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Rapporteur's Summary*

Session One.
Interregional Transmission Services and Operations: Beyond Order 1000

Increasing development of intermittent resources and reduced reserve margins of traditional resources require leveraging diversity in regional supply and demand. Western utilities are moving towards an energy imbalance market to meet these emerging portfolio challenges. Some utilities and RTOs have developed voluntary coordination and congestion management agreements with varying governance structures and sophistication. These agreements can result in a patchwork of ad hoc bilateral agreements without full integration of the markets. While FERC directed interregional planning reforms with efforts in its Order 1000 initiative, it did not address operations or transmission services reform across transmission provider seams. The Commission's Order 890 Rulemaking (2007) and the Inquiry into Transmission Loading Relief Reliability Standard and Curtailment Priorities (2010) have not produced significant advances in operational coordination. What opportunities are there to ensure maximum utilization of infrastructure across each interconnection and leverage interregional diversity? What can be done to move toward more efficient dispatch and congestion management across each interconnection? What operational opportunities can be leveraged with the eventual implementation of the Parallel Flow Visualization effort? With the development of Order 1000 interregional planning processes and cost allocations, should the traditional "through-and-out" transmission rate structures with rate-pancaking across systems be reevaluated? Should contract path or point-to-point based transmission service be supplemented or replaced with compensation mechanisms based on loop flow impacts to neighboring systems? Under what organizational and process umbrella (i.e. FERC, NERC, NAESB, or Voluntary Regional JOAs) can opportunities for advancement in interregional operations be made most effect?

Speaker 1.
It certainly is a pleasure to be back at the HEPG. I've been away for a little while, but it's a real pleasure to be back with you again.

I thought what I would do as far as my opening remarks for the session is to focus kind of on the hot topics for the near term, if you will. That is, the things that PJM has been involved in most

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recently when it comes to seams coordination with our neighbors, and I'll talk a little bit about things that are going on with MISO as well. I will also talk more about PJM's other neighbors, both those that operate a market, like New York ISO does, as well as some of our neighbors to the south, and our market to non-market coordination.

I assume that the vast majority, if not all of you, are very familiar with PJM and where we are and what we do. So I'll skip by this pretty quickly, but in case you needed a refresher as sort of where PJM is, PJM is the regional transmission organization that serves sort of the mid-Atlantic out to Northern Illinois.

I kind of lumped the seams coordination issue, if you will, into three major buckets, the first being the coordinated operations between an entity like PJM and our neighbors and how we mutually respect transmission constraints as we conduct our operations both on a day ahead and on a real time basis. The second is how we kind of stimulate and manage and hopefully ensure efficient transfers of energy between areas of the interconnection, so into and out of PJM, and with our neighbors. And then finally, the third bucket has to do with how we coordinate our transmission planning efforts with our neighbors to ensure that we are conducting transmission planning in a coordinated way. I wasn't going to talk too much about that third bucket, although certainly we can get into that if folks have questions or want to go into it somewhat deeply. Instead, I thought I'd hit some more near term sort of things that are going on and that will hopefully result in improvements, even from where we are today, in how we conduct coordinated operations and planning in the future.

Somewhat recently, SERC established what they're calling a Reliability Risk Team. I'm not sure how long it's been around. But they have identified loop flows as a concern and something that needs to be investigated and addressed. And this was at least somewhat stimulated by the occurrence of transmission loading relief (or TLR 5) events early in 2016. TLR level 5 is where you actually get to the point of curtailing firm transmission flows on the interconnection. And, obviously, when you get the firm curtailments, that presents a concern, and it also stimulated a need for an investigation.

PJM is actively participating with this Reliability Risk Team. We have submitted systems snapshots and data and analysis that will hopefully assist our team in conducting its analysis. And we will continue to participate with SERC in investigating those events, and asking what can be done to enhance the way we conduct our operations together. I'm not sure exactly what will result, but it could be anything from additional operating guides or coordinated operations documents, or those types of things where we identify better steps and better procedures our operations can take to manage congestion on a day ahead or a real time basis, with the goal of not needing to get to the point of firm curtailments and TLR level 5's in the future. So we will be participating in that as that goes forward over the next period of months.

We've also coordinated more specifically with neighbors to our South and Southwest, TVA and Duke. One of the stimuli for these investigations was some concerns expressed by the North Carolina Commission that have to do with the effects of loop flows from resources that are external to PJM that have committed to PJM to be capacity resources. And so when energy is delivered from those resources to PJM load, the energy obviously flows across the Eastern Interconnection, and those loop flows could impact the North Carolina utilities. And so we have participated in analysis of what those anticipated effects might be. We have developed operating procedures and operating guides with these external entities, Duke and TVA. We will continue to analyze these events and project the system conditions for areas where we can coordinate our operations more efficiently. We've also shared areas of congestion that we've identified in these operational studies with our systems planners so that they can include those considerations, if you will, in their long term planning to see if transmission upgrades will be beneficial for relieving those areas of congestion that have been identified. But I'll talk more about the planning things as we go along. So that's just a couple of highlights again of things that we're doing mostly to our South and Southwest with respect to coordinating our operations.

