction. Well, if the government changes, we've got to make sure we mitigate policy uncertainty concerns. In my opinion, that's kind of a big thing that is somewhat unique and I think it's something that really is going to be concerning. Because if I'm, for example, not a large firm, and I'm considering investing in Alberta, I may be more risk-averse to investing than a large dominant firm in the industry, who I'm not going to say would be bailed out if something bad happened, but would be more inclined to believe that if policy changes, they're going to not be stranded, I guess. So, policy uncertainty, I think, is important. And I will stop there because I just kind of summarized what I've said.

So that's kind of the historical motivation with some recent trends, the Alberta flavor, and I think Alberta has unique aspects that make it challenging to implement capacity auctions.

Moderator: Thank you. The clarifying comment that I would have is that the 5,000 megawatts of renewables is an additional 5,000 megawatts, not 5,000 to meet a target of 30% renewable by 2030.

Speaker 2.
Thanks for the opportunity to talk to this group. Here we are in Alberta. We have a pretty simple structure, and we're going to talk to you about capacity markets, because it's a big job we're undertaking.

Alberta was one of the first markets to deregulate. I think we modeled ourselves on the UK. It started out with an energy market, and Alberta has been very successful under this energy market for the last 15 years, and we kept looking outside saying, "What are all these people doing? What are all these complex structures that they have, and why do they have them?" And so, until now, we've had the luxury of having a very simple price signal and a very simple market design. And the government for the last 15 years has essentially really stayed out of the market and allowed the agencies and the participants to run that market.

So, why a capacity market? We're still talking about, "Gee, maybe we should go back to energy only, and do we really have to do this capacity market?" So, the big question that the Moderator posed to me is, "What's your view on whether Alberta needs a capacity market, and does that make any sense?"

I think it does make sense for Alberta to go down the road of a capacity market, and that is due to the significant policy changes that have occurred and are going to occur. And I'll explain that a little bit more as we go along.

So, just to kind of put it into context, the climate leadership plan for electricity had several goals: to make sure we had a reliable and resilient system, to improve environmental performance at reasonable cost to customers, and to promote economic development and job creation.

The specific initiatives related to electricity were, first, to increase the carbon tax. In Alberta, we were going to increase it to $30. However, since then, the federal government has announced that by 2022, they expect all provinces to be at $50 a ton, or some kind of equivalent. So, that was very significant.

Second, the end of coal was announced, so that by 2030, there would be nothing produced with the fuel of coal. And the third initiative is the addition, as the Moderator points out, of 5,000 megawatts of renewable energy to the grid, and that equates to having 30% of the energy from the grid produced by renewables by 2030.

So, the timing and the size of these policy changes, I think, is really the reason that we must have a capacity market, and that the energy-only structure will not be able to continue as it has. I think all market designs are impacted by policy changes that are made outside of that sector for other reasons, and the more of that that is unpredictable, the more difficult it is to get investment without creating some policy stability.

Now there's lots of ways to create that policy stability. A capacity market is seen as one way to create a little bit of policy stability for the needed investment. So, the need for the capacity market is tied to lack of investment, uncertainty, risk of exit of existing generators before you have replacements, and just changes in those incentives. That's all really related to incentives to invest.

It's really interesting to start with our energy-only market in Alberta, where were don't know anything about capacity markets, and watch Alberta learn, as a sector, about capacity. One of the interesting conversations we have is about how much should be in energy and how much should be in capacity. In the current market, we do allow economic withholding, which means that that energy price is really supposed to reflect the investments that we need for capacity and energy in the one single price. There is no contract that you get within the energy market structure, so when you invest in Alberta, and we've done it for 15 years, we invest in 30-year investments with no contracts. I think it is quite amazing that we've been able to do that.

When we move to energy and capacity, the capacity market is, from what I understand, supposed to signal new investment in capacity. Now, we're in a big debate here in Alberta about how much money should be in the energy market and how much should be in the capacity market. And I think that does come down to what you're trying to design. And people begin to talk about what the split should be. How much should they put in energy and how much in capacity? I'm interested in your views. The view I currently hold is that it's not an input to the market design, it's an output. You want to signal the capacity investment you need by figuring out how much you're going to get from energy and ancillary services and see what's left that needs to come out of the capacity market.

When you look at PJM and ISO New England, as we have, below, you can see those numbers move around a lot. So, there is no one number that you should target as a capacity market, but I will be very interested in the views of those that are more familiar with these types of markets.

Alberta is unique in many ways. One, we're a very small market. We are a 16,000 megawatt market with approximately an 11,000 megawatt peak. When you look at the size of most of the other markets that are going to capacity, they're larger than we are. That affects the liquidity of your forward curve, and therefore your ability to contract forward. If you make a poor policy choice, it affects how big the impact of that is. We have a high percentage of coal and cogen in Alberta, in comparison to other jurisdictions. So, we're starting with a very different resource mix and moving quickly to a new resource mix. We have a very high percentage of industrial load factor. It's around 70%. I don't know if it still is the highest load factor in North America. With that comes a very small retail sector, which are the voters in our province who bear the brunt of those costs. Not only are we going to bring in a capacity market, but we're going to bring in a carbon tax, and I don't know if there's another capacity market that has a carbon tax. So, that would also be something that's very unique.

We have a lot of hydro in Canada, so we look pretty good, as a country, in terms of our carbon footprint on the electricity side. However, Alberta is probably the most fossil fuel intensive of the provinces. So, the movement to 30% renewable energy by 2030 for Alberta is a very significant change over the next 14 years.

So, those things all make it a unique situation for bringing in a capacity market and trying to develop a sustainable market that allows Alberta to remain competitive and delivers high levels of reliability. To talk a bit more about each of those unique characteristics, we are very small. I've been told we're the size of Zone J in PJM. I've been told that nobody else has tried to put a capacity market in in only two years and really meant it, and we do really mean it here. The ISO is working very hard to put it in in two years. Because of where we're going and as quickly as we're going, I don't think it's just an exercise in, "Let's think about it and let's ponder it and go down the road a little ways and turn back." We do need to create stability in our market, which is why we need that to occur. Because our market is small, we must ensure that price formation in Alberta is not distorted or there will be very large unintended consequences. A drop in the ocean doesn't have much of a splash. A drop in a glass has a much bigger splash.

Today, coal produces 60% of Alberta's energy. In 2030, it will produce zero. So we'll have to retire and convert all of our coal facilities in the next 14 years. That's a significant amount of investment for a very small market to undertake. The capacity investment signal for existing generation and new needs to be strong. If you get unexpected retirements because of poor policy choices, or you don't have a strong enough signal for new investment, in either case, on a year to year basis, it could have significant impacts for Alberta.

We have a very high industrial load factor, and, as Speaker 1 said, within that, there's a very large percentage of cogen. When you talk about cogen to people outside of Alberta, at first they don't even understand what we mean when we say "cogen" here. So, in order to incent oil and gas in the province, cogen has been given special treatment in our electricity sector. They're called behind-the-fence generators, and the way they're treated, from a transmission policy perspective, is helpful. As we move forward and develop the capacity market, we have to think about how that treatment looks for the capacity market and ensure that we can create a sustainable capacity market and we don't allow that blending of load and generation that occurs now to undermine the capacity market and the needed signal for new investment.

We have a high carbon tax, as I pointed out, and a high carbon tax along with the renewable generation will erode the energy margins for coal or any type of thermal generation. The capacity market needs to send appropriate signals to ensure that conversion occurs and new generation is built. And the future renewable generation, this will all be done under contract. It will get a contract for differences. It has a guaranteed price, and will make up a fair percentage of the market by 2030. So, if you want to continue to have other types of generation to support and to be reliable all the time, you need to make sure that you have a structure to do that, and that really leads to how you allow those assets to bid into the capacity market and how they're treated.

So, we have a big transition ahead of us. There are a lot of existing resources that have built on the energy-only design. Moving to the capacity market, we need to ensure that we don't get too much premature retirement, and I don't know if that's them bidding, at minimum, their forward-going costs, or what that is, but there has to be a recognition of the investments that have been made under energy-only and we need to provide some sort of bridge as we move into the capacity market. Second, we're now in Canada. Canadian financing is way different than US financing. It's maybe how we've avoided some economic crises in the past, but it also has a significant impact when you're developing your demand curve and your net CONE (cost of new entry). When we go to investors in Canada and say, "We're going to build this power plant," there is no loan B options for us. We don't have the levels of liquidity that you have in the US. So, we don't have access to the same type of financing that there is in the US, and it's very important that we get this variable right if we do actually want to incent new investment.

When it comes to capacity price formation safeguards, as I suggested, there is a significant amount of renewables coming on our system, and it will all be brought in under a full scale contract. So that has to be recognized, in terms of how the capacity market signal is created, or it won't be strong enough to incent any other type of new investment except for the renewables under contract.

Last, there needs to be marginal cost-only bidding in the energy only market. And this is really about that split. We have to ensure that we don't put all the money into the energy market, in terms of how we design it, so that there isn't any left to signal capacity. So, it's about the purity of that price signal to signal what it's supposed to. So, the capacity market must signal the need for new investment.

To say a little bit more about cogen, I think the biggest thing I would say is that generation and load needs to be treated consistently in the capacity market, and cogen behind-the-fence often represents load and generation behind a fence. And so, when you start to determine how capacity should be paid for, you need to be careful. The risk is that the costs of capacity are borne by our very small retail customers, the 30%

that aren't industrial load, and, given the size of our market and the size of that market, we need to make sure that there's a reasonable cost allocation across the sectors.

I think Alberta does need a capacity market to signal new investment, but it needs to make sure that the capacity, the energy, and the ancillary services are all doing their jobs and signaling what they need to. So, capacity needs to signal new investment, and the energy and the ancillary services market need to ensure that the day to day, the hour to hour, and the operating decisions the ISO makes are efficient and they meet the goals of the CLP (Climate Leadership Plan). Ultimately, all three of these must work together and provide the right signals for us to meet the objectives of electricity in Alberta.

Question: One of the things we've seen in the US markets is just a massive expansion of combined cycle gas plants. Even with low prices, we see those plants being competitive, and maybe not even needing capacity markets, certainly being inframarginal in that capacity market environment, and I'm wondering…Obviously, you have a tricky transition going on.

But if you like your energy-only market, was there any consideration given to having an RFP process with short-term contracts, say, five to seven years, to get you through the transition of replacing the coal units? There seem to be an awful lot of rules that you need to put in place to get this capacity market right. But if you said, "Hey, you know what, we need X megawatts of gas generation," or whatever kind of generation, and just do it by contract, and then have everybody know that, OK, the contracts are going to go away at the end, and then you've got the transition…

Speaker 2: I don't think I would speak to all the concerns that the government had. I think that as you look at any of these market designs, it all comes down to how do you incent new investment, and how do you keep the current assets you want on. And in Alberta, saying that you're going to give all the new guys a five to seven-year contract and everything is going to work out, I think it goes against the principles of the market we designed--that it was fair and we all had the same and reasonable treatment. And that's something I think really is at the heart of how people have viewed the energy-only market. There was talk of negotiating with all parties in Alberta if you gave contracts to one group, but, as has been pointed out to me, there's 240 assets and 100 market participants. So that's a big job.

I think there are lots of solutions that could have worked for Alberta. This is the one we've chosen. This is the one the government has said that we would go down the road of, so we are supporting them in ensuring that this design is a workable design. But there were and are other alternatives.

Question: I don't follow Alberta government or politics as closely as I probably should. Speaker 1 mentioned a change in government as one of the risks. Is it possible that a future government here in the province would just say, "Oh, the climate leadership plan was nice, but we're going to undo it and never mind?"

Speaker 2: Gee, you're reading the minds of us all. I think one of the unique things about Alberta is that for 43 years we had the same government. So, for the whole period of deregulation, we had the same government. I think that's very unusual. Just take a look around—at the US, England, France. There's big shifts in who people are voting for. So, there's more volatility in who's being elected. I think if we got a change in government, you could see the plan slow down, but for us to go to no plan doesn't seem likely. I think the world is going the direction of cleaner grids, generally, and I don't see that stopping. So, it'd just be a matter of whether they slowed the direction down. But it is a risk. It's a risk that Alberta hasn't dealt with. It's probably why our energy-only market lasted as long as it did--we had policy stability. And with changing governments, I don't think you get that same level of policy stability, and you potentially get a lot more policy intervention in the electricity market, which is why my belief is the increased complication is required.

Question: Just to follow up, it seems that that may impact someone's willingness to come in and invest, if they think that their investments may be undone.

Question: Not being familiar with the sources of electric demand in Alberta, how much of it is tied to the oil industry? Oil in Canada is sort of on the margin. If we see a move towards electric vehicles and reduced oil consumption, I'm wondering, how does that affect your electric demand, going forward?

Speaker 2: It's significant. About a third of the load is oil sand related. And that's where most of the cogen facilities are associated. There's that relationship.

Question: You mentioned that the Canadian financial structure is different than the US. If you're familiar with the way that US capacity markets work, what's currently being proposed in Alberta is very similar to PJM. Any kind of resource variable requirement in how they set the demand curve, ostensibly would take in the financing aspects, whether they're unique or not. So I'm trying to understand what your concerns are, whether there's something inherent in that approach that identifies a proxy unit and the revenues and how they would be attributed and financed. That's part of the whole capacity structure, and I'm trying to understand what is unique about Canadian financing that you think might not be captured in that structure.

Speaker 2: It's making sure that the assumptions that are used when we develop our demand curve reflect Canadian financing assumptions, and we don't just get someone from the US saying they aren't any different and developing our demand curve based on US financial structures versus Canadian.

Speaker 3.
First, thanks to Ashley and Bill and Jo-Ann for inviting me.
As I tried to prepare what to present today from a trader's standpoint, it sort of became clear to me that I just needed to at least lay out in my own mind this broad construct that we all exist within. At the top of this very simplified diagram (that hasn't been designed to represent any market in specific detail, but just in very general terms), we have an environment of environmental standards, a political backdrop, and a regulatory backdrop that creates uncertainty, creates rules that we have to live by. At the bottom, we have a bunch of the things that are also impacting the market, the shale gas renaissance and revolution, the LNG revolution that is going to start coming and maybe pushing the other way, a little bit. There's the renewable penetration that we've seen in solar and in wind, impacting the markets. There's demand response and distributed generation and their impacts on the market. Potentially the biggest game change to come at some point in the next, 5, 10 or 15 years, will be batteries, and solving the one problem that creates all of the complexity in the market, which is storage.

Our energy-only market, in general terms, is designed to do a bunch of things. We want to try and get the lowest prices for consumers that we can get, or some people say the most efficient prices that we can get, and it just depends whether you're a regulator or a customer-focused person, or a consultant, whether you say "lowest" or "most efficient." From an ISO standpoint, we need safe, reliable power. So, they need to run the markets, run them efficiently, and keep the lights on.

From my standpoint as a trader, we have liquidity, creating the ability for hedging, trading--opportunities for me to make money as a trader.

And then, for these capacity markets, where are you getting the revenues out of the power market to create returns for the assets that you have in the market? Are they getting those from energy, ancillary services, or capacity? And then, are you creating appropriate signals for new investment? And what kind of investment do you want? We could have an entire panel on that, but are you creating appropriate signals for investment?

Capacity markets, yes or no? And this is where I refuse to answer the question. So, we have New York, PJM, MISO, New England, and California with capacity markets in various forms. Some of them have predetermined demand curves or capacity values based off either *ex ante* forward looking or *ex post* backward looking valuations of what people consider to be the marginal units. Others of them just kind of let the market determine what the generators need to be made whole, and that's what they bid, because that's what they need to be made whole, and you set a market clearing price. And then we have ERCOT and SPP that are in adjoining markets, and don't have capacity markets.

So which is right? Which is better? That's the question they wanted me to answer, and I can't do it. The temporal and duality gaps that exist in the markets, the uncertainties they create, you can drive a combined cycle plant through. It's such a complex impossible question, from timing and pricing and the lumpiness of the decisions that you're making, that it's an impossible question to answer. So, if you set that question aside and say, "Well, what are the questions that we need to be thinking about?" in my mind, those things are: given the market design that we have, are we making the right choices at the margin for our market designs? Can our markets survive, from the current state that we're in, through the transition state? And that transition state can be Alberta's transition state that they're experiencing. It can be California's transition state, going through solar and wind penetration on a massive scale. Can they transition through to the end state where the storage problem is solved? And, like I said, is that 10 years down the road when we can drop batteries everywhere and solve the storage problem and deliver power when we need it? And in that interim, do we have the right products and markets to reflect what we need to change the market dynamics?

Now, as an economist, my preference is for markets. Make it transparent. Let the markets solve the problem, and if the markets all solve the problem, and there's enough money in all of those markets, their capacity prices would quickly go to zero. Because the bids that the generators are calculating when they bid into the capacity prices would go to zero. But we're not seeing that. We haven't seen that, so far, in the capacity markets that do exist. So, can you get there? Maybe not. As a trader, I kind of like the transparency of prices. I also like the opacity of uplifts in capacity markets, to the extent that I can figure out that opacity better than somebody else. So I'm a little conflicted.

So, we've got all these competing agendas out there. Emission standards, renewable targets, we've got the ZECs, which are an indication that the current *ex ante* New York demand curves going into capacity markets maybe aren't enough for the nuclear units right now. We've got the federal government saying that they want coal and nuclear to get some kind of special treatment, and that's a developing story, just over the next few weeks that people have got to respond to the DOE NOPR. We're hearing a lot of stories about distressed assets, the existing resources not making enough money to survive. We're hearing increased chatter about reliability contracts, a similar kind of concept related to these distressed assets.

It sort of comes back to the question of, well, what problems are we trying to solve? What products and markets are necessary to solve those problems? We can define products and markets and create revenue streams, or we can push these things out into uplift constructs. Capacity is really an uplift construct. The ZECs are uplift constructs. There are various uplift constructs that you can create to solve these problems.

At the coal face, as you look at the markets that are out there and the issues that I think about as I'm looking at trying to project what energy prices are going to be and where I can make money and where there are opportunities in the forward curve relative to where I think things are actually going to settle, wind penetration is a massive deal. So, when we get wind penetration, all of that generation's completely inframarginal. It generally leads to increased regulation or reserve requirements to cover the increased net thermal generation volatility that's needed to cover the uncertainty related to wind forecasts, etc., etc. But our traditional commitment and dispatch models completely failed to value the commitment Lagrangians associated with those decisions.

What I mean by that is that when you need additional regulation or reserves to cover that volatility, you commit the unit, and then you solve the dispatch problem. Well, once you've committed the unit, you've already incurred all of those costs, and at the margin, as you're calculating the prices, the incremental value of scheduling the reserves and regulation is actually very low. So, the clearing prices of the products that we calculate that solve this wind penetration problem don't solve it at all. They solve it from a reliability standpoint, solve it from the ISO standpoint, but from a missing money standpoint, from creating the right revenues and prices and markets to give to the generators, it doesn't solve the problem at all. It just creates additional unit commitments, which further reduce the energy price, and it pushes more of the costs into either daily uplifts, guaranteed payments, net cycle generated costs for generators on a daily basis, or pushes it into other missing money constructs like capacity markets.

For solar penetration, it's similar. It's a slightly different problem. It's not the uncertainty associated with the solar (except whether the cloud's going to be there or not, which is a little), but for the most part, in the markets that have the largest amount of solar, the issue is more getting into the day ramp-up of the solar and the end of the day ramp-down for solar and having enough rampable capacity down and up to solve your problem. So, the duck curve that we talked about in California becomes a goose, the goose becomes a giraffe, and you have that same issue that our traditional market models can't solve, so it pushes more of the cost into the day-ahead market uplifts and make-whole payments or other missing-money constructs, like capacity or reliability constructs.

My biggest concern is that we get trapped in a price spiral. If we look specifically at California, from a trader's perspective, they have decent liquidity in the hubs, mostly in the day-ahead. They're dealing with the Aliso Canyon issue and gas issues, trying to get rid of gas completely, out of their market if they can. They're the market with the most advanced solar and wind penetration issues. And I think this summer, the really hot summer we had really hid the issues associated with this, because energy prices were actually strong enough that they didn't face the operational issues that I think are going to come if we get a summer that's a little less strong. We did see strong evening peak prices, which is reflective of the need for the capacity to ramp up in the evening, but there still is this question of how do you pay for the ramping resources you need when energy prices are not as high as they need to be to cover the full boat of the resources that you need?