When it comes to efficient energy transfers, one of the hot topics that's popped up recently with respect to PJM is that when an external resource commits to PJM to be a capacity resource, going forward we are requiring that resource to pseudo tie its output into PJM. In other words, basically to electrically move that resource into the PJM balancing authority, so that resource actually participates very directly, and PJM can actually dispatch the output of that resource like it does an internal resource. So, in other words, when a resource commits as a capacity resource, it's sort of all in for energy dispatch and all that that entails. There have been issues that have been identified with coordinating the operations of resources that are external to PJM, but will be following PJM dispatch.

We've worked very closely with MISO and with other external entities in which these external generators lie to coordinate these pseudo-tie operations as well. We have developed operating guides for the near term, but we're also discussing proposals as to how we can better account for these resources, these external generators that are going to be pseudo-tying into PJM in the long term planning processes, to ensure that we don't see near term issues in these external areas when these resources pseudo-tie to PJM. So, basically, particularly with respect to external entities where we don't have these market to market procedures that are already in place, PJM is committed to ensuring that the flows from these external units that are delivering energy to PJM and that are committed as capacity resources for PJM, that those flows are made transparent and are actually accounted for in real time operations so that those flows don't have negative impacts on those external systems. So we'll continue to conduct that coordination with those external entities in order to make sure that's the case.

So, going beyond the electrical movement of resources actually into the balancing authority, the other types of efficient energy transfers are really balancing authority to balancing authority transactions. We've done a couple of things recently with respect to making sure that those transactions are also as efficient as possible. We worked very long and very hard with MISO, and we conducted a lot of analysis on how we establish the prices that apply to those interchange transactions. We refer to those as interface prices. We have recently come to an agreement with MISO as to how we're going to move forward with our interface prices in order to coordinate that appropriately with our FTR processes. We're going to implement those changes coincident with the next planning year—that is, on June 1st of 2017. Obviously we will continue to evaluate how that operates as we go forward.

Another near term development with MISO (but one that has existed for a while with New York and PJM) is what we refer to as CTS, which is Coordinated Transaction Scheduling. The idea here is that, while historically interchange transactions between balancing authorities were bilaterally coordinated strictly by market participants on the basis of their anticipation of what interface prices will be, we implemented a process whereby market participants can submit essentially a spread bid to the two ISOs and say, "As long as the interface prices are at least so far apart, schedule my transaction in that direction." And we have had that operating with New York ISO for quite some time. It's been over a year, I think. The volumes are not tremendous at this point, but that's, I think, because we also have the concurrent ability for participants to continue to schedule bilaterally as well. So both options are available between PJM and New York.

We also just received FERC approval recently to implement a very similar process with MISO. So we will look to implement that the spring of 2017. And the process will work very similarly to the one we already have in place with New York ISO. And, again, we will continue to evaluate how these processes operate to see if there's more that we should be doing.

So let me get to the efficient planning or the coordinated planning efforts between PJM and our neighbors. PJM and our neighbors have had an Interregional Planning Stakeholder Advisory Committee for some time. We've agreed with MISO to make some enhancements to our inter-regional planning process to remove barriers to implementing cross border planning upgrades that we believe are mutually beneficial. For example, eliminating the third cost benefit hurdle--there's kind of a triple hurdle, if you will, that needed to be crossed, where a project had to be cost beneficial in each RTO, and then as well on an inter-regional basis. So eliminating the inter-regional test and making sure it's cost beneficial in both RTOs eliminates one hurdle. We had a 20 million dollar minimum cost threshold that we're looking at eliminating as well. So, really, the idea is to try to eliminate things that would have prevented projects that could be beneficial from being implemented.

We've also looked to coordinate our generation interconnection queue, so that when a generator looks to interconnect in an area that affects both systems we analyze that interconnection request on a coordinated basis and make sure the request gets a coordinated answer both from a timing as well as an analysis standpoint.

We also have a project that we're implementing to do a transmission upgrade very close to the seam between PJM and MISO. It's mutually beneficial for both of us. It's a tie between Duff, Rockport, and Coleman. For MISO it actually mitigates congestion in the southern Indiana area. From PJM's standpoint, it eliminates the need for an operating guide with respect to stability issues at the Rockport generating stations. So, again, the project is mutually beneficial for both RTOs, and the fact that the transmission owner AEP stepped up and agreed to fund the project kind of took the cost allocation issues off the table, which was beneficial for actually getting the project done.

So I'll mention just a couple more things that we're working on. One is what we call Targeted Congestion Studies with MISO. The idea here is to find targeted projects that are relatively low cost but have mutual benefit for the two RTOs. We have a relatively short list of about six flow gates or transmission constraints that we are analyzing. The upgrades needed to enhance those operations are relatively low cost, but we're working through some of the last issues to see if we can't get those projects initiated to help with that congestion.

Moving to some of our other neighbors, with respect to those to our Northeast, interconnection queue coordination really is kind of where the focus has been. If we do cross border projects with New York, the requirements currently are that the project has to actually cross the border in order to be implemented. So projects that are wholly within one or the other organization don't qualify as really cross border planning projects. And then, as always, the cost allocation issues do tend to hamper our ability to get projects in place and are really kind of the biggest hurdle to getting a cross border projects done with really any external entity.