At PJM, obviously, it's the standard bearer in terms of trading liquidity. PJM West Hub is absolutely the standard bearer. I would think it trades 40, 50, 100 times more than any other hub anywhere in the US. There's a lot of liquidity in the day-ahead zonal spreads. That's a market that is very, very tradeable, and everybody trades it. The first thing that any trading company will do is set up PJM trading desks, because that's where the most liquidity and opportunity is. But there are issues in PJM. The peak load days are not the peak price days. When you see that high load's coming, real time prices very much underperform market expectation. So, you'll see the market rally with hot weather. The next week product, second week products, will rally as the hot weather comes in, and then, when it actually comes to delivery, it massively underperforms.

Most of us trade on the ICE platform. When you watch the dynamics of the market and how the markets react when certain things happen, when you get hot weather alerts, and they declare extraordinary operating procedures, the market immediately trades low. If you hear that they're going to activate demand response, the market immediately trades lower.

And these are things, to me, that are contrary to the signals that we should want to be seeing. If we're getting into worse situations, we would want to see prices being higher, and that's a strong indication to me that there are issues with either peak unit pricing or demand response pricing, or there's a whole bunch of out-of-market actions that are happening that are unpriced and causing prices to be lower than they should be.

As traders, we see that the opportunities are actually not on peak days. It's the near-peak days, where there are misses in load forecasts, when temperature, humidity, those are where the opportunities are, where there are surprises, and they don't have the resources to recover. As a trading thing, that's great, if we can figure that out before other people figure it out, but it means that the pricing, from a generator standpoint, is unpredictable. If it's unpredictable, it's hard for the generators to capture it. If it's unpredictable, it's hard for it to get into the forward curves. We had West Hub summer trade around $32.50 this year as the July average for West Hub peak. September was $40. That sort of seems a little backwards.

In ERCOT, liquidity's improving in northern Houston. The wind and solar penetration is really cannibalizing prices. So, in general, being short ERCOT is a really good thing to be right now. It's risky because they have the energy-only price, and super high potential tail events that can wipe you out, so it's hard to do. If we don't have capacity prices or capacity markets there, the at-the-margin price decisions that you're making on those few peak days become critical. And this summer, even on the hot, high-load days, we really didn't see the ORDC (operating reserve demand curve) tested. The ORDC is the scarcity pricing mechanism that is supposed to create the value that allows an energy-only market to really work.

The 4CP (four coincident peak) pricing has just absolutely destroyed the ERCOT market. So, we saw demand response coming in on the highest load day of the year. Energy prices were $30 when the demand response activated--$30! And they weren't doing demand response because of energy prices. They were doing it because they were avoiding transmission costs. They were avoiding the four coincident peak transmission pricing.

And that goes to one of the things that I want to really highlight here. You have to be careful about all the market design decisions that you're making. If you're going to go energy-only, you can't let these kinds of things distort your prices, because you're destroying the key underpinning of why you want energy-only pricing as a construct. So, any unpriced out-of-market actions, you've just got to get all of those out of your market.

So, again, the peak pricing days in ERCOT are wind and weather prediction misses. They're not the high load days. And I think that's a little bit backwards, and it means that the generators are exposed to high real-time prices when they trip or create the uncertain events. It is very hard for them to catch value out of the uncertain events. What's going to be really interesting in ERCOT is that there are huge amounts of capacity slated to retire, particularly in the north and east of the system. Some of those units have capacity factors as high as 60 or 65%. Again, to me, that's an indicator that something's a little broken there, and it'll be interesting to see how the market responds, when and if those units retire, and whether they're allowed to retire.

Turning to other markets, just quickly, MISO has really good pricing. Liquidity's increasing there, and we tend to see peak pricing on peak days. They do a good job with their scarcity pricing, and the alignment of prices tends to be pretty good.

Same thing in New York, but liquidity sucks in New York. You can get day-ahead contracts in New York. For whatever reason, the real-time markets have never developed in New York. The only way to get in the real-time market in New York is to buy day-ahead and then virtual bid up from day-ahead into real-time, which then exposes you to massive regulatory and market monitoring scrutiny for manipulating markets. So it's something that's very hard to do.

SPP, still really new, has limited liquidity, plus it's really too early to call what's going on in SPP.

And, ironically, given that I live in Boston, I really don't look at the New England market very closely, and that's because we're predominately a congestion shop, and there is no congestion in New England, because of how they operate their markets. So I don't really know a whole lot about the market that I live in.

So, in closing, both markets can succeed. I was doing some research online before I came here and Gordon van Welie said the exact same thing. But both constructs can succeed, and for me, at the margin, we just want to make sure we have the right products, markets, and prices to meet the changing market needs, and I'm not sure that we do right now. I think that we have to figure out some way of creating a ramp product within our existing market models that allows for the full value of ramping capacity to be reflected in a market-priced product in order to cover all of the transition issues that we're going to have as we get the continued solar and wind penetration in the markets. The full-blown ELMP model is a construct that can solve this problem. It's an uplift minimizing pricing construct that allows for the commitment Lagrangians to get captured in specific products, but that wasn't able to be implemented. It's a very complex thing. We may have to go down that road, and if we don't get down that road, we may see some of these markets and the energy revenues get cannibalized, to the extent that all of the thermal resources are going to require some kind of uplift, and I worry that we get into this price spiral where all of the value of the market gets pushed into these uplifts.

So, are we setting prices appropriately in the few peak days that really matter? Are the prices predictable? Can they get captured by the generators, and are we making other design choices, like 4CP, that are just having really bad unintended consequences in the market? We all need to be watching the retirement/reliability constract issue. There are indicators of problems of missing money, and the more we hear about those in each of the markets, the more we have to look at those market designs and figure out, can we do something to get the right products and create revenues in market structures to solve those problems?

Question: I'm curious about the prices falling when demand response is being called, and the suggestion that there might be some problem with the market design there, in terms of scarcity pricing mechanisms. On of the things that New York, I think, talked about in their summer operating studies for the last two summers, is that they had a small amount of demand response that was happening at the local distribution company level that was outside the ISO price-setting mechanisms. And I'm wondering if you're thinking the same thing might also be happening in PJM, where the local distribution company's calling its own demand response, and that's flattening the load, so the ISO scarcity pricing mechanisms are never seeing those prices, and

I'm wondering if that might be a state-versus-FERC market design problem or issue.

Speaker 3: There are a couple of examples in there. It was two summers ago on one of the peak days in New York when the ISO did not call demand response. The New York ISO does have a demand response program—the EDRP (emergency demand response program). They have an administrative structure that administratively sets scarcity pricing when they're activating the demand response, and when that demand response was necessary to maintain 30 minute reserves. In this particular instance that you're referring to, it was ConEd that was the load serving entity and when the ISO hadn't called demand response, ConEd ended up calling demand response in all 13 of their subzones, and it obliterated prices that day. And so, making sure that whatever demand response is being used is activated at an ISO level is super important.

In PJM, there are two things going on. There's a bunch of out-of-market demand response that's occurring, either through load serving entities independently contracting and effectively self-activating those things, and so the ISO's not seeing them. It's going to become beholden on the ISOs to make sure that their load forecast protocols are actually capturing expected demand response activation, so that they're not overcommitting and creating arbitrarily high reserve margins for loads that aren't going to show up. But also in PJM, even for their inside-the-ISO demand response, there's only a very limited portion of that demand response that's actually eligible to set price. So, if you read the PJM tariffs, the demand response called by the ISOs are eligible to set price, but only a very small portion of that demand response is actually eligible to set price, and so, when that's combined with the small portion of the peaking units that are eligible to set price, it creates an environment where it's very easy for the marginal prices on those very hot days to be much, much lower than you perhaps would want them to be.

Question: I'm a little confused about where you're coming from. In New York, I agree, energy is not liquid, but they actually have a trading capacity market. In PJM, it's the reverse. You don't trade capacity, you trade energy. And MISO is vertically integrated. And let's add that gas prices are so low and there's no volatility in the markets, it's hard to hedge when there's no volatility, yada yada... So, I'm just struggling to understand your perspective. Are you coming from a generator perspective? Fom a banking perspective? I'm trying to understand a little bit more of where your comments are coming from.

Speaker 3: My comments are more coming from a trader's standpoint, I can access the PJM markets because there's full liquidity there in real time. So, PJM West Hub is the most actively traded thing, probably, next to WTI and Henry Hub Gas. You can access those markets, and you can take some of the days in early October in this most recent heat wave, where the day-ahead market was clearing at $39, but it was obvious that the market was massively under committed, and in real-time was clearing in the $60s. So, that's creating opportunity for me as a trader. At the same time, the peak load days that we saw in early July this year traded at up to $60, $70 in the forward market in custom daily products or next week products, but when we actually got into the day, the load cleared at the level that it was expected to, but because we were under hot weather alerts, because there was demand response being activated, we were seeing those days clear at only $30, $32. And that makes it very, very hard, from a standpoint of creating revenue certainty for generation. (Now I'm stepping away from the trader perspective). It makes it very, very difficult for somebody who's thinking about investing in new capacity or thinking about keeping their resource on, where they weren't getting access, they weren't even committed or online in the early October products, because they're taking their outages, or they weren't in the portion of the supply stack that was committed in the day-ahead markets, so they didn't schedule their gas, so they weren't able to operate. It gets very hard for either existing or new generation to want to invest, in that environment.

Speaker 4.
I fear that I was invited to this conference or this panel to be the fly in the punchbowl at the picnic, or the red ant in the potato salad. Before I start, I think it's important to know that most of my focus, but not all, will be on the underlying rationale for the capacity market, which is the missing money that's allegedly necessary to maintain particular reserve margins, because that was the foundation of the problem, and that was the argument that was used by the generators in the debate we had for several years over market design. The second thing to know is that my experience is fundamentally based on ERCOT, which is not all of Texas, but about 90% of the load. And apparently we'll be the only remaining, I think, energy-only market left in North America. And originally, if time permitted, I was going to talk a little bit about my views on Alberta and what they're facing, but I think really the comment will probably be best I think summed up by just saying, "Go with God, because you're going to need it." [LAUGHTER]

So, the answer to the question, "Sustainable Capacity Markets, Too Much to Hope For?" is, yes. I believe the centralized capacity markets are fundamentally flawed. They're built on the extremely weak foundational premise that the capacity market is necessary in order to maintain a particular required minimum installed capacity reserve margin, which, in turn, is required to achieve, in theory, on a day-to-day basis, a minimum level with respect to system reliability. That, in turn is usually based on an equally flawed reliability standard--I think almost everywhere it's one in 10, which itself is grounded on a flawed premise that installed capacity actually relates to reliability.

Second, I think capacity markets actually manipulate the energy markets by maintaining economically unreasonable margins. We'll talk about that a little bit.

And then, the very existence of a centralized capacity market actually, I believe, is detrimental to efficient price formation in energy markets, when what it supports are fundamentally uneconomical reserve margins. That, in turn, is detrimental to the very rationale for centralized capacity markets, which is that they are supposed to maintain system reliability, because it suppresses in-the-market scarcity pricing and price signals, thus undermining the proper incentives and signals that go to both generation and to load.

And then, finally, the use of capacity markets, I think, result in other policies that are detrimental to the proper functioning of energy markets, including the use of artificially lower price caps in the energy market, which, again, is detrimental to the effectiveness of the system and fundamentally to reliability.

The first point is that I don't believe that installing generation capacity does equate to system reliability. That certainly has not been our experience in Texas. The two times that we actually had to go to rotating outages because of capacity, which were in 2006 and 2011, we had very fat reserve margins based on installed capacity, well in excess of our minimum target. And that error is compounded, as I mentioned, by the adoption, in organized markets across the regions of the country, of what's fundamentally an archaic one-in-10 reliability standard, which is kind of odd because, well, the "10" is usually a constant, one something in 10 years. The truth of the matter is, when we went to look at the standard, there's no constant with respect to what the "one" is. It ranges from event to hour, and, in one region, up to 24 hours in a 10 year period. The resulting required reserve margin divergence is material.

The bottom line is that, when we looked at all this for more than a year, we found no credible basis for the one in 10 standard, and we concluded that for a system to provide reliability efficiently, we really had got to incent the right behavior, which emphasizes high operational reliability on the part of generators and rational load response from consumers or their load-serving entities. And we found that this is best achieved by getting the prices right, and by the risk of scarcity pricing.

I'll give credit to Brattle. They did several studies for us during the resource adequacy project. But during the course of that, they mentioned in passing that there are issues around the reliability standard and around the one in 10 standard, and I don't think they were trying to dissuade us from going down the capacity market path at that point in time, but it actually raised a lot of questions in my mind about things like, "Well, what are we really talking about?" And, at least in ERCOT, we were talking about very few hours out of 8,760 hours of a year. A handful of hours, usually less than 10. In my conversations with the legislature, I always goosed it up to 15 or 20 hours in a year that would be the risk, which was way overinflating it, but I wanted to be on the right side if an event actually happened. The truth of the matter, at least in Texas, is that we have many more hours of outages on the distribution system because of weather. We have ice, we have snow, we have thunderstorms. The derecho, or whatever it was called, up in Ohio, the Midwest a few years back…down in Texas, we just call that "weather." That's what happens every spring and summer and fall.

As a result of the study, we decided that neither reliability standards nor target reserve margins are necessary, because the energy-only market, with the threat of high scarcity prices, will produce the optimal market-based reserve margin. My policy advisor went back and really dug into the question of where did the one in 10 standard come from. He couldn't find it. What he did find a lot of work done in the '20s and '30s. Even at that point in time, they couldn't point to a real rational basis for the standard. And so, we ultimately determined that we would have no reserve margin, but instead ERCOT would publish the expected economically optimal reserve margin, and also what the expected equilibrium reserve margin would be, and we would just publish those results to give the market a sense of where we were, and we felt that was a lot more effective and efficient than an arbitrary number that was not based in anything. We expect those results to be converted into an expected unserved energy value, again, in order to inform the Commission as to where we are from a risk basis in terms of the costs and benefits of certain actions.

As I said, I think capacity markets adversely manipulate the energy market, and are tied to unreasonable reserve margins. They reduce energy prices. We found by experience that they were reducing operational reliability by removing the positive and negative incentives to improve unit performance. The best example of that was February 2011, when we lost a huge amount of generation--again, with a fat reserve margin in installed capacity. Had we had a capacity reserve margin that was, say, maintaining 15% or 16% reserves, we would have been paying for a lot of insurance that was absolutely worthless, because units just weren't ready. It was unusually cold, even by Texas standards, for the winter. But a capacity market would not have prevented the outages. In fact, the subsequent day and the next days and the next week were even colder, yet unit performances dramatically improved. Why? Because on one day alone, there was at least one generator where the generating company lost $30 million in a day, and that was when prices had an effective cap of $3,000. That had a tendency to wake people up and get them ready.

The same thing applies to load serving entities. When you have low energy prices that are constant, without the risk of high prices, load serving entities get lazy. It reduces the incentive for them and their customers to invest in load management programs and hedging activities, if the load serving entity and their customers are required to pay for a mandatory reserve margin that has the effect of keeping prices artificially low. That discourages activities to manage that load, and perversely, I believe, incents reduced investment in load shaving technology and programs. It reduces the use of load management tools and smart meter technology. And it reduces the use of hedging. We found that out in West Texas, for example, which for a long time was what amounts to a negative load pocket, because that's where all the wind was being built, yet the west-to-east transfer capacity was limited. It was constrained. Therefore, all this wind was sloshing around, and prices were very, very low. As a result, load serving entities and their customers weren't hedging. Why would they? Why buy fire insurance when it's raining all the time? People just weren't managing the risk. Then, as the CREZ lines began to be energized, and the power was flowing out, they had a double whammy of prices rationalizing upwards at the same time that there was an explosion of oil and gas load in West Texas. They suddenly were faced with really high prices and congestion costs, and they were going, "Why is this happening?" They were warned, but people just didn't take action, because they didn't think there was a risk. And that includes their load serving entities.

To elaborate a bit more, capacity markets produce policies that are detrimental to energy markets—detrimental both to energy market price formation and to operational reliability in the sense that loads, if they're not investing in control technologies, they're not able to respond to the prices when they get high. One of the activities we noticed that followed the very high prices in August of 2011 that happened because of the drought, when the system got very, very tight, is that there were load serving entities, for example, that thought they were fully hedged. They weren't. And they lost a lot of money very quickly. Subsequently, they decided, "Maybe we ought to explore using these advanced meters and other technology, and also innovative load programs--like free nights and weekends--either to shift our load off-peak, or to get customers to sign up for their own load management programs." It incented a lot of the right behavior. And, again, the risk of scarcity pricing, is largely mitigated in a capacity market, because capacity markets are usually based on an unreasonably high mandatory reserve margin, and that's exacerbated, to a certain extent, with the way those markets are designed.

And so the bottom line is, for a market to really provide system reliability efficiently and effectively, it's got to incent the right behavior. It's got to incent high operational performance by resources and the proper behavior by load serving entities and their customers. And at least we found that this is achieved by exposure to the risk of high scarcity pricing.

You get back to this question, "Well, really, is there missing money?" I will concede there's missing money if you keep artificially low price caps in the energy market. Why hedge if you don't feel any risk except once every 10 years? But the reaction is, "Well, we can't stand the political risk, the headline risk, from \$3000-\$8,000 prices." What I've never really understood is why or how is there a political risk to that problem, particularly around a price risk that can be hedged and managed, versus the political risk that comes from a very high capacity payment that is completely unhedgeable? That just becomes a bill that has to be paid. When that's explained to me, then perhaps we can revisit this issue.

Going back, again, to ERCOT, to sort of wrap things up, our experience is that operational reliability, which is much more important than installed generation capacity in terms of keeping the lights on, even with otherwise high installed capacity levels, operational reliability can deteriorate very quickly, and then improve dramatically in response to efficient price signals. We believe that a market-based approach providing proper scarcity pricing will incent generators and load to provide the consistent operational reliability across the system that's required. The increase in our system-wide offer cap and the implementation of the operating reserve demand curve and the resulting improvement, I think, in scarcity pricing was a critical component to achieving that. Because it's the exposure to the risk, and I want to emphasize exposure to risk and not the actual experience of high prices, that incents the owners to invest in proper maintenance for their plants and training of their operators.

And, similarly, larger load serving entities are incented to invest in a variety of programs to manage their consumption, both because of the opportunity, in many cases, to monetize that, but also to act as a physical hedge against the odd bad days.

And at the end of the day, in talking to the management of some of those companies, it also just helps their customers get sticky. If they're offered a dollar a kilowatt to join, or if they're offered, "Look, if you sign a two-year contract with us, we'll give you a Nest thermostat [or whatever the whiz-bang technology is], and, by the way, if you do that, you can sign up for our DR program or reliability program, and, oh by the way, we'll pay you a dollar a kilowatt for every kilowatt that we reduce when and if we call upon your program." It turns out that a lot of those load serving entities that have those programs that they originally invested in in order to manage the risk are now also using it to manage their congestion risk and their transmission cost 4CP, (which I will concede is an issue, and, at this point, we're looking at it, but allocation of transmission costs in Texas is the fourth rail of state government).

I keep a file of quotes from other RTOs, and I love the one, after the polar vortex from their IMM about the winter issue: "Incentives are clearly not adequate, a 40% outage rate is unacceptable, incenties need to look like an all energy market." So, to wrap it up, yes, I think that the capacity markets are fundamentally flawed, and to paraphrase the comments made before FERC, from an obscure academic from an equally obscure Northeastern academic institution, "Life is too short to spend it trying to fix capacity markets," and I decline to identify the commenter in order to protect the guilty. I look forward to your questions.

General discussion.

Question 1**:** Just to quickly stir the pot a bit, let me ask four questions to the panel, and then we'll kick this off. So, what's the issue? Is there an issue? Can it be fixed? And, therefore, is it sustainable? And those are the questions I want to throw out as the theme, and there are a couple of question that we raised as a panel that I want to talk about, like fixing prices and whether we need to go with the minimum offer price rule, the MOPR, and what's happening with uplifts, and do we have the wrong products, and are we buying too much? A

But I want to start with the theme that was in the questions that was provided, which is, what is the issue, and how do we deal with the issue of subsidized resources?

Respondent 1: I loved Speaker 4's talk. I think I'm, from a principled standpoint, right on the same page as him, but what I see, is that we're just continuing to see a constant stream of indicators right now that resources are struggling. You've got the ZEC (zero emissions credits) debate for the New York market, which is really just another targeted capacity payment that suggests that the existing capacity construct is probably some simple cycle gas peaker on the margin in the New York, and that the revenue calculations associated with it just don't correlate to the nuclear units anymore, because their baseload and their energy revenues are getting absolutely destroyed by the renewable penetration. And I think that the reluctance in a lot of the markets to get rid of capacity markets right now is that they feel like if they did, that there aren't enough revenues out there and they'd have to be OK with letting a lot of things retire, and until we can get the politics and the ISOs to be OK with operating at lower reserve margins than they've traditionally been allowed to, or been comfortable doing, and with letting the prices accelerate in the way that they would need to in an energy-only type environment, bridging that gap…it's almost unimaginable.

Questoner: So, is there a fix? Is the minimum offer price rule, is that one way to fix it? Or integrating the subsidized assets into the pricing so that we make sure that the prices are reflective? Like, is there a fix?

Respondent 1: You're saying minimum offers in the capacity market? I don't think fixing the capacity market is the problem. I think the problems we have right now are a function of the fact that gas and coal are right on top of each other…the generator economics. Instead of a decent number of the generators making margins, relative to the marginal unit, you've got the entire coal and gas fleets sitting on top of each other. You've got nuclear resources' revenues being cannibalized by wind in the off-peak and solar in the peak. And so you have that missing money, and what it's indicative of is a market that's got more capacity than it needs, relative to the existing clearing prices, but an unwillingness to go below the existing reserve margins. So, you have to be prepared to reduce those reserve margins, and that's really the only fix. It's not fixing capacity. It's really changing what people are comfortable with.

Questioner: To some of the other speakers, do you want to take the other side of that? I know you talked a bit about the MOPR. Is that a solution? Is that a way to keep the capacity market working?

Respondent 2: A lot of the motivation for these state-specific policies is that you're kind of pricing attributes of these technologies. For example, the classic indoctrinated economist side of me would say, "You should price carbon if that's kind of a really important aspect, such that you're trying to subsidize these low-carbon resources." Part of me would just say, again, as people talked about in the earlier panel, that's also complicated, but you could price these attributes specifically and mitigate some of these issues. But, I guess, getting to the MOPR and the PJM and ISO New England designs, I think it's a way to mitigate the problem, but I think the fundamental problem is if we have different regions with different incentives. If you believe that you should price carbon emissions, that would alleviate some of the issues, and you can price carbon and lower the nuclear subsidies, etc., and that would mitigate a lot of the issue. So, being a supporter of carbon pricing, I would say that mitigates a lot of the problems.

And then, with respect to the PJM and ISO New England minimum offer pricing rules, these kind of multistage approaches to mitigate the issues of dampening the price signal in the capacity auction…I mean, it's hard to not believe that those are kind of Band-Aid approaches to mitigating the problem. Will they work? I think they could solve some of the issues of mitigating the price effects, but I guess the fundamental problem with the nuclear, for example, is pricing the value of carbon emissions. So why not price carbon emissions and get rid of the issue? But I understand there str political constraints with that. I guess I'm not quite answering your question.

Respondent 3: I think it's interesting, because, as I said, we've been in this very simple market in Alberta--energy only. We knew that in an energy-only market we could never incent a nuclear facility, because the capital investment is so long that it needs more political stability and contractual stability, and the same with hydro, large hydro, anyway, in an energy-only market. So, even there, you aren't able to incent all the types of investment that you might want to, but there is enough of what we wanted to invest in that it kind of worked.

So, to me, energy-only is least cost. If you're going for least-cost fuel, energy-only worked really well. And when you add in the environmental markets…The other thing that we didn't talk about that's actually kind of important to know about Alberta is that not only do we have a $30 carbon tax, but they're going to set what they call the "performance standard" at the level of a brand new CCGT, which means a brand new CCGT, or anybody who has an emissions factor below the CCGT, will not pay the carbon tax. So, that's another sort of design element, where I'm not sure it was designed with our electricity market in mind. It was designed for carbon policy reasons. Those markets have to work together.

I think it goes back to what are you trying to incent. Have you developed the products to do that? Any time you're adding subsidies in anywhere, you're distorting the price. And if you're distorting the price, you're moving the balloon around, and you have to fix the unintended consequences that you create. So the question is, can we go to those pure forms of markets that economists all dream of, or do we have to accept that this is not perfect, incomplete, and choose between those incomplete or imperfect structures that we're creating?

So, do we need a MOPR? I don't know if we need a MOPR, but we need something. We have to try to keep the signals going the right way. If we want to continue to believe in markets, when we get frustrated with markets (and I'm sure we're not the only ones that say this), we put up our hands and say, "Let's just re-regulate, because this doesn't make any sense. Why did we do this in electricity?" I've heard that since markets have deregulated. Should they have been deregulated? Was it a good idea? And is this experiment working? So, it's bigger and broader than just the discussion about a capacity market.

Question 2: I just wanted to comment on this MOPR discussion. I think when you have a really concentrated market, whether it's Alberta or even the capacity markets in PJM, you have to be very careful about the rent-seeking aspect of the subsidies, in that the MOPR is basically allowing something that is actually prevented by the market power mitigation rules in the capacity market. So, if I were a large generator in PJM, I would be thrilled to have 2,000 megawatts. I'd like to actually bid it out of the market in order to have higher capacity prices in my region. And, in fact, if I can get those higher capacity prices and get the state to pay me for the generators that I'm withdrawing from the capacity market, that's even better. It seems like there's a fair amount of return on investment from lobbying for pursuing that kind of strategy.

Respondent 1: That sounds like a perverse incentive for retirement. We ensure that there's at least a minimum price.

Respondent 2: This goes to this question of whether somehow retirements are bad things. If that were the case, then the market in ERCOT would have been dead in the middle part of the last decade. They restructured the wholesale market in '95. Between '98 and about 2005, (and this is when the system was smaller, too, in terms of load), we probably saw 16,000 or 17,000 megawatts of old gas steamers retire. Now, we had a lot of new combined cycles coming on, which back then had the extraordinary heat rate of 7.5, but we had a bunch of gas retire. We had a bunch of new coal come in, too. That's because gas prices were high.

But I would submit that the retirement of units actually shows, in many cases, that the market's working, that it's pushing the old stuff out, and new stuff will come in with different characteristics, but it's not on the back of ratepayers anymore.

The one thing I found out in our part of the regulated space is that the regulated utilities, they're happy to do anything as long as they recover the cost, and they're even happier if they can classify it as an investment. That way they earn a rate of return on it, to boot. But meanwhile, the people who pay for it, the captive ratepayers, have no real choice in the decision of whether it's wise or not. Instead, it's unelected bureaucrats like me or, God forbid, elected bureaucrats in some of the other states. [LAUGHTER] I don't know which is worse.

Question 3: First of all, thanks, Speaker 4, for the defense of energy-only markets. As a former regulator, I appreciate regulators who are willing to do that, and in general, as an economist, I support trying to go in that direction.

I have just one short comment about MOPR, since you brought it up, which is that this has been used in a way that's largely a fiction in the US, in the sense that it assumes a kind of demand-side market power that doesn't really exist in many instances where it's been attempted to be invoked. And so I would urge you to look at Chairman Bay's comments about the MOPR, and treat that with some caution as a mechanism.

I also think it's important to try to actually price carbon and get away from some of the subsidies, but it strikes me that the move towards capacity markets and more capacity payments is, in essence, going in the opposite direction from the way the broader technology in our economy is going. We are becoming more and more involved with distributed intelligence. We see explosions in the amount of connected smart devices that could respond to prices. There's still some uncertainty, but we are seeing a potential real expansion in the use of electric vehicles, which is both flexible demand and will impact your demand requirements here in Alberta. And we're seeing many utilities in the US and Europe beginning to offer connected home devices to their customers, as well as many marketers in Texas and other places doing the same thing. And it just strikes me that technology is moving in a way that makes demand much more flexible, and I really didn't hear much discussion about the flexibility of demand in this panel.

It seems like much of the panel is operating from the historical assumption that demand remains inflexible when, in fact, I think we really underestimate that capability when we think about how we're designing markets. And, quite frankly, in the US, we don't do a great job of pricing that at the wholesale level, with the way we settle our wholesale markets, but that's a whole separate topic.

Respondent 1: Just to broaden the question, we've asked the panel whether the capacity market is sustainable. But maybe the broader question is whether we're facing a structural change in the marketplace as a whole that's significant enough, with distributed energy, and we're finally at the world of smart meters and we're changing the grid in terms of electric supply. There are so many changes. How do you even measure, on the wholesale level, the dispatch of assets that are on the distribution side and are quite small? Maybe the question isn't just, "Is it sustainable?" but, "Are we at a point of such structural change in technology in a future world that we need to rethink this structure, the market model as a whole?"

Respondent 2: I don't disagree with what you're saying. I think another complication is, how do you treat these distributed energy resources in a capacity auction? I'm not really answering your question. I'm more raising the point that, with the growing penetration of DERs, I think it's going to be even more complicated in a capacity auction framework. Because if you have big demand response, you can do demand response aggregators. You could maybe do DER aggregators in a similar way, and they could participate in a capacity auction. But, again, is that necessarily the right approach? So, I think the growing DR and DER framework is challenging.

To comment on the DR framework a little more, for example, PJM, with the polar vortex, they redesigned their capacity performance measure, and that affected the treatment of demand response and renewables in the capacity auction. I think it will be interesting to see what happens going forward. So, yes, I think the DR and the DER make it particularly challenging, and add to the value of price signals as renewables grow, demand response grows, and DER grows. The value of price signals in the energy market is just becoming even more important, and if we believe that capacity auctions mitigate these price signals (and, again, you can debate both sides), then that kind of goes in the opposite direction. But, on the other hand, there are tradeoffs with the energy-only market design. There's no silver bullet, in my opinion, but I think there are tradeoffs in both market designs. But I guess I'll summarize to say that growing DER and growing demand response is going to be challenging in a capacity auction framework.

Respondent 1: So let me change the question slightly. Maybe just look at net demand variability. You don't worry about who's behind the grid, the wholesale grid. You let it just fluctuate, but now that creates need for ramp, and maybe you then figure out a way to ensure that there's pricing for flexibility, whether it's in the energy market or in the ancillary services market, through a ramp product. Do you want to talk about that a bit?

Respondent 3: Sure, and I want to look back to the original question, as well, because I think I agree with you, that it's already here. One of my colleagues in my broader energy company is doing exactly those services in the ERCOT market. It's pulling together demand response, smart meters, ramping, air conditioning in homes. This is how I discovered 4CP, actually. Mostly they're doing it to control, not energy prices, but to avoid the transmission charges. But, for whatever reason, they're doing it. It's here. The technology is here. The aggregation is here.

And so, the question as you posed it and as it relates to the ISOs is, we've got to figure out how to get all of that information and data plugged into the ISOs. So, the fundamental problem we have right now is that the ISOs are still sitting in their traditional way of thinking about things, which is that every hour of the day, they do a load forecast. They say we need X plus 12%, or X plus 2,000 megawatts, or whatever their nomenclature is in their market, and they go and they do it. And they do it without fully understanding all of the things that you're talking about that are now plugged into the grid. And I think that until the ISOs start focusing on how to plug all of these marginal incremental things into the system and loosen up a little bit on their X plus 2,000, or X plus 12% at the margin on the five minute pricing and the hourly pricing and the daily pricing, until we solve that problem, we're always going to have the missing money, because they have this natural propensity, and rightly so, because it's in their mandate, it's in their documents, that, "We must be reliable, we must keep the lights on, we must…" It's all written in there, and so they do it. And we've got to figure out a way to get all that stuff plugged in, and then loosen up that mandate a little bit, so that we can allow the prices to get where they need to get, and then capacity prices will go to zero as a natural result of that, because there is no missing money anymore.

I don't have an answer to the ramp product question yet. There are probably a lot smarter people than me who need to figure out how to integrate that construct into the existing market models. So, maybe we can get there, but it's a problem that, while potentially solvable now, with the advances in computing power and everything else, again, it's not politically palatable to have the discussions about changing the pricing construct in a way that's necessary to find that missing money, and then you've got to charge it to somebody. And then you're going into people's pocketbooks, and now you're back on the fourth rail trying to allocate costs that people don't want to pay.

Question 4: I want to piggyback on some of these comments. You described the technology of distributed energy resources and flexible demand, and I agree with that. That's changing, and the future is different than the past. The other thing which is mentioned here frequently is the arrival of intermittent resources that are going to be much more fluctuating, and that's coming, and it's already here, and it's growing bigger. These two things both have in common that they make it not less important, but more important, that you get the prices right in the real-time markets, so that you actually tackle the problem we're trying to tackle that Speaker 4 told us about, the real reliability problem. And when you get down into the actual market, like this one that's turning the lights on today, the capacity market is too late. So it's not going to help. So the mistake that has been made for at least a decade in this conversation, which drives me crazy, is the assumption that these things are mutually exclusive. So, people say, if it's too hard to fix the one thing, I'll just get a capacity market and solve the problem. That is not true. They are not mutually exclusive, and so, my view of this is, if you don't have a capacity market, you need good real-time pricing with scarcity pricing, and if you do have a capacity market, you need good real-time pricing at scarcity pricing. [LAUGHTER]

The capacity market might be optional, and it might turn out that if you get good scarcity pricing, it'll drive the capacity revenue to zero, and then the problem goes away. And if it doesn't, then OK, but the point is, you need that, so it's a *do both*. It's the belt and suspenders, as I called it years ago in front of FERC, and yet we constantly get this story, which is repeated over and over, "This is too hard, I'm going to focus on the capacity market. This is too hard, I'm going to focus on the capacity market. And when I get the capacity market right, then I'm going to go fix the scarcity pricing." This is the backwards approach to this problem. It is completely missing what the underlying problem is, and the trends in technology, the trends in the mix in the economy, the trends in everything are making it much more important to get these prices right in real time.

So, don't get caught into this dichotomy that now that we have a capacity market, we don't have to worry about the energy market anymore. It's not true. You're going to have to worry about it much more, and if you don't get those prices right, all this technology is going to turn out to be a great regulatory scam, because what are people going to be doing? They're going to be spending their time using that technology to avoid the cost transfers of the 4CP transmission cost allocation when the system is actually not constrained. And they're just going to be spending real money to shift the cost onto other people, and that's the only thing that's going to be. That is not what we should be doing.

Respondent 1: I'm going to take the response as a "Hallelujah!" and I'm going to move to the person who is next on my list.

Question 5: First of all, I like the discipline that energy-only markets create, the pricing discipline, because you need to be careful what you wish for with capacity markets. One of the things that's been talked about is the MOPR price rule. In fact, an important component of that is the limitation on how much capacity can be subjected to the MOPR. And in ISO New England, it's actually been tinkered with, or tended to be tinkered with, by a number of states who want to insert their own policy preferences into the capacity market. And if it weren't for that backstop of "no more than this amount of capacity" (I think it's 200 megawatts the first year), if it wasn't for that, we'd be flooded even more with capacity than we are at present.

It turns out that if we dropped two nuclear reactors in the area, we asked the question recently of ISO New England, if there would be a capacity issue if that happened, and they said, "No, we've got way more capacity than we need." So, the market is tough to play with, because the price signals are wrong, and the information that the operators or restructured market generators see, wants them to do certain things, but in fact, it may not be optimal for the regions.

One other comment is that it's a mistake to think of capacity markets like ISO New England, with six states, as something that's monolithic. It isn't. There are six different sovereign entities, and they're all there with their own preferences and their privileges and their constituents. It's like herding cats, to use that analogy. So, with capacity markets, I don't know, I think you introduce a lot more problems than you need to.

Question 6: I greatly appreciated Speaker 4's very straightforward presentation of the argument for energy markets, but my question is, how does that viewpoint that you have integrate or not integrate the operating reserve demand curve? It seemed to me that was a pretty big change that was put in place in Texas, and based upon what you said, I couldn't really tell how that would fit into your viewpoint.

Respondent 1: One problem we were having (and it was a major problem) is that, whether it was loads responding to prices or whatever (and this was when $3,000 was our offer cap. It had gone from one thousand to three thousand, ironically two days before the ice storm of February 2nd, 2011), you literally went from low to high, and then, whether it was ERCOT actually deploying more resources or what, the prices just cratered. And there was no mechanism for valuing the real value that's provided by your undispatched capacity.

So I suppose you could claim, "Well, you've already tinkered with the energy market, because you're suddenly arbitrarily increasing your prices, because of paying some of the undispatched units when conditions are short and adding it to the energy price." But the truth of the matter is that all we're really doing is valuing the real value that comes from that stuff being online, because it's spinning and undispatched, and it's only added when you get to a certain point that, based on a mathematical formula, it says, "At this point, your loss of load probability in that given five minute interval has dropped below a point where the number becomes positive." And so, now, that capacity that's actually available has value, based on the value of lost load.

So, yes, it is, in a way, an arbitrary addition, but it's valuing something that's real, as opposed to the installed capacity that a capacity market obtains, and obtains three years before you get to the point, and, as PJM and others have found, it may or may not be there on any given day to keep the lights on. So, that, to me, I could justify both to myself and anybody, by saying, "What you pay for in that incremental ladder that's added into the energy price, it's providing real value at a time when conditions warrant it."

The other thing, and this is important, is that it is in the energy price, in every five minute settlement. That's important, because it can be hedged. It can be evaluated forwards. Whether you're Exxon Mobil or a small retail provider, you can factor that into your hedge, and you can contract around that risk. Whether it's capacity payment or its ugly twin brother (or sister, I don't want to be sexist), the uplift charge, in that it occurs from out-of-market dispatches by RTOs, that's not able to be hedged. That's just an out-of-left-field hammer that swings down and knocks you off your seat. So the important distinction is that it puts the value where it should be. It's actually in the energy price, which then in turn sends signals to the forwards. It's what creates the risk. It's what drives the load behavior on the load side to say, "OK, I've just signed up this amount of customers, and they wanted a fixed rate for a year, two years, whatever, I better go out and lock in my price."

Questioner: So, it is something then that you would still need if you had no price caps?

Respondent 1: That's a good question. Notionally, I think not, but probably as a reality, yes, because it does two things. It provides a warning track, and it smooths out the increase, although on a relative basis.

The other piece that I think is important, is that it also distinguishes between economic withholding and not. If you're withholding because you're trying to be pivotal and drive the price up, you may or may not, depending on your unit, get anything for it. If, in fact, prices have gone high because the reserves are really low or getting low, then, you know, it's not necessarily economic withholding.

Questioner: And just one final question. Is it an important enough distinction that when people ask what the models are that are out there, shouldn't ERCOT be described as an energy market with ORDC, instead of just as an energy-only market? Because it was energy-only, and then it changed to an energy market with ORDC. And if it's important enough, shouldn't it be described that way, as a model for other people to follow?

Respondent 1: I don't know if that's the right way. The mechanism's in the energy market. It puts the price in the actual energy, real time. So, I think, from that standpoint, it's still an energy-only market. The revenue will only come from the energy market.

But you could call it whatever you want. Including crazy.

Question 7: Speaker 2 mentioned that TransAlta is going to convert 70% of its coal fleet to gas by 2030.

Respondent 1: TransAlta is going to convert its entire coal fleet to gas in the early 2020s.

Questioner: So, is that coal fleet, or the majority of the coal fleet, adjacent to or within close proximity to, gas pipeline infrastructure?

Respondent 1: Well, currently, it sits right on top of a lot of coal. [LAUGHTER] We are looking at several options. There are lots of pipelines in Alberta. We have a tremendous amount of gas that we're trying to find homes for today. Probably our biggest impediment, in terms of putting a gas pipeline in, is going through the entire regulatory process, not how far we have to build pipeline. We don't have similar problems to NEPOOL (the New England Power Pool), where you have intermittent suppl,y and having firm gas is an issue. So, it's a different issue here in Alberta. We've already winterized, so we don't have the polar vortex issues that you guys had on the East Coast, because we're already fully winterized. We don't have to worry about freezing pipelines and freezing whatever. We're ready for minus 30, minus 40…bring it on. We get those temperatures lots of years, anyway. We have a pipeline now to our gas facilities, but it's really services just starts, not full capacity. So it's a matter of either expanding that pipeline, or there are at least three different ways we can bring pipelines into that area.

Questioner: And you're not worried about stranded investment, because your coal plant converting to gas can't compete in the market?

Respondent 1: I guess that's all about how long of a life you expect those facilities to have. A

Questioner: And that plan is not a question of having an energy market or an energy and capacity market. That's a question of public policy pushing for reduced carbon>

Respondent 1: Yes.