And, last but not least, I wanted to mention the North Carolina Transmission Planning Collaborative to illustrate the things that are going on to the south of us. Again, we have agreed as a result of these efforts to enhance data exchange, planning, and information exchange. These studies have resulted in enhanced operating practices in order to mitigate the impacts of loop flows on our systems. And then, as I mentioned earlier, we have the SERC parallel flow studies going on this year that I think will probably result in enhanced coordination opportunities as well.

So I realize that was a lot to cover in a brief period, but hopefully it illustrates that there is a lot going on, from PJM's perspective, with our neighbors, with respect to increasing our coordination across the seams. I look forward to hearing what you'd like to hear more about in the discussion that we have later on. So thank you very much.

Question: Just a clarifying question. When you have market to non-market operating procedures in real time, is that where you would direct the generator to do something specifically, or is it impacting prices? To what extent are prices used in that process of having operating guides when you have the PJM side that has a market with real time prices and the other side that's non-market?

Speaker 1: It can take either form. The preferred route, I think, is for an entity like PJM to report our market flows on external entities, transmission facilities, to the IDC (Interchange Distribution Calculator). Then, when that external entity needs to manage congestion on that facility, they would initiate the NERC TLR (transmission loading relief) process, and PJM would re-dispatch our system in order to mitigate our market flows on that facility. So PJM would handle that within our market, according to our normal congestion management processes. And that way prices do reflect the re-dispatch that's necessary. So that I think would be the preferred route. However, we do have operating guides in place as well. So if there is a facility, for example, that we need quick action from, or we need to mitigate congestion in the near term, we can use switching procedures or we can direct generators to adjust their output, even if prices aren't impacted. And then we have "make whole" considerations in PJM. So it can take either form, but I think the preferred route for our market operations is to make sure these get in the prices as well.

Speaker 2.

It's a pleasure to be here. The title of my presentation is "Interregional Operational Opportunities in the West," and this is a very timely and relevant topic for us, and certainly one that occupies a lot of my time. There's a lot happening in California and throughout the West on interregional market coordination and regional markets in general. I think you saw Speaker 1's slide earlier that showed the organized markets in North America, and you see California out in the West is kind of an island. You have Alberta to the north, but suffice it to say, for the majority of the West, they still operate primarily in a vertically integrated bilateral framework. But there's a lot of in play right now that's changing that. A lot of utilities throughout the West are looking for opportunities for better regional market coordination, and CAISO has been kind of at the center point of that with some of our market initiatives that I'll touch on. And I'll talk about what's driving that as well, because I think it's unprecedented. I've never seen so much interest, in my 20 years at the ISO, in regional markets as we're seeing today.

A big driver of it, really, is renewables and renewable integration. And California is really at the focal point of that. We have a number of very aggressive environmental policies. They really fall into two tranches. There are the 2020 policies, of reducing greenhouse gases to 1990 levels. We have a 33 percent RPS goal. The governor has a goal of developing distributed generation, and along with that we have state regulations on once-through cooling technology for power plants that implicate about 12,000 megawatts of gas fired generation in California that essentially will have to retire and repower to comply with it, and it's impacting that nuclear power plants as well. We already lost one major nuclear power plant in Southern California. The second one in the north is up for re-licensing in 2024, and it's frankly quite uncertain whether they'll be successful in getting a new license. So there's a lot at play with these policies.

And then more recently we've had a suite of 2030 policies that came out last year. We have a 50 percent RPS goal now, by 2030, and a goal of doubling energy efficiency. These goals came about in some legislation passed last year. It was the California Clean Energy and Pollution Reduction Act. And, very importantly for us, that legislation acknowledged the benefit that having the California ISO transition into a regional market organization could provide to California. So that was really a pretty breakthrough piece of legislation for us.

You may not know that California ISO's Board is basically selected by the Governor of California and confirmed by the California Senate. If California's going to grow into a regional market operator, a lot of states will find that governance structure unacceptable, obviously. So the legislation acknowledged that point, and essentially said, "We're open to looking at transitioning the ISO's governance to regional governance." But we need to conduct a whole bunch of studies to identify what the impact would be to California and we need to see what that alternative governance structure would look like. So it really gave us some homework to do, and I've been one of the primary leads on that, trying to push that analysis forward.

Also, the Governor of California had an executive order for greenhouse gas reduction to 40 percent below 1990 levels. So, again, very aggressive environmental goals. And I would note that throughout the West you're seeing RPSes. Oregon just this year announced a 50 percent RPS goal by 2030. So you're seeing a lot of renewable development happening throughout the West. And I think all the utilities are dealing with the challenges that come with that from an integration standpoint, and seeing the value of better regional coordination.

Just to give you some context of what's happening in California, this chart shows a projection of renewable buildout through 2020. This is transmission connected renewables, and you can see that currently we have about 18,000 megawatts of renewables. But when you look at 2016 out to 2020, where all the growth is happening, it's in one technology, solar PV. And, again, this is just the central station large scale solar PV facilities, but you see them essentially doubling over the next five years, and that presents some very challenging integration issues for us. And I would note that we're also seeing in California an explosion of behind the meter rooftop solar. We have right now about 4,000 megawatts of behind the meter rooftop solar. They're projecting that by 2030 that will go to 16,000 megawatts. That's just an astronomical change that has all sorts of implications, not just operationally, but in terms of the business model of the utility in California, with the net energy metering, but that's a whole other topic. It's a big deal.