Question 8: I just want to return to the starting point here, which was the sustainability of the capacity markets. I appreciated the discussion of energy-only markets and the contrast with capacity markets. But, at least in my mind, it left a bit of a misimpression.

I'd like to see if the panel agrees or disagrees or can correct me on this, but, really, when we're talking about threats here, we're talking about subsidies. And the subsidies can be pretty far-ranging. We could be talking about subsidies to protect a tax base for schools. We could be talking about subsidies that are really motivated by wanting to protect high-paying jobs in rural areas where power plants tend to be located. We could be talking about, even, a bill that was introduced yesterday in Ohio, which gave retaining a corporate headquarters in a particular town as a justification. And then there are downstream jobs associated with mining, and things of that sort.

So, when we talked earlier this morning about pricing carbon, I think that's an incomplete solution, at best, when you really look at the problem, and the cynics (I'll count myself as one of them) would say that a lot of the policies we're looking at are being labeled as policies in favor of zero emissions, at least in the PJM environment, but that is a pretty thin fig leaf for what is really something else, along the lines I just described, that's really motivating policy makers to make those kind of choices. But that's really an aside.

The point I'm trying to make, I guess, is that any time you have a subsidy that is either retaining uneconomic supply or inducing new uneconomic supply, you're creating excess supply. I think that's fairly axiomatic. And what follows also, fairly clearly, I think, is that excess supply is going to put downward pressure on price outcomes. The point, I think, is that it's going to appear in any organized market, whether it's one that's organized as an energy-only market or not, as long as it's a market where you're relying on the market for the resource adequacy function, where you're relying on the market to manage bringing in resources and exiting resources.

With these kinds of subsidies, it doesn't seem to me to matter whether you're an energy-only market or a capacity-and-energy market. As long as you're a market where you're only using organized markets to optimize that portfolio that the state has already established for you, then these subsidies are going to be a problem. So, I've learned a lot, to be honest, about energy-only versus capacity markets, but I wouldn't want the impression to be left, given the context of the discussion here around threats and sustainability, that this is the key distinction. I'd submit that any organized market that is charged with the mission of managing resource adequacy, ensuring that you've got resources when you need them, is going to be threatened these kinds of subsidies. And so, am I missing something? Or am I just catching up?

Respondent 1: The fundamental flaw of the capacity market actually would be fixable, to a certain extent, by focusing on the reserve margins, because most of the problem arises out of unrealistic reserve margins. And I don't know what it is in PJM, for example, but if you had a 10% reserve margin, or something, you could still have a capacity market, I suppose, but if you just procured less energy, would you have the same problem?

Questioner: Not only do I agree with you on that point, but it's exacerbated in PJM, because the reserve margin doesn't set the cap on what we buy in the capacity market. The way the design in the market works, you buy over and above the reserve margin. So I think that's a very valid point.

Respondent 1: That then flows the question of, if you set a higher threshold, would the subsidy have the same impact?

Questioner: It's an interesting question, but it seems completely inconsistent with the experience we're having, where we have every market signal in our environment screaming for retirement. And, as you said earlier, retirement's not a bad thing. We have people that just will not retire. They do not want to retire. They're defining their resources based on the life of their operating permit, or their useful life on the books, or some other criteria other than their economic life. And when you're confronting that challenge, I don't think it matters what kind of design you've got. You've got political problems.

Respondent 1: I've always thought that there should be a panel on the reverse psychology of the power and utility business, because unlike any other industry that invests billions of dollars on the come, they put their own shareholders' money at risk--whether it's Dow Chemical on the coast, or Exxon Mobil, or whatever it is. There's still this mindset, in large parts of the industry, perhaps because they came from the utility space originally, that risk is a bad thing.

Respondent 2: At least in Alberta, when we had the energy-only market, as soon as there was any discussion of anything of any magnitude where somebody was receiving a subsidy, we were all like pufferfish. As soon as you start down the road of subsidies, the view has always been that you can't stop. Once you put a subsidy in, you are undermining the investment signal that we had in

Alberta to invest without any contracts. And so, it becomes a conversation about, in order to invest, what kind of certainty do you need that the market isn't bringing? So, if the market is very pure and it's stable, then you're happy to take those investment dollars and put them into the market. As soon as you see a lot of intervention…

I always think about electricity, and I just can't even compare it to oil and gas. Oil and gas is a North American or a worldwide market. Every state regulates its electricity. I mean, even energy-only and capacity markets, these are highly regulated markets--highly regulated in comparison to other commodities. So, we already live in that regulated space, and when you're in that regulated space, there's a lot more of your fate, as someone investing, that you have very little ability to manage. Political risk is much harder to manage than market risk. Companies are quite comfortable to take the market risk and the market swing, and they look at the mechanisms to hedge that risk over time, but you cannot hedge political risk. And electricity has way more political risk than the rest.

Respondent 3: In terms of what we call the ERCOT market right now, what it does is it actually fully values the operators' actions, the market operators' actions that they're prepared to take in the five minute market to get what they need to get to solve the problem. And if it's very tight, they're prepared to pay a lot of money. And it wasn't the first operating reserve demand curve in operation in the US. I was in the room when the first one came into being, and it's a less extreme version, but it's exactly the same, in the sense that it was valuing the operators' actions in the actual five minute market. And it existed in a construct where we had $1,000 offer caps in New York, in part because of capacity markets and market monitoring and all those other sort of social things and externalities that you're trying to put on there. And it was a case of thinking, well, if we're prepared to buy $1,000 imports to obtain 30 minute reserves, and in order to obtain those 30 minute reserves, we would need to, at the time, turn on close to a $500 gas turbine in New York City to create those reserves, then the gap between what you need to turn on and the $1,000 is $500, and that's where the operating reserve market for 30 minute reserves started coming from. And you talked to the operators and you said, "Well, what decisions are you prepared to make?" and this is about getting the real-time prices right and making sure that all those actions are consistent. And if you start at that very simplest five minute dispatch rule, and you say, "Let's make sure we get all the prices right for all the actions that we're prepared to take to get whatever it is we need to keep our system running and safe, and let all those prices flow through," we can get there.

And I think, in its purest form, that's what the ERCOT energy-only market is. We need to get all of the other markets to get closer to that. So, we need to get rid of the offer caps. We then need to value operating reserves at the amount that the systems are actually prepared to pay, so that we can get the prices up to the levels that they need to be to do what we need to do in these markets, and hopefully then avoid all of the other subsidies and side payments and uplifts and everything else that exists.

Question 9: Just a couple of quick comments and then a question. First, I really appreciate the conversation about the questionable value of capacity resources and the question about whether or not a given resource will actually be available at the time they're needed. Obviously, that's a problem, because you're relying on those resources to show up. The second point is that there are subsidies from all sorts of angles in the energy space, whether it's the utility sector or gas or coal, and, obviously, the most visible ones are the easiest ones to take down sometimes, but subsidies are everywhere. They are among us, and they can be very hard to remove entirely, so I think it's probably better to figure out how to best manage them, rather than to live entirely without them.

And then, I have two quick questions. One of the panelists noted that high prices allow hedging by all sorts of customers. I think that's fair, but, as noted earlier, with the increase in new technologies available, I think there is a question of whether more aggregation in a capacity market--for demand response, for example, or for storage--could be possible, and price alone can be a somewhat difficult mechanism to ensure that folks can aggregate those. The obvious example is electric water heaters, which could potentially supply a significant capacity resource.

And then this is just a clarifying question. I heard that Alberta's moving away from coal, but moving towards gas, and I wonder…the prices that we've seen just south of the border here for wind are significantly cheaper than new combined cycle gas…

Respondent 1: What we're seeing is increasing demand elasticity in the market. And I think part of it is being reflected in 4CP, but I would submit that a lot of the investment is actually made to manage the price risk, and then, once you invest the technology to do that, to aggregate your customers to offer them various tools, well, then you look around and say, "OK, I've made this investment, how do I use it?" And the one that you can use all the time is 4CP management. So, I don't know which comes first, but it is an ancillary consequence of what we're seeing on the 4CP side to a lot of load serving entities, and it began in the industrial space. But the large commercial space, the Walmart's, the big box stores, they're doing it. And there are several larger ones that now offer HVAC repairs…a lot of other ancillary services in which they will come in and say, "Oh, you need a new water heater, we'll put that in, and oh, by the way, have you ever heard about this or that."

Now, it's in the early stages, but ERCOT already believes that they've got north of 2,000 megawatts of price responsive load out there. Unfortunately, it's not in the market, in the real-time market, bidding, in yet. It's not in SCED. There are various technical problems, but that's where the system is going, and I don't think that will slow down any. We're seeing a lot of other things on the distribution side--aggregators of DR who are putting gas generators on at just under the amount that's required to register as a generator…

Moderator: And on the economics of coal to gas?

Respondent 2: I think that if you look at the carbon tax regime, it's very punitive for coal. But I also think it's broader. It's a worldwide thing. Coal's receiving a lot of messages that it's not the fuel of the future.

Questioner: I totally agree. And my question is more about the fact that we're replacing coal with gas, and I'm wondering if that's the intentional policy decision, or that's where you're seeing replace it, rather than a combination of wind, solar and gas, for example.

Respondent 2: For TransAlta, they are going to take the coal plants and convert them to gas, so it's a way to extend their economic life.

Question 10: I think you should change the name of the panel from being about capacity markets being about asking why the reserve margin is so large. That seems to be the overriding theme of the panel. Which brings me to an observation.

Speaker 1, you talked about how operators seem to be risk averse, so we buy more capacity that we need. So, there's over procurement, which means the energy market's long, and there's now more "missing money" in the energy market, which means we need more from the capacity markets. And then you stopped. But I think you needed to continue and then say, if we do that, then all of a sudden, we get the rent-seeking behavior that we were talking about that people can't resist—"Oh my God, we need to put more money in the capacity market, so let's try to mess around with that," which means that we're going to get more capacity sticking around, *à la* what we see in PJM. There's a lot of capacity that probably should retire, but just kind of keeps hanging on. And then the energy market gets even longer. Then, all of a sudden, people are screaming about the capacity market, and it starts turning into a death spiral at this point.

So, the question is, why is the reserve margin so huge, going forward? But the big question I have is, given an energy-only construct with an operating reserve demand curve like we've seen in ERCOT, versus having a capacity market that we've seen in the eastern RTOs, where do you think investors are going to be more comfortable putting their money, if you believe in real options theories? Is it going to be the energy-only market, or is it going to be the capacity market?

And then, secondly, about financing, I'm going to push back a little bit and say that, yes, conditions here in Canada do matter in terms of financing, but money is fungible across sectors. It's fungible across borders. We're seeing investments being made in US markets from Korea, from Japan, Australia, or New Zealand retirement funds. We're seeing Canadian money come into the US markets, because they perceive returns to be higher in the US energy and capacity markets than they obviously do for some of the other potential investments.

Respondent 1: As an investor, you look at the jurisdiction you're investing in, and you assess political risk and those types of things. That does affect the financing for the projects. So, I don't disagree that money comes from many places, but that money still has many, many places, as you pointed out, that it can go. And so, investors are going to look at the sector and the jurisdiction when they do that, and my point is that it's different here than it is in other markets, and there are other financing tools available in other markets that aren't available here.

Respondent 2: I understand the questioner's point, and from a pure option standpoint, yes, the entities are going to like seeing a capacity market, just because of the guaranteed revenues, and that might make them more likely to invest. That doesn't necessarily make it the right answer. It just means that they're more likely to invest there. I think what we need to see in all of our markets, and that includes ERCOT, is some of these resources that are uneconomic for whatever reasons, they need to start retiring, and we need to start seeing those flow-through impacts on the energy market and the reserve markets and things like that. And when we start to see those things, then we'll get some clarity on all of these markets and where they're going to go.

But right now there is a renewable capacity rollout that is just unbelievably strong and that's just suppressing everything right now in terms of the revenue streams that people can get to. And so, we've got to be prepared to retire, we've got to be prepared to let some of these prices go high, and until we can get to that point, we can't answer the question about whether to have a capacity market or no capacity market. We've got to let some of that stuff play out, and let the prices play out, and then let the markets and the politics decide, do I want to be in a thousand dollar cap market, with capacity and side payments, or can I let the cap go, can I let these prices be where they need to be in the real time, let that roll into the day ahead, and let that roll into the forward markets, so people can hedge? And then, if they're making enough money, the capacity market, again, will become irrelevant, and you'll have equivalent investment decisions in the two market constructs.

Respondent 1: The only other thing I found very interesting is that when Alberta decided to go to a capacity market, we talked to a lot of the investors on the East Coast, and they told us all the problems with the capacity markets. And I went, "OK, OK, so then you'd rather not have one." And they were all like, "No! We must have a capacity market." So they obviously [LAUGHTER] find it valuable.

Question 11: Looking at what we see in the future, be it through market forces or because of public policy, particularly here in Canada, we're marching down this decarbonization path pretty quickly, and that's really through development of capital-intensive, near-zero-marginal-cost resources, and that's sort of what the grid of the future might be looking like, not tomorrow, but in 20, 30 plus years. How will we create a market that will stand the test of time through this change, or are we doing this again in 15 years?

Respondent 1: I would say we're doing it again in 15 years.

Respondent 2: Yes, I think capacity markets are a somewhat transitionary period, but I guess your question is about what the right market design is for a large penetration of low marginal cost assets that may be intermittent? I think that if you knew the answer to that question, you could have a lot of money, probably.

Respondent 3: Standing the test of time is a function of being able to roll through the cycles of the market, and we're in a low price cycle right now. It's not going to last forever, and then we'll go into a higher price cycle. I believe in energy-only markets. Earlier I said I wouldn't answer the question. I believe in energy only markets, but I don't believe there's a political will in all of the market operators and the market design committees that are run by market participants to get us to the point where the designs will allow an energy-only market to function properly.

Respondent 4: I think the energy-only market in ERCOT is sustainable, but nothing's permanent in this world, and it takes both legislators and regulators who will ride through the rough patches.

Session Three.
Carbon Emissions: Does Federal Exit Result In Heightened Pressure on States to Act?

The Trump Administration posture and actions on climate change signal where the Federal Government will be for the next 3 plus years on carbon issues, subject to judicial review. That posture, of course, does not make the issue go away, but it seems likely to move the forum for seeking action away from Washington and more toward state capitals. A number of governors have already signaled their willingness to accept more of a role. What does this mean for state regulators and for legislators as they look at the power sector and its carbon footprint? What measures might environmental groups be advocating? Will the carbon focus be primarily on the power sector itself, or will transport and industrial emitters of carbon be affected? Will the focus be on resources, such as renewables or energy efficiency, or on more macro policies such as carbon tax or cap and trade? How cost effective is it for emissions reductions for states to pursue their own individual carbon policies? Will a state-by-state approach motivate a backlash by large businesses to pressure the Trump Administration to ease its stance? What will state regulators do and how effective will it be?

Moderator.
This is the third and final session, and I wanted to pull two predominant threads through the cloth. This is just my perspective; it's not necessarily that of the participants here. The first thread has to do with the fact that the first session was about pricing carbon emissions and regional differences--the concepts of states as laboratories and the larger good of learning from different experiences, and now we know to add observing Alberta. At least I came away feeling that all is not bad, but it is not necessarily going to be easy. And I think we'll have time to talk about that as we finish the panel today. We contrasted regional approaches, with a strong focus on CAISO and the Western Energy Imbalance Market and the complexities of linkage effects and the challenge to least cost dispatch posed by the need to shuffle generator costs and emissions in real time. We can talk more about RGGI. I don't think that got full coverage yesterday, but there's an opportunity to talk about it today.

In the second thread, yesterday afternoon was about contrasting the energy-only and the capacity markets. There was much discussion, which I found interesting, around where the imperfections, or the economic inefficiencies from arbitrage opportunities, were actually leaving rate payer and of course investor money on the table. That's a risk of capacity markets. But, that said, I think a number of us learned, yesterday afternoon, a lot more about Alberta's initiative to move to a capacity market from the energy market they've got now. At least for me, it caused me to take a deep breath and think about how emissions targets, the investment climate, transmission solutions, generators, and provincial politics would all play in the same sandbox.

So join me in welcoming our panelists, and let's get started.

Speaker 1.
Good morning. To put today’s panel in perspective, we have Canada, which is a country which has a national policy regarding carbon emissions, struggling with what local governments are trying to do to embellish it with all sorts of other things, and with what that does to the electricity market, and then we have the United States, where we have no carbon policy at all, on a national basis, and all we can do is figure out ways around the fact that we lack a national policy. So the sort of global conclusion one draws is that people can't refrain from tinkering with whatever they have, whether it's to make up for deficiencies, or to do what they think complements a policy that's already in existence.

But the threshold question (and I'm addressing this as a not-yet-recovered state regulator who dealt with these issues in the context of sulfur dioxide before the passage of the Clean Air Act amendments of 1990) for a state regulator is, are we actually already regulating the emissions (or whatever the externality is--in this case we're talking about carbon)? If the state is already regulating the externality, do we really need to do anything more about it? This is relevant, obviously, when one looks at California, or you look at the RGGI states. You may argue that the carbon regulation regime is adequate or inadequate. But one of the things you want to look at it is whether we're already regulating and what the effect of any additional measures would be that as a state regulator, I would be asked to authorize or to require consumers to pay for.

So, the first question is the obvious one. Does the law in the state authorize the regulators to consider externalities? And is it in their general discretion? I'm not going to get into a lot of issues about statutory interpretation regarding regulation, but that's obviously the first question. What is the legal authority that I have as a regulator? And then the second question is, if it's not explicit in the law in the sense that it's not prohibited, do I have the discretion to do that?

Then the question is, assuming I have that discretion, how do I use it? Do I just simply say, “Well, anything that reduces carbon is good?” Or how do I balance off potential adverse consequences of something that might reduce carbon, but may have other consequences--environmental, social, or economic--that are problematic. How do I balance that? How do I actually do this weighing?

And then the other question, of course, is what I mentioned earlier, which is about the impact on existing regulations. If my state is regulating carbon, what do I have to add to that? For example, if what we have in my state is a price on carbon, and I start carving out niches for technology I happen to like, what does that do to the carbon market? What does that do to the overall efficiency in reducing carbon? So how do I actually weigh what measures I'm taking, and how do they fit into a larger context?

Now, let's assume, for example, that the state law doesn't say anything, or perhaps even precludes explicit consideration of environmental or other externalities. Does that end the question for the regulator? Well, the answer is, “Not necessarily.” Why? The place where I learned this was dealing with sulfur dioxide emissions when I was an Ohio regulator. It was clear then that at some point there was going to be regulation of SO2, and the question was, should I ignore that? (Actually, some of the utilities and most of the industrial customers were arguing that we shouldn't pay any attention to that at the time.) Or do I view building a new coal plant, for example, without consideration that there may well be regulation of SO2 if we do that, should I not be viewing considering this as a kind of insurance or a hedge against environmental risk? So I'm not really making a decision so much on the externality itself as much as I am trying to internalize some of the risks that are association with the potential of future environmental regulation.

For carbon, in the U.S., anyway, it's a little more difficult, because I think there's a broad consensus that something needs to be done about carbon, but it doesn't seem to be shared by the current administration or the Congress. So how I evaluate what the risk is and how much I'm willing to have customers pay to hedge it is a question. So the factors include the degree of the reality of the risks you're hedging against and then of course the prudence associated with hedging and the costs involved. Assuming you have a vertically integrated state, for example, and the utility does something erring on the side of excess caution against some future environmental risk, is that prudent? And how do you evaluate that? It becomes complicated.

And, of course, you also have the issue that if customers want a particular kind of product, the “green product,” we'll call it, you can do one of two things. In a retail choice state, customers can exercise their energy option and do whatever they want to do. If there is not retail choice, regulators, assuming the statute allows it, could still allow special contracts, so that customers can get exactly the sort of energy portfolio mix that they want. But that's leaving it up to the customer. That's not a question of imposing costs on customers who haven't really exercised that choice one way or the other.

If we're going to be looking at objectives, for example, emission objectives, say I'm a utility regulator. How do I know what those objectives are supposed to be? It's not the area of my statutory competence, and it's not necessarily an area in which I have subject matter expertise--maybe regulators are quite knowledgeable on it, but environmental regulators are going to have far more knowledge on it than the utility regulators. So the question is, how do you really asses what the objectives ought to be, and what we ought to be doing? Or do we just simply take this plunge and say something like, “We like these technologies and we will approve them even if they're above market cost because they have this beneficial effect?”

So establishing the objectives and kind of disciplining what the regulators do is a difficult set of choices and decisions to make. If you're doing it based on insurance or hedging against future environmental risk, how do you asses the reality of those risks? I already mentioned that. And then there's the reasonableness of the cost to be incurred. At what point are we not willing to pay for those kinds of things? What's in the realm of reason, and what's not? And then simply there’s the question of the prudence of the hedging expenditures. What's prudent and what isn't prudent?

Obviously, if you're in a retail choice state, this is a lot easier, because a lot of those decisions devolve to the customers, not to the regulators. But for utility regulators, these are not easy questions. Some regulators may just simply say, “We have no jurisdiction,” to this and others may want to pursue it, but there are all these fundamental questions.

And if you're going to do it, how do you establish regulatory review? Let's assume it's the utility that's undertaking these measures, do you do *ex-ante* or *ex-post* review? Do you actually set out the criteria? Do you, in effect, become the environmental regulator for the utility subject to your jurisdiction? Do you do it up front, or do you do some *ex-post* thing, or, for that matter, what happens if the utility, anybody subject to your jurisdiction, happens to have done certain things or not have done certain things to insure against the regulatory risk? Do you have some sort of *ex-post* consequences of having failed to hedge against an environmental risk? Now, obviously if the utility is not vertically integrated, that's a lot less of a problem, although they may have contractual obligations that raise the same sets of issues.

Then when it comes to, for example, how you treat rooftop solar or how you treat other distributed energy resources or how you treat either generating capacity owned by the utility or purchased by the utility, how do you evaluate that? Do you use some sort of cost-based way of evaluating these resources in the context of the relevant externality? Or is it market-based? This is really what the rooftop solar debate is about—do we simply say, “This reduces carbon, and therefore, we're not going to impose these kinds of market price disciplines?" How do you actually discipline the prices of what's paid for these things that aren't part of the internalized cost of the utility?

And then you have verification issues. If somebody comes and says, "Look, we don't produce carbon when we're generating energy," great. Does that mean, therefore, that they've reduced emissions? Well, no, not necessarily. There are a lot of other things one needs to know. And how do you actually verify? If you say, for example, that you as the regulator have some objective in regard to carbon reduction, what is it that disciplines that to make sure that a given resource in fact has the desired effect? We know from the German experience that simply putting on more renewables doesn't mean you're going to reduce carbon. There are all kinds of other variables that play into that market, whether it's the German experience with nuclear, or whether it has to do with what's actually being displaced. If you're doing this in New England, which uses almost no coal, and shortly will have no coal at all, it's a whole different question in terms of whether you're actually reducing emissions by using a certain resource than if you had that resource in the Ohio valley, which has a lot of coal plants. So there's a verification issue.

And then, how cost-effective is the investment? It's not just a question of whether you are actually reducing emissions. What are the alternatives? What are the most cost-effective ways of doing it, and how do we know that what we're approving—a pricing regime for distributed resources, or some other resource that we're allowing the utility to pass on costs from--how do we know that that actually is the most cost-effective way of achieving the result, or of hedging against future risk? So you have to do some sort of analysis or comparison, whether it's a cost-benefit study (and of course those are always subjective), or whether you do some sort of market test to actually find the most cost-effective way of addressing the externality you are concerned about--how do you measure and discipline this process?

Because any time you have this claim that, "You need to invest in this technology because this technology is going to have beneficial environmental effects," that ought not to be the end of the inquiry. In fact, you don't even know if the assertion is necessarily true. It may or may not be correct. And then, how do you drive down the cost of actually reducing that externality? Does the approach you are considering have some sort of market mechanism, like an auction? Do you have a remuneration based on technology cost-effectiveness? Those are just some examples of ways you might try to discipline the prices that are paid.

These are all tough questions for regulators, because this is outside the normal way that regulators do business, which is to ask, what are our energy needs, how do we meet them the most cost-effective way, how do we discipline prices? We know how to discipline prices in general--either through markets or through cost-based regulation, but now we're in sort of never-neverland and we need to think about how you would have to impose certain disciplines.

So what are the conclusions? One is that the powers of the regulator are uncertain, even if the statutes are clear, because basically there is an economic argument for looking at externalities, which is the hedging argument. So, even in the face of some statutes that appear otherwise clear, regulatory powers are really uncertain. So that's one question. We have to find a way to address that if we're going to be engaged in this sort of consideration of externalities, and certainly there's a whole philosophical argument that you shouldn't do that, but if you're going to do it, you need to do it in a disciplined way. It has to be in a way such that prices are actually disciplined. Cost-effectiveness trumps technology (no pun intended. "Trumping" is taking on an entirely new meaning.)

So, the question is, what are we going to emphasize? My view, as a former regulator, and just an observer of the scene is that cost-effectiveness is going to trump technology. I may love a technology, but if it's not cost-effective in achieving the results I want, why wouldn't I go with an alternative technology that is more cost-effective?

And then, there needs to be obvious documentation and quantification of the emission reductions. This would apply to any sort of externality that you want to look at. In fact, when you're defining externalities, are emission reductions the only thing? As I've argued this many times in regard to rooftop solar, rooftop solar may or may not reduce emissions. That's a very time and location-specific question. But if it does, we also know that net metering, which is often used to price rooftop solar, is socially regressive. That's another externality that one cannot get away from. So how do we actually figure how to balance the externalities so that it's not arbitrary? If you're going to look at externalities, and you only look one dimensionally in terms of one externality, I think that's a problem, and it's an inadequate kind of review.

And then the final question, of course, is the appropriate risk allocation. What ought to be the risks borne by the utilities or borne by generators outside the market or by vendors of technology, and what ought to be risk that gets passed on to consumers? And those are also quite difficult questions that I think have to be evaluated.

But the thing that concerns me, and this is sort of the final message from what I'm saying, is that the process has to be highly disciplined if we're going to get into this externality.

And one final note that I mentioned in the beginning, but that I want to go back to: if there is already a regime to regulate the externality concern, what is the impact of a regulator then imposing some additional tinkering? And I think one could argue very powerfully that where we have, for example, RGGI, or in California where you have a carbon market, and then you top it with all sorts of preferences for storage, for rooftop solar and for all kinds of other favorite technology, what have you done to the basic carbon market you've tried to create? And what have you done to the overall cost effectiveness of reducing emissions? Thank you.

Question: Two states have now adopted a social cost of carbon. Minnesota and Colorado have various forms of that. And that's what's used in evaluating the various costs of resources and in determining what least cost is. Do you think that those kinds of tests are valid? Are they able to get to a level of precision that you'd be comfortable with?

Speaker 1: Well obviously I can't speak to those two particular studies because I haven't seen them, but in a generic sort of way, yes, that's one of the factors. It's not the only one though. Evaluating what the social cost of carbon is is obviously an important consideration, although you're going to have a hard time finding broad consensus on what that is. But that's certainly one consideration.

But then the next question you need to get to is how these various technologies fit into a cost-effective way of trying to bring down the social cost of carbon. And how cost-effective is it actually going to be? So you need to go beyond just saying, "We know that carbon is going to have a social cost. Here's what we think it is, and we're going to evaluate resources based on that." The question is, then, is there any technology that can get this sort of preferential treatment in terms of rate treatment or pricing treatment? So I think it's a much broader inquiry. I think the social cost of carbon is certainly an important place to start, but it is not the end of the inquiry.

Speaker 2.
I'd like to give a utility's perspective. It's our customers, at the end of the day, that need to pay for all this clean energy and rejiggering of the markets. We've seen a lot of presentations yesterday, some a bit more technical and specialized than others.

I'll give a high level overview. I think the difference between a specialist and a generalist is that a generalist knows less and less about more and more until he knows nothing about everything. Well, a specialist knows more and more about less and less until he knows everything about nothing. So I'll try to keep it balanced as I go through this.

So the question posed was whether federal exit results in heightened pressure on states to act. You could see from some of these quotes from governors in New York, Massachusetts, and Rhone Island, that we were already well ahead of the game in New England, and the fact that this administration may be backing away from the Paris climate accord as well as putting in some new and different proposals (like Secretary Perry's proposal)… I won't go through every one of these quotations, but there's a level of bias against the administration.

I don't think any actions being taken by the federal administration are slowing down or hampering the states in New England, at least, in any way at all. The states in New England and New York, they've had 80 percent CO2 reduction by 2050 goals across the Northeast since well before the Trump administration has been in place.

In Massachusetts, we've got mid-term goals of reducing CO2 reductions from 1990 base levels by 25 percent by 2020, and by 80 percent by 2050. In Rhode Island, it's 45 percent by 2035 and 80 percent by 2050. In New York, it's 40 percent by 2030 and 80 by 2050. And New York has got kind of an additional constraint, in that it wants 50 percent of its electricity to be generated by renewables by 2030 as well.

So the states are already committed to improving environmental performance. Our operations are all in progressive jurisdictions. There are robust renewable portfolio standards and support of electric vehicles across the states. I don't think there's anything that's happening at the federal level that would slow anything down in New England. In fact, New England will keep marching forward despite anything that happens.

So here's just a selection of some of the decarburization policies and goals for each of the states in New England and New York. New York, Massachusetts and Rhode Island are all part of RGGI. We see some reductions in emissions. Some might say that the levels set by RGGI aren't necessarily driving or may not have driven those reductions, and that sometimes it may be a more of an effect of the economy and the shale gas revolution that has helped increase the use of gas versus coal and oil and brought down emissions rather than the effect of RGGI itself.

In New York, we've got renewable energy standards; we've got the ZECs, the Zero Emission Credit program that's helping to support nuclear plants already. That looks like it may cost our customers $12 to $14 billion over the next five to seven years in support of at least the upstate nuclear plants that we're trying to keep open. And then the Governor's got offshore wind commitments, and this isn't legislated or regulated, but it's a goal that the governor's put out there to try to achieve 2.4 gigawatts of offshore wind. Maybe that's a challenge.

The legislation in Massachusetts was looking for 1.6 gigawatts of offshore wind. So it seems one state may be trying to one-up the other at this point. And then, of course, we've got the Reforming the Energy Vision (REV) initative in New York, which is more at the distribution level, trying to set up a distribution pricing system for DER and storage. Hopefully that can work within the wholesale energy markets and kind of drive towards the same goals to reduce emissions over time.

In Massachusetts we've got renewable energy portfolio standards for class one and class two renewables (class two is waste-to-energy). We've got alternative energy portfolio standards; we've got the new Clean Energy Standard, which is incremental to the existing RPS. We've got the offshore wind legislated mandate for the utilities to secure 1.6 gigawatts of offshore wind by 2027, I believe under legislation 83C. Under 83D, we are actually in the middle of an RFP right now, looking for 9.5 terawatt hours of clean energy. We've received over roughly 5,000 megawatts of projects in the 83D, 9.5 terawatt hours RFP, and we're in the evaluation stage, trying to determine what the best projects or portfolio of projects are, with the objective being to select something by January 2018 for that stage, which is pretty aggressive, given the number of bids that have been put in.

And then Rhode Island itself has got renewable energy standards and renewable energy growth programs, and Governor Raimondo is looking towards a goal of trying to achieve 1,000 megawatts of incremental clean energy and 20,000 clean energy jobs by 2020, which is extremely aggressive for a state that size.

So in New York, in August of 2017, the NYISO and the Department of Public Service (DPS) issued a report from the Brattle Group on pricing carbon into the NYISO's wholesale energy market to support New York's decarburization goals. That report was almost a year in the making. It's looking for a development of a proposal for decarbonization and then carried forward by a joint team comprised of the New York ISO, the DPS and NYSERDA. Other approaches will be considered as informational by the joint team. There isn't much time to come up with a joint proposal that's different than the carbon proposal that's out there, given the fact that they're looking to produce a proposal subject to PSC and NYISO's governance process by February of 2018.

So there are different processes that have been going on in New York and New England. New York is targeting DSM. In New England in 2016, NEPOOL (the New England Power Pool), with participation by ISO New England and the New England states, established IMAPP (the Integrating Markets and Public Policy initiative) to identify and explore potential changes to the region's markets that could be implemented to advance the public policy objectives across New England, looking for ways to both “accommodate” as well as to “achieve” these objectives. And there are some who say that they don't want the federal government to “accommodate” the states. They want the states and the federal government to be able to harmonize on solutions. So it's a little nuanced, but people get really concerned about the language.

ISO New England has proposed a short/medium “accommodate” approach, with CASPR (Competitive Auctions with Sponsored Policy Resources) that accommodates policy resources into the forward capacity market over a period of time. I think that's really just a short-term solution, where generators that are looking to retire would bid into the market, and if they decided to retire, they could pass their capacity revenues over to support clean energy projects that otherwise wouldn't have been able to clear the market, so that kind of preserves competitively based capacity pricing for other resources.

And then we've got the 200 megawatt a year exemption from FERC for clean energy. I don't know that it's actually been used yet, and I think CASPR and some of the other proposals that NYISO has got may kind of usurp that 200 megawatt a year goal, but it's still out there. And then National Grid continues to work with the Brattle Group and others on a Dynamic Forward Clean Energy Market with a potential to achieve long-term solutions available for states to use in procuring new and existing clean energy resources is to satisfy state goals. The idea is to try to dynamically value and reward and incentivize production of clean energy, at times and locations providing greatest emission reductions for the system. That sounds good, but given the location of large-scale renewables, at least in New England, this may be a little bit harder to achieve unless storage becomes really cost-effective over time.

So, from the utility perspective, the guiding principle of monopoly regulation has always been to provide safe and reliable service at least cost in the utility’s franchise area in exchange for recovery of prudently incurred costs and a fair return on investments. And today's regulatory paradigm seems to be shifting a bit, as related to federal and state clean air policies and targets. When we talk about picking winners and losers, like coal and nuclear over other types of fuel, New England seems to be picking winners and losers when it comes to clean energy as well. And if you've got an RFP that's looking for a certain amount of terawatt hours from hydropower, or a certain amount of gigawatts from offshore wind, you've already kind of prejudiced the clean energy markets, whether or not a carbon price would have chosen offshore wind as the most cost-effective solution to satisfy the clean energy goals. To me it's pretty questionable.

And it's our customers that need to pay, so there are a number of questions that are raised. What are the costs of these initiatives? What delivers the most benefits to customers? Is meeting the state's goals through a fragmented approach the most efficient, effective way to address decarbonization? Is it possible, over time, to simplify the array of policies? Can we come up with a wholesale market solution that is not necessarily an overlay to RGGI or other policies, but is in lieu of other policies, so we just have one program going forward that kind of resolves all these issues once and for all? And how should these policies be judged? Who should be making decisions about them, when it comes to state and federal jurisdiction? There’s a lot of debate going on about whether or not FERC has got the right to set carbon pricing, or whether the states have got the right to set it at whatever levels they want in order to be able to achieve their goals. And then, obviously, what are the effects of DOE’s submittal to FERC regarding baseload generation, and is it in conflict with ongoing state clean air agenda? So it seems, once that was published in the federal register, that the focus is really on RTO markets that had both energy and capacity markets, so that really limits it to PJM, ISO New England. And if we're looking to support coal, and coal is a dirty fuel relative to everything else, isn't that kind of divergent, or opposite of, what the states are actually trying to achieve in decarbonizing?

So, a lot of these programs are in conflict with each other. To achieve the states’ goals, unprecedented amounts of zero carbon generation will have to be developed by 2050. We believe that large-scale generation needs to be a central pillar of any pathway to reach states' greenhouse reduction goals. Relative to other zero emitting resources, large scale renewables possess valuable characteristics that provide value for our customers. So they offer significant cost advantages and are increasingly cost competitive with conventional generation and more cost effective than DERs. And when we combine DERs with storage, that's a pretty expensive solution compared to large-scale generation. In addition, large-scale renewables allow for rapid expansion of generation capacity. Large-scale renewables are also easier for RTOs manage for reliability than a series of distributed energy resources that may or may not be aggregated and may or may not be dispatched in the RTO markets.

The problem is that there are a lot of transmission systems in New York and New England that have to be expanded to allow for an integrating large-scale renewables (LSRs). So we believe that a balanced approach, involving a mix of DERs, economic storage, LSRs, and requisite transmission to deliver clean energy to load is required. The most promising locations for clean and renewable development require new transmission infrastructure. In New York, upstate wind and hydropower will require delivery to end-use customers in southern parts of the state. In New England, Canadian hydropower, and wind up in Maine and northern New Hampshire andVermont is all far from end users that are in southern New England load pockets. For offshore wind, there's no existing offshore electric network. So new transmission will have to be built and planned.

We're a proponent of maybe taking a look at all the offshore wind as we develop the RFP for Massachusetts, 1.6 gigawatt hours. We're looking to do it in minimum 400 megawatt hour chunks. So is it cheaper for each 400 megawatt chunk to be able to just come right to a delivery point, or should we develop an offshore electric network that kind of aggregates that all and brings it in?

For procuring large-scale renewables, we support a market-based approach. We're in the position that we really oppose mandated long-term PPAs for our electric distribution customers that seek to shift a lot of risk from developers to utility customers and shareholders. I like to refer to it as "virtual ownership," with all the risks, but none of the benefits, of actually owning the generator—so, no return on the investment, but we pay for it. They're relying on the credit of the utility to shift the risk from the developer to the customer and to our shareholders, and to us, that seems a bit unfair. We believe an alternative to that would be for the utility itself to own large-scale renewables. We can show that, over time, if we enter into our PPA for ten or 20 years, at the end of that contract, although the REC value is now no longer in the hands of the customers, the developer can then sell that into the system, into whatever markets that are out there, and then the utility's got to replace that, so if the utility could just own and operate it in the first place, using its strong credit and its lower cost of capital, and own those RECs for the life of the asset, we think that's a better option than being mandated to enter into contracts.

We also have internal goals that are looking to achieve the same targets that the states have. As far as electric vehicles, we plan on converting a portion of our fleet to electric vehicles. If we're expecting to meet the goals of the states that will not only require a conversion of electric generators but also electrification of transport and commercial and residential heat, then naturally we ought to be doing the same thing, converting our own fleet to electrification, over time.

As this chart shows, the states can't achieve their goals on the back of electric generation alone. Electric power in New York and Massachusetts produces less than 25 percent of the emissions across the region, so even if you went to100 percent clean generation, you're still nowhere near achieving the goals that the states ultimately want to get to. So in order to do that, we've got to focus on transport and residential commercial heating, which may actually increase the load of the LSEs, and just exacerbate how much generation needs to get built to be able to supply that increased load.

The conclusions are that New York and New England are unlikely to be diverted by the federal government's current posture. State reps have made clear their ongoing commitment to decarbonization and various initiatives are in place to achieve it. ISO New York and ISO New England are both looking at ways to integrate public policy resources into the wholesale markets, which, again, is our preference. We're fully supportive of these goals, but we want to make sure that it gets done in the most cost-effective way. And it seems to me that the Department of Energy's proposed NOPR raised a raft of additional questions and has the industry in a little bit of an upheaval, as one might expect.

Question: When you were referring utility-based renewables (versus market-based), that's the full cost of service payment, like a regulated model?

Speaker 2: Right. As I said, we're fairly opposed to being mandated to enter into PPAs. New York has got a model where NYSERDA actually does the procurement of long-term energy contracts. As New York was going through the Clean Energy Standard, there was a lot of debate on what was the best way to do it. Utilities pushed back pretty hard that we were really opposed to mandated PPAs. So, ultimately, it fell back to NYSERDA to be able to continue to enter long-term contracts with developers. But one of the alternative is, if that didn't work, you can do an RFP to a developer to develop a resource, and then, once the unit is developed and built, you could flip it to the utility, who can then operate it long-term, with the benefits of its lower cost of capital, and, again retention of the RECs at the end of the life cycle.

Question: Quick question on your electric vehicle proposal. So it looks like you have a major proposal in Massachusetts, but not in the other states in which you operate. So I'm just wondering what's driving the proposal in Massachusetts versus the other states, or whether those will come later.

Speaker 2: It's just a question of timing. We're in the middle of a rate case at Niagara Mohawk, it's an electric distribution utility in New York, and we had proposed electric vehicles within the context of that rate case, as well as other things associate with REV, like automatic meters to help meet the state's goals for REV. So it's just a question of timing as we go through each of our rate cases.

Question: Yes. You said a couple of times that nothing that the federal government is doing is hampering states' efforts. And I wondered if you meant their resolve, or the efficacy of those efforts. Because it seems like, if the states are trying to impose costs on high-carbon-intensity resources, and the federal government is saying, "You get to pass those costs through," that would undermine any of those efforts.