OK, so I know it's probably safe to say that all of you have seen our infamous duck curve. I won't spend a lot of time on it. It's really just highlighting the operational challenges with renewables, and in particular solar, where it's all about managing that belly of the duck. So during the middle of the day, when that solar comes up really fast, we're seeing, even today, operationally, over supply challenges, where we're having to curtail solar projects because there simply isn't anywhere to sink the power, and that's just going to grow. We're seeing the 2020 curve showing a net load of only 12,000 megawatts. We've actually this year been below 12,000. So the duck curve is alive and well, and we're ahead of schedule with regard to the operational challenges on it.

There are lots of solutions. I won't go through them all, but I'll highlight the one on the bottom of my list, which is deeper regional coordination. When you talk about "no regrets" policy, you know, you can do storage, you can do time of use rates to try to shift the load, but the easiest and lowest hanging fruit is having better regional coordination, where when we have this surplus, zero marginal cost renewable energy, we can find a home for it.

There are lots of barriers with trying to move power throughout the West. You have pancake transmission rates. You have balkanized balancing areas, and so having a centralized regional market just can help tremendously on that.

So one of the efforts we implemented to try to advance the ball on this a few years ago is our energy imbalance market. And essentially I call that the toe in the water. It's basically taking the real time market platform that California ISO has, the 15 minute, five-minute dispatch, and making it available to other balancing areas in the West. They're still in charge of their balancing area function, but all they're doing is leveraging our real time market dispatch, where we can simultaneously optimize our system and their systems on a 15 minute and five-minute basis. PacifiCorp was the first utility to join, back in the fall of 2014. NV Energy joined the fall of 2015. And we're seeing additional utilities come forward. This fall Arizona Public Service and Puget Sound Energy are going to join the energy imbalance market. And then the following year we have Portland General Electric. And, more recently, Idaho Power announced their intent to join by 2018. And I can tell you there's a whole host of utilities, even municipal utilities, that are studying whether they want to participate in this EIM.

So it's a great opportunity. We're seeing some really real tangible benefits from it, not only for California, but for the utilities that are participating. You can see the savings there through the end of 2015, and actually with the introduction of Nevada Energy this past fall we're seeing even higher benefits. The benefits in the first quarter of 2016 were 19 million dollars, and we avoided, in the first quarter of this year, 113,000 megawatt hours of renewable curtailment by being able to export that energy. That's about half of what we would have curtailed otherwise. So, some real significant benefits to that.

And PacifiCorp after their first year realized that, "Hey, this regional market makes a lot of sense for us. We want all in." So they announced their intention (and I have to be careful with my words here) to explore the benefits of becoming a full participant in the ISO. So that really triggered, as I mentioned, the legislation that came out last year in California, and this whole effort to examine what it means for California if the ISO became, in fact, a regional market operator, and California relinquished its governance control over the ISO.

If you're interested in the legislation itself, it's called SB 350. You can see the language here indicating their intent that we explore becoming a regional organization and the studies they'd like us to conduct. Basically, we have to look at everything from impact to rate payers, to emissions, to how it would impact jobs, to the California environmental impacts, impacts to disadvantaged communities, and the reliability in integration benefits. So that study work is underway. I've been leading that effort. We hired Brattle Group, a very esteemed consulting group just a block from here, to lead this study, and it's well underway.

I think you're familiar what it means to become a regional organization. You know, it's a consolidating of the balancing area function, having an expanded footprint of the market. And of course you get with that the benefits of alleviating the pancake transmission tariff rates that you have to deal with in today's construct. And it also, of course, means transitioning the governance into a regional governance model.

Real quickly, the study looked at two time frames: a 2020 case and a 2030 case. The 2020 case includes just the ISO and PacifiCorp. 2030 was looking at a much broader regional market, where we essentially assumed all the balancing areas in the U.S. portion of the Western interconnect are participating, with the notable exception of the public marketing agencies. So we excluded WAPA and VPA--and that by no means, means that those entities aren't interested in markets. This was kind of a compromise, and not being too overly optimistic in our operational footprint.

And the projected benefits, which we released a couple of weeks ago, are quite substantial. Not so much in 2020, with just PacifiCorp, but when you look at a 2030, the benefits to California alone from this regional market are projected to be a billion to a billion and a half dollars per year. A big portion of those is just savings in getting to the RPS target. If you can avoid renewable curtailment by having a regional market to sink that generation, it means you have to build less of it to meet your RPS targets. So there are huge capital investment savings in terms of meeting that RPS target. There are production cost savings also. The diversity of load allows you to avoid having to build new capacity. There's savings with that. And then, of course, there are benefits from being able to spread our operational charges over a larger footprint.

I won't dwell too much on the other benefits of regional organization. I think they're pretty familiar to this group. Obviously, reliability, getting more out of the existing system. When you have this balkanized operation, you tend to be conservative in how you operate the system, whereas having it centrally operated frees up a lot of that capacity. There is also better planning, better risk mitigation, and certainly long term benefits from investment, where if you have real transparency and clear, accurate price signals on where the constraints are, you can make better decisions on investment.