Speaker 2: I guess what I meant was that the states in New York and New England had been well along the path before the Trump administration came in, and obviously anything that goes over the carbon pricing in the wholesale markets has to get approved by FERC, ultimately. ZECs and RECs have been upheld in New York as being support systems for utilities, but not necessarily to the extent that they are impacting the wholesale energy prices. I think, as we go on, the level of those prices and how much it impacts all the generators may get to a point that FERC may look to slow things down or stop things. So, it's not to say that New York has complete jurisdiction, or the other states have complete jurisdiction to do completely what they want. But they don't seem to be hampered by the federal government--at least, they seem to be well ahead of even the Clean Power Plan goals. Each one of the states had their own goals that were well in excess of what the Clean Power Plan would have placed on them.

Speaker 3.
I guess I'll just start with that the context for this pane,l and why this is such a timely conversation to have. Obviously, the difference between this administration and the previous one, it goes without saying, is a stark one. Before the Obama administration moved as it did to act on carbon in the power sector, the status quo had been more like federal inaction on carbon and climate change. And now, post-Obama, we see a federal government that's moving aggressively in the opposite direction. Not just doing nothing, but trying to actively prop up the most emitting resources. So that's a stark difference. And it's problematic for utilities, but not just for utilities, for other actors that are making large-scale and long-term infrastructure investments in power generation, transmission, and other investments, because a ping pong table is not an easy place to make a bet, if you're trying to bet which side of the table the ball's going to be on. And I think we could all do a fair bit better. I

'll talk a little about the specific role of states, and how we're planning to move forward, and also just a bit about that sort of red state/blue state dynamic, a little bit about the context of prices, and electrification, and then I'll wrap it up, hopefully without droning on for too long.

So, as Speaker 2 said, state action in the context of carbon certainly pre-existed the Clean Power Plan. There's some element of reaction to this move to rescind the Clean Power Plan that I think will encourage states to be bolder than they otherwise would have been. We've seen a number of governors step up with more commitments. I think the level of involvement in international forums will increase. You'll see more ambition and more action in that regard. But it's not a new phenomenon.

Speaker 1, I believe, was talking about PUC regulation of carbon primarily from an economic regulator perspective. But we also see states directly going after carbon from a statutory perspective. Obviously, some of the RGGI states have passed statutes to accompany it. But there are also states that have used what they view as their pre-existing state Clean Air Act authority, along the lines of the Clean Power Plan federally, so New York, Washington, Virginia, and New Mexico actually had a state Clean Air Act-based rule (in New Mexico, that rule was rolled back under the current governor). But I can imagine other states doing that as well, if they're not able to pass legislation.

I think the fundamental concept that states have the authority to go after what is obviously a dangerous pollutant shouldn't be a surprising one, and I wouldn't be surprised if more states move in that direction. But of course you'll also see a whole range of what we call “complementary policies” and what others might call “unfortunate subsidies” or “mandates.” But these include tax incentives, renewable portfolio standards, and energy efficiency (either mandates or targets or goals). Obviously, there is also direct carbon regulation--carbon taxes, emissions performance standards--we haven't talked about that so much here, but I think it's been really impactful in the West, both in stopping the rise of coal a decade or so ago, but also in precipitating the decline of coal across the West. Those policies…I think we'll see more of them. I use the example of Nevada, where the legislature in 2017 passed 11 clean energy bills, nine of which were signed by the republican governor. So I'm hopeful that, in the coming years, we'll see more states taking up that kind of action.

And of course, there'll be some back and forth just like there has been on the federal level. I mentioned that New Mexico passed a rule on a kind of cap on carbon under the previous governor, Governor Richardson, and that the current governor rolled that back. We'll see some of that across the states as well. We expect a couple of the elections around the Northeast might mean more members of the RGGI collaborative. Hopefully there won't be some pull-back based on some of those elections as well.

Again, this gets to sort of the red state/blue state ping pong table effect that makes investment more difficult. I will say that even in the context of that red state/blue state dynamic, there are some policies that remain close to universally popular. Investments by utilities, for example, and energy efficiency, continue to grow around the country in every sort of jurisdiction. In the West, states like Arizona and Utah and Idaho all do a fair bit on energy efficiency, pretty cost effectively for their customers, and also, I'd say, cost effective from a carbon perspective.

That said, I think 2018 could turn out to be something of a swing year for states. Obviously, it's an uphill battle for the Democrats to take back either chamber, and even to hold their current slim minority in the Senate. But they are more favorably situated with regard to State Houses, and their chances of winning back State Houses, I'd, say, are somewhat higher. And therefore, the chance of more state action after 2018, around the country, I think, is very likely.

I'd say that's only amplified by the role of cities. Now, cities, for the most part, don't have a whole lot of regulatory authority over utilities. There are obviously some municipal utilities, including some important ones like the Los Angeles Department of Water and Power (with the biggest union in the country) and a few others. But cities do have a whole lot of influence over their utilities; utilities' largest loads tend to be in cities. Obviously, cities have a huge amount of economic activity, and we're increasingly seeing cities adopt policies around renewable energy--100 percent renewable energy goals, carbon reduction goals—and we're increasingly seeing cities using those targets to, if nothing else, twist the arm of their local utility to move in that direction as well. I think we'll only see more of that.

There are also some more direct, and I'd say effective, policies by cities with regard to energy efficiency. Building codes, for example, or requirements that make more transparent the energy use of large buildings for their customers. I think we'll see more of that activity as well.

The next theme I just want to touch on here is that of price changes, which are driving a lot of this. You wouldn't know it from the Department of Energy recently, but obviously a huge amount of the trend that we've seen away from carbon in the power sector is driven by price. And I really regret our rules here, because I would love to quote one of earlier speakers talking about retirements not being a bad thing. I agree with that, and we've seen a lot of retirements of uneconomic units around the country. I think we'll see more and more of that. A rough analysis that I helped take part in earlier this year showed something like 200 gigawatts of coal around the country that has operating costs higher than that of new wind contracts in the region that it operates in. So, that's not an all-in comparison--obviously, there are balancing and other reliability considerations, but if your energy price is higher than the energy price of a competitor, you're going to be under some pressure. And with wind prices below two cents and solar prices below three cents in big chunks of the country, we think that trend will continue.

And the question is, how much will market actors be shielded from the price effects? Resource planning requirements in many states are forward-looking, not backwards-looking, so existing coal plants aren't necessarily facing that market pressure. Co-ops and munis that own a fair amount of coal are not as directly regulated in that regard. So there are a number of ways that those plants can hang on, but I really do think it's a question of them hanging on against economics.

There are other obviously non-economic, or not directly economic, barriers to significant and rapid transformation of the sector. Siting of transmission, siting of wind by itself, is difficult. There's a question of the depreciation schedules of many of these plants. Customers may be paying them off for decades to come, even if their useful life ends much sooner, given their economics. And of course there are the political questions. I think there's no doubt that the Trump administration gained a lot of clout by their promises to protect the very small number of remaining coal workers. These are small communities, but they're politically important in the West as well as in the East. And so that remains a really tricky issue, and I think it's unfortunate that the conversation remains about trying to pretend we're going to hold on to the coal sector, rather than being about meaningful economic transition and opportunities for those communities.

If I sound Pollyannaish about the economics of clean energy moving us away from dirtier sources, I do note, obviously that some part of that price that I mentioned is the result of the Production Tax Credit and the Investment Tax Credit, and those are phasing out. That deal, as I saw it, was made with the understanding that carbon pricing was coming, and that the Clean Power Plan would be rolling in as the Production Tax Credit was rolling out. That deal is looking less and less fair, and so I don't know where that'll head, or how this Congress will treat those issues, but my hope is that the cost reductions that we've seen across wind and solar will remain, to some extent, even as those tax credits phase out.

Another theme here is that of electrification, that Speaker 2 mentioned. We're definitely seeing state policies move in this direction in a couple of different ways. Obviously, there are a small number of states that have adopted California’s Zero Emission Vehicle standards under their Clean Air Act waiver. A number more states are looking at possibilities for investment in charging infrastructure. Obviously, concern about charging is one of the potential biggest barriers to consumer adoption of electric vehicles. So we're seeing a number of states, actually red and blue states, adopt authorization, at least, if not mandates, that utilities provide applications for investment in charging infrastructure from California to Utah and others. In other cases, it's being done separately, through rate cases for example. But we think that there's a huge opportunity for the electric sector here. In a sector that's mostly flatlining in terms of demand, this is an opportunity to essentially double load in the next 20 to 30 years. And in addition to just doubling load (or roughly doubling load), it will provide both opportunities and challenges that I'd say are comparable to the opportunities and challenges of intermittent resources and may provide some solution to the challenges of intermittent resources, because you have potentially millions of distributed storage sites plugged in. But, of course, depending on how those things are charged, cars are used about five percent of the time, for the most part. If they're plugged in all of the rest of that time, you can have a pretty useful resource. On the other hand, if they're not plugged in, because of the way that we invest in charging infrastructure, and instead they use this more gas-station-like model and plug in and rapidly charge a couple of times a week, then you can imagine a really peaky new source of demand that could be pretty difficult to integrate, especially in the context of an intermittent resource dominated grid. So I think there are certainly challenges to confront there, and multiple sorts of opportunities as well. But we see that states taking the lead on that as well.

I'll wrap up now with just a couple of comments. I think we will make progress on climate in the next three and a third years left of this Trump administration. I think it's unfortunate that it will be slower, even with some significant portion of the states and cities moving even I'd say more ambitiously than they likely would have under a Democratic administration. My hope is that that movement will be sufficient to precipitate the technological changes, continue the cost curves going down, and bring about the technological changes in integration and in storage that we need to move to a zero-carbon grid, and hopefully also, in this next decade, as we're already seeing devastating impacts of climate change, avoid going off a cliff of the most dangerous levels of carbon pollution and temperature change.

The last thing I'd say is that an objective of NRDC is to use this time, and the locally-driven action, whether it's city action or state action, to really build our movement and build the consensus for the need and opportunities for action around climate change. And so, hopefully, in 3.5 years we'll have a president that's willing to act on these issues, and a Congress that's willing to cooperate, based on that stronger movement that we're developing now. Thanks.

Speaker 4.
I think of a few themes what the states are doing and what their reactions are to federal policies. First of all, as you've heard already this morning, low gas prices will continue to drive a lot of the decision making and a lot of actions that states are taking, as will increasingly lower costs for renewable energy, and technology increases and customer choices and things like that. Those kinds of trends aren't going to go away; they're just going to be exacerbated in the next few years. So, those are all things that are going to have to be taken into account.

There are a lot of other measures that are being taken, not necessarily for carbon reduction purposes, but that will have that impact. You can make an argument about things like ZECs that, at least in Illinois, they have a lot more to do with jobs and tax base than they ever did with carbon reduction, but, nonetheless, you're going to keep nuclear plants operating as a result of that. So there are a lot of those actions that are going on.

And I also think that states have been here before, and they're used to taking action, and they're used to trying to drive some of these issues. If you look back into the George W. Bush years, you had a lot of state action that was happening, and a lot of states trying to coordinate with other states. Things like RGGI got started. And so it may be that they've done it before, or as one state official put it to me, “We've always had that pressure.” It's always been on states to do things, because, as we have talked about, there really hasn't been a federal energy policy in the country.

In terms of federal policies, looking at the Paris Agreement, obviously, the U.S. is still going, but we don't know what the message is going to be from the representatives of the federal government who are there. The Clean Power Plan is still in the courts. It's interesting, from a lawyer’s standpoint, to watch the D.C. Circuit and how they're going to relate to the new rule that comes up and all of the other challenges that are there.

The other part of this is that you're going to start to see, I think, some suits against individual utilities that will start to be brought for non-action, as well as people trying to sue the EPA to get them to do some things. The process for the repeal of the Clean Power Plan is out there now. It’s interesting we don't have a new rule proposed yet. We probably will, and probably, just for those of you who are longing to talk about the Clean Power Plan, it will be along the lines of building block one form the old Clean Power Plan.

And now we've got the new DOE FERC potential directive. It’s pretty tough right now to see what the fall out from that is going to be, or what that's actually going to look like. But there certainly has been a lot of reaction to it. I think it would be charitable to say it's been mixed. I was actually in a room of state air and energy regulators when that got announced, and people's phones started blowing up, and so we spent the next hour trying to figure out what they were meaning to do by that and how the actual proposal that DOE put forth to FERC could actually work. So we'll see a lot of that play out.

And I think part of the issue for states is that they're getting mixed messages from the federal government, as well. Secretary Pruitt was out the other day saying, “We don’t want any top-down management of the energy system and we don't want to pick winners.” At the same time, Secretary Perry's directing FERC to pick winners and have a top-down energy management system. So if you're a state trying to react to that, whether you like those policies or not, it's a little bit difficult, so I think what a lot of states will do is try to forge their own way, as you've already heard has happened before.

So, state reactions, as expected, to Paris, the Clean Power Plan repeal, and the recent NOPR…state reactions vary. A lot of people looked at it and said, “Well, this at least gives us some breathing room. If the Clean Power Plan isn't there anymore, if we don't have Paris kind of hanging over our heads in terms of a national at least direction that we need to go. Maybe the coal plants that might’ve shut down can run a little bit longer. We don't have to submit our plans.” There was some of that out there, but actually, even in a lot of red states, people think a carbon plan is going to come at some point and they don’t want to get into a position where they start taking action now that's going to end up with the ping pong table effect, so they’re going to have to reverse direction in just a few years. And as one commissioner put it to me, “We're going to be in a lot worse shape if we do that, because we'll have made decisions that we not only have to undo fairly quickly, but we will probably have to go even deeper than we might have before.”

I mentioned how there are a number of state actions that are not called climate actions, but still have an impact. The state actions I'm going to talk about (and the other policies I’m discussing) are are not meant to be exhaustive lists by any measure, but the examples are more just to give you a flavor of some of the things that are out there. RGGI's been talked about a little bit, but, as most of you know, they just recently did further ratcheting down of the cap in RGGI, and you can see that they're expecting some fairly large greenhouse gas reductions to happen as a result of that. RGGI's interesting to me because it's a bipartisan. You've got governors of both parties there, and you're going to see a continual downward ratcheting of the cap. The Emissions Containment Reserve it's a new piece of that, which is an offshoot of the fact that a lot of the feeling is that the prices have been too low. And, as somebody mentioned earlier, that might not be driving enough climate reductions in RGGI. And so the Emissions Containment Reserve is meant to address that.

So then you've also got Pennsylvania and Virginia that have talked at various times about wanting to join RGGI. That seems to have cooled a little bit although they are still talking about ways that they can reduce carbon there. And Virginia, which I'll get to in a minute, is doing something fairly ambitious with respect to climate policy.

You've got the U.S. Climate Alliance, which is now 15 states. And as they're talking about it, this is partially to send a message to other countries to stay in Paris. We expect to hear more from this in November, as was mentioned. It keeps the issue going and it keeps it out in the public pretty well. We'll see what the impact of that actually is, or whether it's more just a group of states who are doing things anyway, rather than a concerted action like a RGGI.

The other part of this is that administrations change in state government, too. There was a time when RGGI had just gotten started. There was a group of us in the Midwest that was doing an economy-wide, not just power sector, but economy-wide greenhouse gas reduction plan. They were doing it in the West, and we were talking about how we could link the three groups to have a little more than half the population of the country in a linked carbon market. And then in the Midwest, a whole bunch of new governors got elected, and so the three regions group became two regions and a couple of guys, because that's all we had left in the Midwest. So, just as a word of caution that administrations can change, and that has a dramatic effect.

We heard about the PUC just updating the social cost of carbon in Minnesota. You see a lot of other states that are taking or have taken action. These actions are not all in the last few weeks, but some of them are fairly recent. The one I'll talk about is Virginia, because they've actually got a greenhouse gas reduction rule that's being developed by their air regulators that's going to be proposed in November. This is through executive orders from Governor McCullough. And they want a trading-ready program that they want to be able to link to RGGI, so they're in conversation with RGGI now about how that's going to occur. They're talking about the Emissions Containment Reserve as well, but Virginia also has a governor's race that's coming up here very shortly this year. So the question becomes, what will happen as a result of that?

But there are interesting things happening, like in New Jersey, both candidates for governor have said they support re-entering RGGI. We've seen, from the Pennsylvania example that doesn't always mean that, but at least it's interesting.

The Midcontinent Power Sector Collaborative developing a decarburization roadmap that’s broader than just the power sector. They're also looking at transportation and EVs now. And this is a group of a lot of utilities, munis, co-ops, environmental NGOs, state officials, and others who have been working on Clean Power Plan issues for a long time, and when the election happened, they decided they wanted to pivot, and start working on a decarburization road map, which is pretty interesting for a stakeholder group that's as diverse as that one is.

I mentioned the regional groups that are out there. There's a ton of activity, as we already heard, from the C40 cities. All the work going on in terms of building codes in New York…Chicago's doing a lot with buildings as well. There's an urban sustainability director's network that consists of 135 communities. There are 375 “climate mayors.” A lot of that happened as a result of Paris, where a lot of mayors started working on this issue in earnest, if they hadn't been before.

There’s a lot of effort with the electric vehicles. We've already heard a lot about that, but the interesting thing there is people talking about some corridors to enable better charging throughout different parts of the country.

And there are also utility 2.0 or utility business model efforts. Power Forward is in Ohio. NextGrid is an Illinois effort. Rhode Island--we're working with them right now. They are going to actually put out some principles here fairly soon this month to coordinate with Governor Raimondo's efforts to do more renewable energy and more clean energy jobs. And then there is REV, Minnesota's E-21, and probably a lot more, and, as we said, that can have a really big impact on what's happening in terms of climate policy as well.

Then a number of states are touting clean energy job growth. I mention Kansas just because it’s a red state, and eight of the ten top solar states in terms of installation last year were states that also supported President Trump in the election. So it's not just a blue state issue that's going on.

Lots of utilities who are making a lot of commitments to renewables, and the interesting thing is kind of that last bullet point about long-term planning horizons. You'll see in articles, or you'll hear folks interviewed, or we've had them in conferences, and people talk about the long-term planning horizons and the energy industry and it goes back to that idea that, “We don't want to have to keep shifting policies back and forth depending on who's in the White House.” And people have said we're going to continue with our efforts. In fact, just last week, DTE in Michigan recommitted to their 80 percent greenhouse gas reduction goals by 2050. They just said, “We're not going to change our plans. The things that are happening in D.C. are not going to change that.”

And then you can talk about customers, large customers and these are just a few examples. Some people are actually arranging to either purchase the wind farms or purchase wind or RECs. And those are some major companies, and this ends up being an economic decision for a lot of states, too, and goes back to that point that state actions are not always done for climate reasons. There's a very red state that's really working hard to try to add a lot more wind energy. The governor's a climate denier, but they're trying to do that, because they want to be able to attract these companies that are talking about wanting 100 percent clean energy. So they see it as an economic development driver for their individual states. And that's not something that's going to change based on who's in the White House or what Congress thinks about any of these issues.

So, again, (we've talked about this a lot already), PJM has some interesting things going that could probably be great for a whole panel. At one of these discussions coming on, they're looking at two different major things. We just did a workshop with PJM states on this a couple of weeks ago. They are looking at both a carbon pricing rule and a pricing rule designed to factor in all of the state subsidies that are there, and trying to have a market response that tries not to unduly burden those utilities that aren't receiving subsidies at a particular time and readjust the market based on that.

There’s the DOE directive, and I included the last bullet point just for Professor Hogan, who always talks about the carbon tax, and we've always talked about whether or not that's something that's likely to happen, but Senator Graham has recently proposed one, so we don't know what that will be like, going down the road.

General Discussion.

Question 1: So, a common thread running through this conversation was the general heading of "rent-seeking activity," and this is not a term or an idea which is invented for the electricity sector or power sector. This exists all over the place, and it's not new. We know about this as a matter of political economy all the time. When people come forward with proposals for their favorite technology and why it's so terrific, my first response is, "Great, why don't you build it? And you pay for it and see how you do." And of course they say, "Well, I can't actually do that because it's going to lose money in this marketplace, but it's so terrific, you should pay for it." And they want some kind of mandate, and that always strikes me as a problem.

There are, broadly speaking, a couple of ways to imagine dealing with that. For example, sunshine is one of the strategies, and so one of the things you can imagine regulators would take as their responsibility is to really probe down that the assumptions and the analysis and how good is this story and do these analyses hold up?