CO_2's a big issue for California. And our studies showed that when you look out at 2020, and even in the 2030 simulations, you're seeing a steady decline in CO2, well below California's target of getting to 40 percent 1990 levels by 2030. So the regional market actually helps further reduce CO2 emissions in the 2030 simulations.

So that's it. I'll just wrap up there. As far as where we're at in the process, we're getting comments on our study. We're going to post a final report. It'll actually probably be posted around the end of June. And we're targeting a workshop in mid-July with the California agencies to review both the study results and possible proposals for a regional governance for the ISO. And I did include in the slide some reference material if you wanted to access the specific studies. So that's it. I look forward to any questions you might have.

Question: If you could go to page number nine, or slide number nine. That was the one on the benefits, cost savings. Could you clarify, do those numbers, did they impute a cost of new transmission and net out the cost of new transmission to get those savings numbers?

Speaker 2: That's a really good question. The only significant new transmission was in that last column which we call the Regional Scenario 1A vs. 3, where we model this part of the RPS portfolio for California, and access the high quality Wyoming, New Mexico wind that didn't require some transmission investment to get access to it. So the value you're seeing there is the net benefit. So it's the benefit of the lower procurement cost of accessing that high quality wind, less the cost of the transmission needed to get it.

Question: Speaker 2, on one of your slides you mentioned just briefly energy storage, but didn't talk about it that much. I'm wondering if energy storage plays a role in any of these assessments, either grid scale or distributed. Because I know that's been a big push in California.

Speaker 2: That's a great question. You know, one of the things that we really tried to be careful of is when we did this analysis we wanted to make sure we incorporated everything else California is doing to help with integration. So the study assumptions incorporated all the commitments on storage that California's already made. We've committed to 1300 megawatts of new storage in California. The model also, in choosing these optimal portfolios, could also choose storage to help with the integration, so in some scenarios we're actually seeing some battery storage getting picked up to supplement the solar in the model. Not a lot of it. It turns out that in many cases, especially with the declining cost of solar it was just cheaper to curtail it then to build storage to store it. So we did try to incorporate storage. We also tried to incorporate the impact of five million electric vehicles charging in 2030, under time of use rates that have would have workplace charging to help with the duck curve. So those are just some examples. There's a lot of other assumptions in the simulation to capture the other stuff California can do to integrate renewables.

Question: Speaker 2, on slide 11 you talked about California's CO2 emissions. Did you take a look at WECC-wide CO2 emissions? And in that context did you think about the Clean Power Plan, and what individual states would do, and whether, even if they went their own separate ways, having an energy imbalance market or region wide dispatch would impact that?

Speaker 2: We did look at WECC-wide emissions, and we saw a similar trend to what you're seeing here for California emissions. WECC-wide emissions are going down. In 2030 you have a lot of coal retirements happening throughout the West that are driving that down. So that, plus the additional renewables… The base scenarios did not model CPP compliance, but we did run some sensitivity scenarios where we imposed a WECC-wide carbon price and were able to get to CPP compliance on a mass basis for the entire WECC region. So we have that analysis as well.

Speaker 3.
This is an important topic to MISO generally and to me personally. So I'm really glad to be here to talk about it. Those who were hoping for some in depth discussion of PJM Miso market to market are going to have to wait a little bit longer, because I'm not going to really talk about it either. I want to talk a little bit more philosophically about some of the challenges with seams coordination and where we've been and where we're going.

So, MISO is a geographically large RTO, ranging from Canada all the way down to the Gulf of Mexico. As we have consolidated dozens of balancing authorities, we've had the opportunity to drive efficiencies for customers through centralized dispatch and regional transmission planning. But our location and our geographical scope also bring some interesting challenges when we think about seams coordination and coordinating with our neighbors. We share borders with a diverse set of entities, with different business models, different objectives, just different views on how things should work. We share borders with two RTOs, PJM and the Southwest Power Pool; with two investor owned utilities, Southern Company and Louisville Gas and Electric; with a federally owned entity, TVA; with two muni co-ops, Associated Electric and Minnkota; and with I'll call it two and a half Canadian entities, AESO and Saskatchewan and then we have the hybrid of Manitoba Hydro, which is both a member of ISO, but also a seams partner, due to their location in a different country.

So that wide variety of neighbors introduces some interesting challenges as we think about moving seams forward. Why is it important? From the MISO perspective we see seams processes really as key in making sure that we're providing reliable least-cost energy to customers. So when we think about principles for seams, there's reliability--let's keep the lights on. There's efficiency--let's make the best use of our existing assets and our new assets to drive lower cost for customers, and there's equity--let's make sure, as we try to bridge the differences between them, that we're doing it in a fair way, so that we've got some appropriate treatment of the cost impacts and the dollar flows, if you will.

This question of seams coordination is going to be important going forward, right? The Eastern Interconnect is seeing (though not nearly on the same scale that Speaker 2 talked about) significant changes to our generation portfolio. We're seeing a lot of retirements of coal and also nuclear, driven not just by policy, but also just by the market fundamentals. We're seeing a lot of new resources come online, particularly wind in our area of the footprint, but increasingly things like solar, as well, all of which is going to change the usage of the transmission system. It's going to drive the need for new investments, and the best thing we can do for customers collectively is reduce that overall cost by making the best use of the assets that are still going to be there and trying to minimize whatever the costs are for new investment going forward.