My favorite story is that we have to build a lot of this really expensive technology in order to make it cheap. And that is a learning by doing argument, basically, and that's not a completely crazy idea, but when you actually get out your pencil and look at the numbers as to how much benefit that really is and how much you would want to subsidize a technology in order to achieve that benefit, it turns out to be a pretty small number. So it doesn't actually justify going forward with many of the things that the people who appeal to this argument want to see done.

So I use that as an illustration of the conceptual problem. What is it that regulators can do, in particular, to either expose the rent-seeking activity, to provide transparency and sunshine, and if necessary, to isolate (as I have recommended in another context) the cost? If a state wants to do something which I would recommend that they don't do, at least we can have a system where they have to pay for it, as opposed to having a system where they can impose the cost on everybody else through some kind of activity. I don't know how to solve that problem completely, because it's so ubiquitous in the economy, but how do we make progress on that problem here?

Respondent 1: I'll say a couple things in the effort to be controversial and then someone else can smooth over the feathers here. First let me say, I certainly recognize the sector is fraught for that sort of rent-seeking behavior. It's certainly not the only sector where that sort of thing happens, but the nature of the regulatory compact and monopoly utilities in particular makes that particularly a ripe opportunity. That said, I would ask whether or not we would have universal reliable electric service without federal mandates and subsidies. Or, for that matter, without state mandates and subsidies.

Just as a purely anecdotal example, I recently when I moved to New Mexico. Four years ago, I moved into a house about 15 miles or 16 miles outside of Santa Fe, which, as some folks who have worked on broadband issues know, is in this area that they call the "donut" surrounding a metropolitan area. So, metropolitan areas tend to have pretty good broadband connectivity, like high speed internet, and then there are federal subsidies for areas, rural areas, but those don't begin for a little ways outside of metropolitan areas. So I moved into an area where I literally could not find a company that would provide internet to my home. To make matters worse, I was on a well on that property, and it was suffering a massive drought, and the well ran dry, and there was simply no opportunity to connect to any other water source. They had to have water hauled in to the holding tanks to get water.

And I think that in the electric sector, we've done substantially better than that, partly because of the idea that we're going to subsidize our neighbors. There's folks at the long end of rural lines that are going to be paying the same rates that we do, even in the city, when the cost of service is significantly lower, and I'd say that, overall, that's worked out pretty well.

And it's similar on the generation side, I would question whether or not we would have the significant generating assets built in the '30s, '40s and '50s that we do if it weren't for significant federal involvement and interaction with that sector, and I'd say we face now a mandate, with climate change, to turn those technologies over. And while our carbon price will generally move us in that direction and I would advocate for a carbon price (national or state or otherwise), I think there are good reasons for more specific policies on energy efficiency, on renewable energy, on storage, to ensure that those technologies, which we are pretty darn sure we need--not necessarily specifically one renewable technology or another, but in aggregate, we're pretty sure we need those technologies. And then we can think about the most cost-effective ways to get those technologies.

I agree that when taken to the most extreme version, something like, "Here's my little widget. Why don't you buy a million of those?" that can be a very perverse problem, and state regulators are posed those questions all the time. And I think the question is, how you differentiate between the overall need for technological transformation, which I think drives reasonable policies that are more specific than overall price, and those very specific mandates that can end up being just purely rent-seeking behaviors?

Respondent 2: One of the reasons why this problem is perplexing is because it's been around forever, and it's not likely to change, and it's not just in this field, the rent-seeking, trying to move a particular product. We were joking about something related to this before the day started. I'm from Illinois, and a famous columnist in Illinois said that we should change the state motto to, "Where is mine?"

And you see that behavior a lot. Take, for example, ZECs and nuclear. So, New York does it, and Illinois follows suit, in combination with other things designed to boost renewables and energy efficiency, and then there are a couple states where we've done a lot of work trying to figure out which nuclear plants were in trouble and which ones were likely to want something like that. And in one of the states where that wasn't really the case, the head of the company said, "No, we're really OK, but if everybody else is getting that, why shouldn't we want to get that as well? Ultimately, it could harm us in the market place if we're not getting that."

And the other distinction that I would make is that, a lot of times, it's not regulators who are doing this. It's legislators and governors who are doing this. For example, my theory is that the ZECs happened in Illinois primarily because nuclear power plants pay a lot of money to people in areas of the state where not a lot of people are making a lot of money, and they are the largest single contributor to the tax base in whatever town they're in. And but for those two facts, ZECs wouldn't have happened in Illinois, because it wasn't about reliability, and it wasn't about reserve margins and things like that. I don't know how you stop that, from a legislative and a governor's perspective, any more than you can in other industries where that's happening as well.

The other part about this for regulators is that rate cases is where they usually end up dealing with a lot of this stuff, and technology drivers end up being in various rate cases. As a former regulator, those are the worst places to actually sort these things out, because the difference in resources between the different players who were there is really pretty stark, in most places, and you're doing it based on a record that's developed. So, I don't know, maybe it's things like what PJM's talking about, where they're talking about rebalancing the marketplace based on the subsidies that the different folks are getting. But even if you do that, there's nothing to stop legislature X from coming along and doing the exact same thing, giving them something else, giving them a tax break, a property tax break or something else along the line, so I just don't know that there'sa magic way, a clear path, as to how you do something like that and still maintain state sovereignty.

Respondent 3: Picking up from that point, there was a debate, when I was working on a book for the World Bank on infrastructure regulation, about what the role of regulators should be with regard to subsidies, and the bank's position was that, "Well, if there are going to be subsidies, that's for the legislative authorities to decide." And my view is actually somewhat different. One of the roles of the regulators is to discipline those subsidies. The one thing you can say about legislators is that they never say no to any interest group that's looking for some special treatment. And I think what the regulators need to do is discipline the process. One way to do this is to make absolutely transparent what the subsidy is, and who benefits and who loses, or who's paying for it. And also, you can try to expose, where you've got an objective that the subsidy's designed to get to (whether it's to promote renewable technology or whether it's to do whatever, expand the grid), you can make it clear exactly what the purpose is, and then discipline that, so it's targeted effectively at what it's supposed to do.

So, for example, if what you end up doing, in the case of expanding the internet, is subsidizing service to more affluent areas, that ought to be exposed. And so it ought to be really clear, and regulators should be absolutely clear about who's paying, who's not, and trying to impose a kind of price discipline.

The other part of it is what worries me. It's partly why I got so heavily involved with the net metering debate. In the case of net metering, to the extent there was a public purpose (I would argue that never really was much of one), the incentive was there was to take a technology for which the costs were well above market and bring it to commercial viability. But somehow, over the course of that cost declining dramatically, very dramatically, some people thought they had an entitlement forever to that subsidy. And then it does become a political battle. To emphasize the previous point, look at what happened in Nevada. The Commission actually tried to do that (end the subsidy) and then, basically, the governor fired the Commission, or most of the commissioners, and then re-imposed a pricing regime that just doesn't make sense. So there is sort of this political problem, but I think regulators have to be able to take the risk of disciplining the price, of exposing who's benefitting and who's losing, and also of putting tight efficiency objectives and actually phasing out the subsidy. If it has a purpose for commercial viability, phase it out, over time, so there's an incentive. Obviously, if you could eliminate the subsidies, that would make sense, but I'm not arguing you should get rid of all subsidies. There are legitimate reasons to have them; they just need to be disciplined, targeted and transparent.

Question 2: I'm interested in hearing the panelists' point of view on the role that corporate interest in green power or renewable power plays, and the degree to which that changes some of the traditional red/blue dynamics, and whether that interest is big enough to have the kind of influence to change the dynamic of shifting policies with changing administrations and legislatures, or is it just kind of in the noise--it'll be there a little bit, but it doesn't fundamentally change what we've traditionally seen.

Respondent 1: The overall trend is that it's a growing factor, and becoming a significant portion of renewable acquisition in some parts of the country. And that I think the rough amount of renewables driven by the renewable portfolio standards is thought to be about 60 percent of the amount of renewables that are installed now. But that was higher before, and it's declining. So those market-based purchases, whether they're corporate or utility purchases, are an increasing portion, partially because many of the renewable energy standards that are in place now are getting close to being filled, although there are some recent expansions—California, obviously, Oregon, a few others, and New York have upped their standards. So we'll see the role of renewable portfolio standards remain an important part, and if we see more of those standards, it'll be, again, a bigger part. But in the meantime, those market-based purchases are a significant portion of the overall market.

The way that they affect the politics and policy is mixed. The most interesting example that I can think of recently is Nevada, where there were big renewable energy purchases, mostly solar, by data centers, casinos, and others. And that sort of got into the soup of a time period when there were also very low western wholesale prices, and some of the casinos sort of thought, "Well, we want our own, too," but they weren't necessarily looking at renewable energy purchases. They were just looking at accessing the wholesale market. And those folks joined into a coalition together to push this retail choice constitutional amendment that went through last year and has to go again next year to become fully law. The public pressure for that, the public campaign, was all about renewable energy. It was all about "choice for clean," and it was run at the same time that there was this massive fight over net metering, and so I think most people that voted on it thought they were voting on a bill that would give them more renewable energy. In fact, all of the members of the coalition that pushed for choice, including Sands and Winds, which are relatively conservatively-owned casinos. Sheldon Adelson and Wynn, who are both big Trump supporters, signed a declaration last fall committing to supporting an 80 percent renewable energy standard in Nevada, and then, when the session came around, promptly switched their position to opposing any renewable energy standard in Nevada and wanting only choice. So the politics are mixed, but overall, as a market trend, it is a significant and growing portion.

Respondent 2: Think about where the best wind resource is, and think about where that is just in terms of the politics and how that lines up, and I think, whether it's due to the Apples or the Googles that are coming in, or people that want to build data centers and other things, or if it's just due to utilities, I think what a lot of red states are saying is that there's a great economic resource that they've got in their state and that they can harness. So that is becoming a real trend, I think.

Question 3: Speaker 1, you said in your comments that it's up to the regulators to sort of discipline this. I'll put it more succinctly. Regulators should kill bad legislative ideas

Respondent 1: Actually, not kill them, make them gently irrelevant.

Questioner: I prefer to kill them dead; I don't want zombie ideas continuing to walk around.

But in some of the analysis, when you say that, are you aware of any studies that are out there that have looked at the transfers from one state to another? So, for example, I've done some work, which unfortunately I haven't been able to release publicly yet, that looks at the Illinois ZEC program, and the general trend is that Illinois ends up subsidizing consumption in the rest of the PJM footprint. And I heretofore have not seen any studies really looking at that transfer, because as states subsidize stuff that is out of market and higher cost, and impose that on their consumers, they then suppress the price artificially in the energy market or the capacity market, whatever the case may be, to the benefit of the rest of the footprint. Now, to me, if I don't care about 1,000 jobs in the Quad Cities on the Illinois side of the river, then that's a loser, politically, and why aren't we seeing that out there?

Respondent 2: I don't think it is a loser, politically, because you're talking about the politics of your particular state. First of all, the groundswell from the public over energy markets and how they function is probably not that great. Even with the media and reporters to actually make that point, I think if you bring 1,000 jobs that average, whatever it is, it was like an $110,000 salary average--they're really nice jobs at that plant--and that impacts the property tax base that's there locally, and you have people thinking, "The next time it's my factory, or my industry…" you can't discount that. The politics are in favor of saving things.

Respondent 1: Part of the problem is that the people that are the recipients of the subsidies are the ones that dominate the politics, because they know more about the subject, and they're louder. So part of what I'm saying is that what regulators ought to do is say, "OK, in the case of ZECs in Illinois, OK, here are the benefits." The regulator needs to make it clear: "Look, Mr. and Mrs. Rate Payer, this is what you're paying, and this is what it's costing you." There's a balance. In the case you're citing, the state regulators don't have much control. But they can expose exactly what it's costing and who it's costing. So their role is to balance off the asymmetry of information that's in the marketplace, and, frankly, the asymmetry of information that's in politics. We have never suffered from politics that's too well-informed.

Respondent 2: I'll just add one more thing. I think the whole politics around jobs and energy is really problematic for the conversation, because it's a very low-job-intensity field. Most of the costs are not jobs. And if you really want to do a job, you can do it a whole lot cheaper by directly spending on those populations in other ways in other economic development matters. Now, that said, I don't think that ever is going to catch wind, that you'll certainly see lots and lots on all of the great clean energy jobs from NRDC. There are lots of them. There are way more than in coal. But I think it's a general problem of this diffused cost versus concentrated benefit. And the folks who have the concentrated benefit are going to be lobbying heavily for that benefit, and are going to be very politically powerful. And I think, ultimately, that's what we're seeing at the federal level, with the, whatever it is, 75,000 remaining coal miners in the country that are asking for billions of dollars of federal subsidy, and there's a very concentrated political benefit for that.

Respondent 3: And, from a customer point of view, your point is well taken that the benefit of jobs being brought into a particular state or region sometimes is far outweighed by the additional increase in the electric cost to the balance of consumers in the state or in the region. So this cross-subsidization is tremendous, even from things like energy efficiency. Energy efficiency participants love it, because they're getting a rebate of sometimes up to 75, 80 percent of the cost of a project, but their neighbors are all paying for it, right? So if you've already done the work without getting the rebate, and now you're paying for somebody else getting it, you may not be so happy about it.

I always use the extreme example of net metering, where it's the have nots who are subsidizing the haves, right? It's the people who can afford to put solar panels on their roofs or storage batteries in their garages who are being subsidized by the people who can't. And if you take that to the extreme, nobody can really get off the grid because of that. You take it to the extreme, and if I'm the last man standing that doesn't have a solar panel on my roof, my electric bill will be about $2.5 billion a year to pay for the system.

Respondent 1: Although if you made that too public, the fact that that the rich are benefitting from the rooftop solar subsidy, Trump might reverse his position on solar energy.

Respondent 2: I'm going to hold off on the net metering point, but I will push back on energy efficiency. I think energy efficiency is one place where the jobs argument actually makes a lot of sense, because the bulk of the benefit of energy efficiency is driving down customer bills across the board, which means most of the job benefits out of energy efficiency are secondary job benefits, so that's actually a net economic benefit across the community of customers with more money in their pockets, more money to spend on lattes and less on kilowatts.

Respondent 1: Let me expand on that, because that's one of the things that are so interesting. If you have net metering, it distorts the incentives to do energy efficiency. And, in fact, you actually block certain energy efficiency or capacity efficiency technologies--you keep it out of the market. And so one of the things regulators really have to do is balance off what they're really doing, because you may make a lot of unconscious decisions regarding technologies that you're actually keeping out of the market.

I actually agree that the jobs argument is bogus, in general. You kind of balance off the jobs you're adding with the jobs that you lose because of rates. In fact there was a study; it was done by Arizona State on exactly that question. That really showed that this is how you balance it. You could argue about what numbers they used, but, at least methodologically speaking, that was the correct way to look at the jobs argument. You've just got to evaluate the full thing.

But regulators have to be very careful that when they're promoting a particular technology, they're not blocking other technology that might be more advantageous, or that has its own commendable virtues that you want in the market place. And actually, one of the fascinating things about the net metering debate is that net metering really does mean you are keeping out certain kinds of energy efficiency technology. You're taking out of the market price signals that actually could help energy efficiency.

Question 4: It's not just legislators who are faced with these requests for special treatment, and I'll give you an example. In Idaho recently, I think it was a couple years ago, they approved a tariff rquested by a utility for unspecified R&D. And we see it all the time. They say, "OK, the economics of utilities are changing; we've got the utility of the future, what does that mean? We have to respond. You, commission, need to come up with something to help their business model, so think big thoughts." And so we are in the midst of it, and I don't want to just say it's the legislature that has all the wonderful ideas that we're trying to kill. Actually some of these are coming from utilities and some are coming from regulators themselves.

Respondent 1: And never discount the fact that the folks who have power will play one off against the other, and then try to figure out where they can get the better deal. I'm assuming, in that case, you gave them an unspecified amount of money.

Questioner: Billions. In California there is a history of utility spending on R&D that was authorized in rates, and at some point, I think in the '70s, it was put into a statute that they were allowed to seek R&D funding and rates. And then in the '90s, with the effort towards deregulation (I won't go into that history fully) in California that actually went into a state pool for funding of energy-related R&D, funded by utilities. That was a ten-year authorization that ended about eight or nine years ago now, and then the utilities position was, "OK, no more R&D." We actually went to the Commission and said, "Well, you still have authorization to spend on R&D, why don't you continue to fund the state-led R&D effort?"

Respondent 1: And that makes a lot more sense than giving it to a small utility and saying, "OK, utility, you become the equivalent of a national laboratory, and we want something big."

Questioner: Exactly. So the resources are pooled, and the projects are competitively bid.

Question 5: I go back to this question of state action in the environmental space. I don't hear enough discussion in that context about the role that markets can play, both positive and negative. One of the negatives of capacity markets is the fact it keeps old clunkers around. Now, that may be the economically optimal solution, but, on the other hand, one of the benefits of an enhanced energy-only market is that it drives a lot of clunkers out of the market. In fact, this morning Vistra announced they were closing Big Brown, which is a very large, very old and very dirty coal plant, as well as a couple other smaller units. Yet, even the environmental groups, most of them are at best neutral on markets, or even oppose the implementation of markets in various forms, or are critical. For example, the Sierra Club has been critical of retail competition. But retail competition actually drives a lot of the competitiveness in the competitive markets--having lots of buyers, so you don't have buyer side power.

The truth of the matter is that over the last 18 years, the power fleet has dramatically cleaned up. There have been substantial reductions in carbon, and will be even more now, and it wasn't the intent of the market design, directly, to improve the environment, but that's a substantial effect, and environmental groups appear to want mandates and regulatory solutions. I don't know if it's because it makes them feel better, or because they can go to Paris and say, "See what we're going to do?"

Respondent 1: Well, first of all, I just applaud what you all have done with cleaning up the grid. I think it's fantastic.

For me, I come from a legal background, and we look at what laws we can implement to try to clean up the environment. So I think there's a sort of a cultural element to figuring out these problems. And I will say that over the years, having always lived too close for comfort to Texas, I've often looked over the border and thought, "This is worth looking at. What is working here that's generating all of this wind? We're seeing coal closures…something is working here." And so I would say I'm very open to those lessons. I thought your discussion yesterday…and we've been very often critical of capacity markets as well. I think at a certain point, when a jurisdiction decides they're going forward, we work on design issues, but I think there are ways that markets can work.

I think the maybe the difference of opinion (and correct me if this isn't a difference of opinion) is that there are often still market failures and places where externalities are not priced, where there are significant impacts from various portions of the power sector. So, while it's possible that the market itself, which is perfecting over other issues like price and cost, will also happen to get it right on carbon or other pollution, and it's great when it does, there are often times when it doesn't. And so then, how do you design corrections to that market that ideally limit the cost impact on customers, but also get these other environmental benefits?

I think there's a reason that cap and trade was initially a mostly Republican concept, and it was a way to create a market to minimize the cost of achieving the known needed carbon reductions. We stuck with that through Democratic and Republican administrations, and it's now firmly thought of as a progressive idea, I guess. But I think, ultimately, it is a market-based solution.

A portfolio standard is similar. There is a mandate behind it, but it also creates a market to allow the lowest-cost way of making sure that you get a certain amount of renewables. Now, you could argue that what you need is not a certain amount of renewables, but an overall carbon reduction, and that a carbon price or a carbon cap might do that more effectively. But it does use some of the instruments of a market.

Respondent 2: However, with a renewable portfolio standard, the problem is once you hit your target. It's like net metering or something. Trying to kill it because it's no longer relevant…you'd think that you were a child molester. This from folks that otherwise know better, like the wind industry itself. All we were suggesting and all the bill was suggesting was, “Declare victory,” because we blew through the mandatory requirement. We were actually producing a lot more RECs than were necessary. The prices of the RECs, as a consequence, are a non-factor. Yet, there's a time when I think that the environmental groups would actually benefit their credibility by saying, “You're right, let's declare victory on this and move on to whatever the next real problem is.”

We faced the same thing when we declared victory with the CREZ lines—when we said that, henceforward, we’d go back to the really novel idea that you’ve got to demonstrate need before we build transmission. And, frankly, at least in Texas, that's not a terribly high hurdle—to see congestion build up. But, nevertheless, we caught a lot of flak. Now, on that one we were supported by the powers that be, so we were able to do it, but…

Respondent 3: I think there's another interesting point related to that. A lot of the environmental organizations just aren't set up to look at markets. They're set up to think about things in terms of the engineering, the equipment, the technology, what's going to drive down the emissions. And, having been a head of agencies on both the environmental and the energy regulation side, I can say that, though things are changing now, there wasn't a lot of good cross-silo talk between the two. I mean, for some of the state groups that we work with, because we work with both air and energy regulators, we've actually held seminars on the “101 of environmental regulations” for the energy folks, and for the environmental folks, sessions like, “How does power get bid into the market?” Just basic kinds of stuff, and we’ve been finding that there just hasn't been that kind of education, so even some of the air regulators, who are really good at their jobs, may not have a real great understanding of what impact on the markets a particular decision on a control technology or something else that they're doing might have.

Respondent 1: What's interesting is just watching that interaction between environmental groups on some of these issues. The politics of this are very difficult, just within the environmental movement, or between people that have a more nuanced understanding, along the lines of what Respondent 3 is talking about, to people who say, "Oh, it's renewable, therefore good, therefore do it, period, end of discussion." The classic example was Rocky Mountain Institute, which issued a thing about demand pricing, actually along with NRDC in California, saying, "This could be a really important mechanism for getting more capacity efficiency," and then, when pressed, to some extent NRDC backed away from that position, because they're getting so much pressure from other groups that said, "Wait a minute. If you do this, then it may deter the sale of rooftop solar units." And so there's the politics among environmentalists which, without considering anybody else, are extremely complicated and difficult.

Respondent 4: You see it show up in the debate, too. You'll hear a lot of people talk about, "We should be 100 percent renewable." Well, all right, that's fine to have that as an opinion, but what's the object of the exercise? Is it to drive down greenhouse gas emissions, or is it to have 100 percent renewable energy? Because, depending on your answer to that question, you have very different pathways that you go through, and that's just to amplify the point that that's a debate that plays out pretty mightily within the environmental community, too.

Respondent 3: Since we're getting picked on, I'll just remind folks that the environmental community is not the only community where politics can lead and policy can follow. I think maybe the most interesting example that comes to mind is in the U.K. As some folks know, the real end of coal was not driven entirely or even mostly by emissions. There was access to low-cost gas, and Thatcher hated the coal unions and was very thrilled to shut down coal plants, because they were fomenting labor politics and even Communist politics, and she wanted to go after them. Whereas here in the United States, even though somewhat unionized, the politics have flipped on that.

And so I think there's lots of ways that politics can lead and policy can follow. I think the question about the difficulty of declaring victory is a fair one. I think that the other side of that is that victory is a moving target, right? You said many states have advanced their RPS, because in some ways the original RPSes of 10 and 20 and 30 percent were vastly more ambitious than a 50 or 60 percent RPS is now, because the prices were insanely different. And you had bipartisan consensus to support a twenty percent RPS when the cost of wind was 10 times the cost of the wholesale market. And now you can't get bipartisan consensus for a 50 percent RPS, even though the cost of wind is lower than the marginal cost of many of the operating units in the wholesale market. So it's a moving target, but still, point taken.

Question 6: When you talk about baseload generation, normally you talk about coal and natural gas and nuclear. Will you see that, in the future, those variables, like offshore wind, will be considered baseload?

Respondent 1: Offshore wind, depending on where you're at, does have extraordinarily high capacity values, and, actually, a friend of mine recently sent me this really cool website that tracks wind speeds around the world. But it obviously uses a model, It's not perfect. But it's phenomenal, and it's actually quite beautiful. You can see that the oceans are just constantly very windy relative to the land almost anywhere, and that the middle of North America is kind of an exception with regard to how consistently windy it is, but even still, offshore wind is by far a more productive resource. So I think, yes, if we can figure out how to even close to cost-effectively capture some of that offshore wind, it'll be close to a very constant resource in some place, especially as you get further offshore.

That said, I think the concept of baseload is increasingly obsolete. I think flexibility is probably more important, already, than baseload, and so the actual value of something that's on all the time, I think, declines, and you have to weigh that against the huge consequences of something that is on all the time, relied upon, and then can go offline because of some maintenance issue, and then you need a bunch of other resources to backfield that. So I think, as we see more intermittent renewable resources, more storage capacity, and more other flexible resources, I think the concept of needing baseload will become increasingly obsolete. But, that said, yes, there are high capacity values offshore.

Respondent: If I can just add to that, I made a visit to the U.K. a year ago. The Brits are thinking about the integration and their area differences in wind speeds to try to integrate areas that are relatively lower wind speed with areas that are higher wind speed into a system that would help to provide more of a baseload concept for their increasing dependence on offshore wind.

There are a number of problems, though, with maintenance of offshore wind that you wouldn't have onshore. Sea conditions, and the length of time it takes to get a boat out there. It may be a matter of 10 hours before a boat could get out there, just because they don't even try it in sea conditions more than six feet. So there are issues with maintenance of offshore wind that make outages much more difficult to deal with. But onshore, I think the fact that it's spread over a large geographic area, and that there are differences in meteorological conditions, make it more possible, but, again, these things have to be integrated and there does have to be some back-stop system supplying it. With respect to offshore wind, we're relative novices at that area, compared to the U.K., but I'd encourage you to look at the U.K's efforts in that area.

Question 7: I have two questions for the panel. The first is, all of the presentations made pretty clear that in the Northeast and in California, you've got a long list of clean energy policies. The politics support that, so we'll put all of this out there and we'll see what works, right? But in the rest of the country, the politics are not that way, and so I guess my question is, where do you see the most significant development for the clean energy transition, outside of the Northeast, and outside of California. Say you're an environmental group, you got to pick one that you're going to put your emphasis on. You want to make a big splash. What do you focus on? Is it the $10 billion of wind investments by Accel and AEP? Is that the biggest thing that's happening outside of that area? Is it the electric vehicle charging investments in Nevada that could be done in different states? Is it something else? So, if you've got to pick one thing, what's it going to be? So that's question number one.

The second question is, the Northeast and California have all of these great policies on paper, but to implement them, for a lot of them you need lots of new big generation, and you need transmission lines. And it is in California and in the Northeast that it is most difficult to build these types of projects. So how do you address those hurdles in those states?

Respondent 1: For a while, I don't think there was a governor in the United States that wasn't arguing that his or her state was the center of the renewable energy industry. I mean, literally, I think every governor had the same speechwriter. That has little less cachet than it did a few years ago. But I think some of the things that are interesting are, for example, states that are exporters, like New Mexico and Wyoming, for example, have special transmission building authority just to export wind, and there may be some other states as well.

Respondent 2: North Dakota clearly has an interest in exporting wind, so, I mean, those states obviously have some sympathy, because they see revenues. And, obviously, farmers who are going to host wind farms are going to be very interested in doing it. You can see that in a number of states. So there are politics in the Midwest, in particular, that generate support.

In the South, it's more complicated, because renewable resources aren't there quite to the same degree. But even there, you can make arguments about saving money and efficiency and you can make some of the environmental arguments. I just think the politics aren’t as receptive. But the big thing that would change things is if you had an economic stake, as they do in North Dakota, Wyoming, New Mexico, and some other states that might not otherwise be sympathetic. It makes them more sympathetic.

One of the things that drove a lot of the wind development in Texas was the idea of energy independence and being in the interest of national security. Well, now, the low price of gas and the quick availability has made the national security argument largely go away, so some of the right-wing support for renewable energy has gone with it.

Respondent 1: We've seen, in New England, that transmission is absolutely difficult to site. New Hampshire seems to be blocking Northern Pass to the best of its ability, which is meant to bring hydro energy down into Massachusetts. New Hampshire's not getting much out of that, so why would they let a line get sited through their territory?

National Grid has also done a clean energy RFP with three states, Massachusetts, Connecticut and Rhode Island, and a lot of the projects that were selected were standalone generation, renewable generation that didn't require transmission. And that's because the states, even though they wanted and recognized that large-scale renewables were cheaper, they couldn't agree on a cost allocation of the transmission itself. So if you can't align the benefits that you're getting from the clean energy attributes with the cost of the transmission that's going to get it there, then kind of the whole coalition falls apart. And now we see Massachusetts going it alone. They want to put in 1.6 gigawatts of offshore wind and, as I said before, 9.5 terawatts of clean energy--most likely hydropower or a combination of hydro and wind firming each other up. But that's a relatively small state to have to pay for all that transmission and all that offshore wind. So you can imagine what the price of electricity in Massachusetts is going to look like by 2027. Right now it's 15, 16 cents in the summer. If there are gas constraints on the system in the winter peak, due to pipeline constraints, the price has spiked up to 30 cents a kilowatt hour, and the cost of this offshore and this new development will likely bring the rates up 50, 60 cents a kilowatt hour.

Respondent 3: Or maybe you should just install some solar on your roof.

Respondent 2: I work in Massachusetts, but I don't live there, thank God. I mean, it is costly, right? So the question is, what happens when the first set of offshore wind, 400 megawatts, comes into play, and people see is it expensive? Are the prices coming down, or aren't they coming down? People want to be able to build that offshore wind for economic development in a particular state, but after a while the cost is maybe prohibitively expensive, to the point where, if there's an RFP for that power, and the utility brings that RFP or that PPA in front of the regulator, that's potentially the only way the regulator can stop it. But we have to bring reasonable, rational economic results in for power purchase agreements, and if they are not reasonable and rational, maybe the DPU would put a stop to it.

Respondent 3: The big thing, to me, is the wind resource in the middle of the country. Now, the corollary to that relates to your second question, about transmission, and it's going to remain difficult. If transmission lines have to cross several different states, all of which have different criteria to judge transmission lines, it makes it a very difficult proposition. Somebody was speculating recently whether or not, under the new definition of cooperative federalism, that might mean at some point that the feds are taking a much larger hand in transmission siting. Everybody's going to have their own opinion about that. But I think that's a debate that's going to happen.

Respondent 1: Implicit in that is the states switching between NIMBYism and environmentalism, because I think sometimes as an excuse, NIMBY folks often talk about the environment, but that's not really what it's about. Actually even the environmental movement there's a bit of a split about transmission, and so the politics of that are very difficult.

Respondent 4: In response to the original question, I'd say that it's hard to pick one thing, and I'm generally a silver buckshot rather than silver bullet believer in policies. But I agree that the trends we're seeing on prices--the flip from renewables being a high cost option to the lowest cost new resources--is really significant, and you're just seeing that playing out, with utilities really wanting to jump on it and big corporate buyers wanting to jump in on it. My hope is that even as the PTC and ITC phase out, we will continue to see that trend. I think that's also leading the politics--the number of utility executives around the country that have responded to the move to roll back the Clean Power Plan by saying, "This doesn't affect us. We're still going forward, we're going to hit the Clean Power Plan targets or beat them significantly." I think that's being driven by those price trends, among other things. There's politics, too.

And then, as to the transmission, I agree it's hard. I think that when things are hard, the tendency sometimes, if you're transmission planning, is to try to keep your cards close to your chest. You try to get all the property rights along the way, and then you sort of throw out your plan at the very end so you can get it permitted. And I think that has tended to backfire. I think this sort of more participatory, open, transparent planning process…it's very hard, it takes a long time, nobody likes it, it feels like pulling teeth, but I think it's, ultimately, the smarter way to do it. And doing that, not just one transmission line at a time, ideally, but, particularly in the West where there's a lot of public lands, having the federal agencies lead a process to identify the lowest-impact areas to site transmission will be more likely to bring about environmental support, certainly. Where the landowners are less significant (in Nevada, I think 80 percent of the land is owned by the feds), that can be really meaningful. Now, of course, where there are private landowners, you also have to bring them into the process. But, overall, that sort of smart from the start participatory process, I think, is the only way to go about what is inherently a very difficult challenge.

Respondent 2: Well, the other thing is that the variances among state siting laws make things more complicated. So, for example, there are only a handful of states that will allow non-utilities to use eminent domain, so a wind developer who wants to build transmission really either has to go without eminent domain (which, if he or she can do it at all, is going to drive up the price), or they have to get a utility in the state to use the eminent domain. And then you get into this issue that was raised in regard to New Hampshire and other states that have taken this position where, “You're not going to build it across my state unless you show me money for myself,” and so the whole legal structure for siting is really ripe for reform that, politically, is probably not so likely.

Question 8: When one thinks about state climate policies, you have to sort of ask yourself, what's the goal here? Is the goal really to cut statewide emissions? Is the goal to influence an ultimate federal policy? Is the goal to create a testbed for new technologies? There are lots of possible goals, I think, ultimately. Folks who are working on carbon-related regulation at the state level probably hope someday to see a federal policy that's probably a first-best.

One thing I worry about in a current context of kind of renewed state excitement about doing all things related to carbon, particularly where I come from in the northeastern states, is how this plays out when and if we ultimately do have federal action. The folks in this room maybe didn't follow it, but last year there was really important bipartisan reform to TSCA (the Toxic Substances Control Act), and one of the biggest barriers to getting that bill done was actually the question of preempting state-level authority to do things that had been occurring because TSCA was so ineffective. So Barbara Boxer, from the California delegation, was adamant that they not lose their authority, or as little of it as possible, in the presence of this federal reform. And yet preemption was necessary to create a national market for the compounds in question. So does anyone on the panel think that this is a concern? That as we deepen our commitment on carbon, as we go to higher carbon prices and that money is flowing somewhere, probably to spending on various policies, hopefully effective spending, does that make the federal outcome harder in the long run? We may be really excited over the next three years about doing this, but that could actually make action that we really need to take at the national level, the action that Congress needs to take, more challenging. I’m curious what your thoughts are.

Respondent 1: To your first comment, about goals, I think that there are lots of reasons for doing it. I don't think any jurisdiction is or should be limited to one of those. There are lots of good reasons to move on this.

As to the question of preemption, I can see a theoretical concern, I think it obviously depends on which of these policies we're talking about. We're talking about renewable standards and net metering and energy efficiency and carbon standards and vehicle exportation. Many of these things are really pretty well within the traditional realm of state regulation of their electric utilities. And so I don't see a huge threat. I think it's mostly about building momentum on technology and cost.

As to specific carbon policies, I think that's probably where there is the most potential for conflict, because there are certain kinds of national policies that you can imagine would be in conflict. The Clean Power Plan really wasn’t one of them, because it booted it back to the states anyhow to achieve these goals or more, and so I don't think there's much of a concern there, but were there to be, for example, a congressionally passed carbon limit or tax that was across multiple sectors and not just the electric sector, then I can imagine a possibility of a conversation about preemption. And I can imagine that you're absolutely right. California's program is probably more ambitious than anything we'd be likely to get out of a pretty good Congress. And I can imagine that that conversation would be tough, but I would also say that Congress and California have a pretty good history of ironing those things out in the end, with the Clean Air Act waivers on fuel standards, so I think we can get there, and I think having California there pushing to say, "We want to go even further and faster," is a mechanism that overall…I don't think all of the other smaller states will get that same level of deference for preemption exemptions if something like that were to happen. But I don't think it's needed. California's big enough to make a market by itself.

Question 9: I wanted to circle back to the notion that came up that the ZECs are rent-seeking behaviors that are likely to distort market outcomes. I find that an interesting interpretation, because you've got an example here of people interested in nuclear power intervening in the regulatory and political process to get some favorable treatment of their technology. And it's interesting that we don't talk about the people interested in wind and solar technology intervening in the regulatory and political process to get favorable treatment for their chosen technology as rent-seeking behavior. And so I had put a paper together a couple weeks ahead of Secretary Perry's letter, and he cited it. But the basic argument here was that, because we subsidized renewables instead of putting a price on CO2…We talked yesterday about the importance of getting prices right. The only way you're going to get prices right in the market and address climate change is to have a price on CO2 that's appropriate. And that means you don't have command and control things on top of that. They are not complementary. They are distorting.

So what we've got on our hands now is we've got renewable mandates and subsidies that have distorted the marketplace. They've reduced the cash flows to non-peaking generating resources, and so we've had interventions, now, to offset that, the first one being in California. You've got an intervention, because in a competitive market result, you would not have enough flexible generation to follow net load. And the cash flows in California don't support it, so now we have to intervene and pay for flexibility. And if you had put a price on carbon, in an efficient market result, we wouldn't have nuclear plants closing down when it's cheaper to keep them running than it is to replace them.

And so I think that we've got a very big problem here, which is that these state programs are inconsistent with the marketplace. They are contradictory, and the more we go down this road on a state-by-state basis, with compromising negotiation giving us this mishmash of market and command and control, we're going to have very ineffective results. And everybody's been praising California, but if you look at the results of the California mishmash, since they started renewable portfolio standards in 2002, renewables have gone up from two to 15 percent. CO2 emissions from generation inside California haven't gone down at all. You close down the nukes, you increase gas from 50 to 60 percent of generation, to back up and fill in for this stuff, and so what do you see California doing? You've got an Energy Imbalance Market that's trying to use a price mechanism to efficiently reduce the cost of this enormous inefficiency you've created by mandating too many renewables. Reactions?

Respondent 1: Well, I think it's fair to say we disagree about a few things. I don't think the Secretary cited your paper's point, if you made it, that there should be a federal price on carbon. And so I think that that's a starting point for differentiation. I think I would note that the nuclear plants in California, one of them is still up and running, and the other one closed, not because of any California policy mandating closure, or frankly, for that matter, because of price concerns around renewable energy, but because of a significant maintenance issue that was unexpected and came up, and really the owners of that plant felt that they couldn't safely operate it. And the other plant is facing similar concerns about the fault line that it's been on top of its entire life and other ongoing safety and maintenance concerns as the plant gets older. So those aren't market pressures for renewables driving either of those resources out. I can't speak to the plants in the Midwest.

So I guess I would disagree that the California electric sector is facing horrible pressures from renewable energy. There are certainly integration challenges, but all resources bring their own integration and maintenance challenges. Renewables are not in any way unique in that. And, yes, renewable energy has been subsidized (that's what the Production Tax Credit is), and so have nukes, and so has coal, and so has gas. In my state, the state statute for royalties on gas are the lowest in the country. The lease rates were set in the 1930's and haven't been brought up since then. They're lower than the statutory lease rates in Texas, and way lower than what you would pay a private landowner next door. Those are clearly state and federal subsidies for all of these industries.

So my point was not to say yes to all subsidies all the time, but if you're talking subsidies, you need to recognize the significant subsidies that underlay this entire industry and have done so for a long time. I would just respectfully disagree that renewable energy is causing massive inefficiencies or problems in the market that are significantly different in kind from integration challenges that any resource brings about.

I'm just curious. In the paper, how did you factor in the subsidies that nukes have gotten, which may exceed what renewables have gotten over the years?

Questioner: With regard to subsidies, not all subsidies are distorting. So there's a big difference, for example, between the Investment Tax Credit and a Production Tax Credit. The Production Tax Credit, since it's based on the volume of production, has a big distorting impact on bidding behavior, particularly in an over generation situation, where your opportunity cost is to lose your Production Tax Credit, which is how we generate these big negative market-clearing prices.

Nuclear was subsidized enormously by the Manhattan project. It's a sunk cost kind of subsidy. So, the nuclear subsidies right now are things like the eventual handling of the spent fuel and so forth, Price-Anderson on liability.

If you try to come up with some weighting here on what is the size of these subsidies, we have enormous subsidies on renewables right now. The scale of subsidization is out of whack. If you dismiss it with, “Well, everything's subsidized, so we don't have to worry about subsidies,” we've got enormous subsidies on wind and solar on top of the mandates and on top of the net metering subsidies. So we've got some serious market distortions, and there is a general rule here that because we've distorted prices, we're not getting a valid market test on whether things are economic to retire or not. And where I'm from in New England, we've got the Vermont Yankee plant that was economic to keep running. It's closed down because of where the power prices are, and now we've got Pilgrim closing down. CO_2 emissions in 2015 went up seven percent. And when Pilgrim closed down, they'll go up even more, because it's a bigger nuclear unit. So this idea that, “Well, nukes aren't competitive and they're getting a bail out here…” They are suffering from these market distortions linked to these renewable mandates and subsidies, and we are ending up with a CO_2 boomerang as a result.

Respondent 2: Actually, the MIT *Future of Solar* study, which was looking at net metering in part, was arguing that some of the subsidies may not have any benefits for the solar industry. They didn't get into what the carbon benefits were, but they were saying that these subsidies are such that they actually hurt the long-run evolution of the very industry they're designed to promote. The vendors will make more money, but the long-term economic viability of rooftop solar is going to diminish. So some of the subsidies are designed for somebody that's clearly rent-seeking, because they harm the very industry they're supposed to protect.