There's a tie to Order 1000, too. So, Order 1000 is really focused on the transmission planning aspects of regional coordination, but planning and operations are inextricably linked. When we think about how we plan and we share costs based on expected benefits, it's really in the operation of the system that we maximize those benefits and get the value. And we need to think about tighter integration between those things.

As we think about how the industry has evolved over time there are a few things that I think are important or that strike me. First, from a MISO perspective, and from a seams perspective, really the landmark and still the model to follow from our perspective is the joint operating agreement and coordination that we have with PJM. Certainly we have things that we continue to work on, to continue to refine those processes and meet those seams goals, but we've taken some major steps forward from the original joint operating agreement to in 2015, when we started the market to market processes and addressing not just the maximization of efficiency, but also the equity issues around the dollar flows, from the settlement requirements and procedures that are part of the market to market. When we look forward, things like parallel flow visualization are important, but the thing I would note on this chart which will be a little bit of a theme in my upcoming remarks is that the road to parallel flow visualization started in 2006, really, with a FERC order to get together and work on some of these problems. NERC set the project in 2009, and the current target go live date is 2017. So that's a long road to get there.

The other thing I would note with respect to my chart on MISO's current seams procedures is that the stuff on the top is primarily the FERC driven activity. And so what I would note is that often it has taken FERC intervention or leadership in helping the industry move forward as a whole, to help us reconcile very real differences that we have as we think about how the system should be operated. Simplistically, you know, the challenge has to do with the mashing up of a network transmission view with a point to point view, but even within that, there are many different perspectives on how to approach things.

So the way we work on seams coordination with our neighbors is largely through bilateral agreements with each of our neighbors for a number of functions. So while our goal would be to have consistency, the reality is that because of our differences there are real reasons that we have differences in how we address many aspects of seams coordination with all of our neighbors. Even in the case where you seemingly have agreement…an example of this might be the market to market seams procedures which we now have with both PJM and SPP. On its surface, that would seem to be aligned and similar, but the reality is that different objectives and philosophies that SPP holds, which I might describe as being a little more of a hybrid network service, point to point service model, are driving how we actually operate those systems in different directions. So on the surface, you might think there's agreement between the two systems, but it's not that simple, and it introduces a lot of complexity into this process, which really has the ultimate result of having inefficiencies that don't allow customers to capture the benefits that we could provide from a more efficient use of our resources.

So this is my picture of what it feels like to be MISO working on a seams issue [a man being pulled in all directions]. Because really we're working on one off agreements with everybody, but the reality is that anybody in the Eastern Interconnect that's working on a seams coordination issue has probably felt this way at one time or another. My best example of this (it's a trivial example in some ways, but it really left me thinking that surely there's a better way to move this forward) is a group called the Congestion Management Process Council. It's a group that has to come to agreement on changes to our congestion management protocol. And we were working on some changes towards the end of last year, and they were fairly complicated, and you had four or five different perspectives represented that you were trying to consolidate. But what really struck me about the process was the day that we spent literally an hour trying to approve the minutes that reflected the agreement that we had notionally come to the week before. This is complicated stuff to move forward because of all these different perspectives.

We're optimistic about Parallel Flow Visualization. Parallel Flow Visualization is, as I noted, a long running effort to bring more real time information about flows on the Eastern Interconnection, to provide more transparency and information. An analogy (perhaps not perfect) is it's a little bit like moving from using a gas station map for directions to using Google Maps. At least you know kind of where you are at any given time. And so we think this is an important step forward, and we need to keep pushing forward and not allow for further delays, because it's taking us a long time to get there and, frankly, even as we arrive at this endpoint in 2017, it's still not equal to what, for example, MISO and PJM have been doing since 2004 or 2005.

So technology has moved faster. Market rules have moved faster. All of that is moving faster than we're able to move our actual seams coordination processes forward today.

So the overall goal from MISO's perspective is the "seamless seam". The joint and common market was the notion for MISO and PJM that was really focused on making sure we have an efficient dispatch and making it fit for customers. Their benefits and how they saw the benefits of the usage of that transmission system should be largely disconnected from what RTO their utility was a member of. And we continued, with PJM, really under the guise of the joint and common market, to move forward with new enhancements and protocols to continue to make things better.

I think from our perspective the question is, how can we do that even more across the whole Eastern interconnect? Parallel flow visualization is a part of it. Continuing to invest in tools is part of it. More standardized seams processes are probably part of it. Trying to reconcile this difference between the network and point to point views is part of it. So there's a lot of work in front of us, and I look forward to the discussion this afternoon about how we can try to move some of these things forward, because this is a complicated issue, but given where we are with our changing resource mix and the level of investment that the electric industry faces, I think it's more critical than ever that we take this goal on.

Speaker 4.
Thank you. I'm kind of the odd man out today, it feels like. I'm going to give you a little different perspective. I'm calling it a "bilateral market perspective." Some would call it a non-market perspective. I've been called a disorganized market before. [LAUGHTER] But I'm going to stay with the bilateral market perspective today. In this, I'm going to take a little different approach from the other speakers, but I think you may hear some common themes from what you heard from my three other peers up here today.

On top of a bilateral market perspective, you're going to get the Southern Company view of life. So this is the Southern Company philosophy on how we do our business, and it's all centered around the customer. Our focus is around creating high reliability and maintaining low prices, and we feel like that creates value for our customers, and so we get high customer satisfaction, and then the rest of this circle takes care of itself. So every decision we make is based on the folks in the middle of this circle (the customers). So the guy that's footing the bill is the one I'm trying to make happy. So when you what appear to be some strange decisions coming out of Southern Company, if you back up far enough, you're going to see a customer somewhere in that decision. So I just wanted to put that out there to give a little background on where we're coming from.

I want to talk a little bit about bilateral markets, and how we see them. So the key objective is providing long term sustained value to customers. And we really do that by taking the long term view of everything we do. So when it comes to resources, we're looking for firm resources for the long term, and firm delivery out of those resources under various conditions. So any resource procurement has that as part of the equation. And we're planning for very limited congestion. So I've got Katherine Prewitt with me today. We're planning for really no congestion, and that's where we want to end up. Some of that comes from the Integrated Resource Plan that we do. When we're evaluating generation resources, we optimize both the procurement of the generation resources and the impact on the transmission system and how it integrates with the other resources in the grid. So we take that into account.

What we're really after here is long term predictability, both from a cost, availability, and reliability perspective and even in terms of having the fuel diversity to give us those multiple arrows and the quiver, so that, depending on where fuel prices go, we're hedged against any one fuel putting us in a bad position.

Turning to real time operations in the bilateral market, we have economic dispatch of our entire fleet. Southern Company covers four states, and we're dispatching that whole set of units as one fleet. It's unit commitment based on unit costs, adjusted for expected constraints. Sounds a little bit like security constrained economic dispatch. So sounds familiar, doesn't it? And if there's congestion, and I bet my other friends up here would say the same thing, we are typically going to manage with the most responsive resources. So I think all of us, when you get to real time operations, we look very similar. Visibility and predictability is what gets you to a successful end. So the more visibility I have of both the transmission system and all the resources and the more predictability there is in terms of how those things are going to behave, the better I can manage reliability, and that's, in a lot of ways, how I measure success.

With respect to seams management, an approach like the oncoming Parallel Flow Visualization, which Speaker 3 mentioned, is going to provide some value. We're going to get higher accuracy out of that. We're going to get more visibility out of that. We'll get more granularity, and that should give us more predictability, if we know where we're at on the Google Map as opposed to the map out of the gas station. One word of caution here, is there's always the concept of maximum utilization. That you shouldn't leave any capacity on the table. That you shouldn't leave a dollar on the table. I'm an operator, so I'm conservative by nature. We are going through a pretty dramatic change in the industry. So especially with what Speaker 2 has talked about…we haven't seen quite the same level of change in resources, but it's coming. And we're headed into a time of increased uncertainty in how the system is going to perform from a reliability standpoint. And my only word of caution here is, let's don't stretch to the last megawatt or the last dollar and put ourselves in an untenable situation from a reliability standpoint. It's OK to have a little bit of margin for error and have the lights stay on.

My last bullet here mentions the coexistence of bilateral and organized markets. I've got a new neighbor as an organized market, and we spent a lot of quality time together recently, but we came to a good conclusion by working together, and the biggest part of the challenge of that discussion was that we would say the same words and mean totally different things. We had a communication gap. I think that in a lot of cases, we weren't as far apart as we thought we were, but it took us a long time to realize we weren't that far apart, and that our perspectives were not necessarily a dramatically different as we thought. But it did take a lot of work to get to a point that I think is working for us quite well right now.

So, some things to consider. Visibility and predictability from an operator's standpoint are key ingredients of both reliability and economics. I think visibility and predictability are important in both regards.

I do think one size fits all solutions are going to be a struggle, and I don't believe those are the answer. I know there's value in consistency. There's such a diverse set of interest across the industry, but I do think we've got to take regional differences into account.

I think one place for us to start if we really want to put some effort into moving forward with more coordination around seams, is let's find the areas where we've got some pretty good commonality already and start from there. And I would say day ahead coordination might be a good place to start, around some coordinated unit commitment plans. I said earlier that when it gets into real time, we're not that much different. We've got some different tools. We've got some different ways of managing the system, but our perspective on reliability is pretty much the same. Day ahead coordination is one place that's pretty close to real time where I think there might be some opportunity. With some good coordination (not that there's not coordination going on today) I think there's an opportunity for improvement. I think you can increase your visibility of what's going on. Increase your ability to anticipate what's going to happen in the near term. And I really think the proper forum is that voluntary industry initiated forum, outside the regulatory environment. Now, where would we find that forum? Maybe it's the North American Transmission forum. Maybe it's some other forum that's not in the regulatory environment, because I think you're going to have the opportunity to have a more candid discussion in that non-regulatory environment.

General Discussion.

Question 1: Over the last 20 some years, we've moved from transmission planning at the state level to transmission planning in some parts of the country, not everywhere, but some parts of the country, at the regional level through RTOs. Should we move to transmission planning at a higher level than the RTO, and if we do move to a higher level than the RTO, who would that be?

Respondent 1: Well you know, obviously we have a process under Order 1000 for inter-regional planning coordination. In case of the West, we've just implemented that process this year, so we're really having our first pass of how it works. I would say so far, so good, in terms of getting alignment around the various planning regions in the West on some potential projects we ought to look at in our respective planning processes. So I think there will be a good opportunity to do that kind of joint planning study. I think that's the easy part right?

The real challenge is if you see something and it has potential, how do you move forward on it? How do you get alignment around who's going to pay for what? And even with Order 1000 in a regional process, we still have some big barriers to overcoming these cost allocation issues. And I think one of the benefits of a broader ISO/RTO is that you internalize all of that, you have an established framework for cost allocation among your members, and, at least in the case of California and the West, we think this regional market is going to provide better opportunities for these kinds of inter-regional transmission projects. We need to access the high quality renewables that are out there in the West.

Respondent 2: I think you've got to be careful about this, or you're just trading one set of problems for another. We've got over 1,000 processes in place. We've got pretty good planning processes. You go larger than an RTO—say we go to a federal, national planner—it just seems like you're losing perspective. You get that high of a level, and I think we've totally lost focus on the customer and the guy paying the bills. So I just think going at a higher level than what we've gotten already is getting pretty darn big.

Respondent 3: Well in general I think a broader perspective is a good thing. I understand the basis for the question is whether or not broader would be better. But I think there's probably a balance to be struck. I agree with what Respondent 2 said as far as keeping the local needs in perspective, because even with the RTO planning processes we have today, we have to integrate what's being done at the transmission owner level, what I'll refer to as the local level. So it seems, just from a practicality standpoint, much more difficult to do that if you'll be looking at this on an interconnection-wide level. You know, incorporating all the local needs and everything, there seems to be a practicality concern to that. And certainly I think that between even just PJM and MISO, we've seen the impacts of regional differences from the standpoint of the desires of even the state regulatory agencies in our footprints, and all that sort of thing, when it comes to transmission planning. And then, of course, I agree that the big elephant in the room is always cost allocation. We see that even inside the RTO planning process we have today. So I think there'd be significant challenges to that, and I think that from a cost benefit standpoint, there's probably a balance to be struck as far as getting broad enough to be really beneficial, but not so broad that it becomes impractical.

Respondent 4: I would echo that about the practicalities. So the interregional connection is important between the RTOs and between the RTOs and their our non-RTO neighbors. But it is challenging, and it is largely driven by the cost allocation questions, which are tied back to some of the different philosophies about why we're planning and what the benefits of those plans are. I'm of mixed mind about broadening this, because from just a pure theoretical perspective, I think about this resource mix change we're going through. There's probably an economic answer that looks something like MISO and SPP delivering wind to, you know, New York and New England, but the practical reality of that is that you're not going to expect to get to a good outcome. Because you have all these other factors that come in to play around local needs, local differences, different views on cost allocations. So it feels impractical at this time to me.

Question 2: Speaker 2, your studies on this Western regional build out and the cost savings and effects on distributing renewables, how much does it actually depend on new long distance interstate transmission to do that? The discussion we just had was more on planning and cost allocation. This is more on actually building it, because if the states need to approve those siting permits, any build out is going to require you to build transmission or be a part of building transmission with other states. So I guess my question is narrow in the sense of, how did that play into the assumptions in the report? But my question is also broader with respect to these interregional connections. It's not just the planning, but also the building, and how we get there?

Respondent 1: That's a great question. Essentially, we looked at two regional scenarios in the 2030 cases. You see them there on the far right, on that bar chart. The first is kind of what we're calling our non-regional case, so in all these scenarios we build out a renewable portfolio to get to 50 percent. The non-regional case 1A is fairly California centric. It has some out of state resources, but it can be achieved without any new major transmission, OK? And then scenario two is very similar to that. The portfolio is very similar. It's very California centric. It has some out of state resources. No major new transmission. So you're seeing that even with a similar renewable portfolio going to the regional market, it provides a billion dollars in benefits to California. And a big part of that, the majority of it, is this avoided curtailment issue. By virtue of eliminating the barriers to sinking surplus power throughout the West, you're able to achieve the 50 percent goal in California by building purer renewables. So there's a big benefit to this regional market, even if you don't have to build a lot of transmission.

Now, scenario three was really this scenario that involved a more West-wide procurement to meet the California RPS, and it did require some major transmission. We didn't pick specific projects, but we picked some proxy projects to access the Wyoming, New Mexico wind. And so you can see there's a bigger benefit there, but that benefit is net of the cost of that additional transmission. And a lot of people challenged us and said, "Well, why do you need this regional market to build transmission? We could build it in a regional project today. We have Order 1000 and a regional planning process." And, you know, again, to reiterate my point, the interregional Order 1000's great for collaboration, but getting projects over the finish line is still a huge hurdle. And we think the best prospect of building these kinds of transmission projects is to have a broader, regional footprint where you're internalizing that cost among your members. So that's not to say you still don't have cost allocation issues within your participating members, but you have a more formal framework for how you're going to evaluate who shares what cost than you do with two different regions trying to negotiate. So I hope that answers your question there.

Question 3: This is a question for Speaker 2. On page six of your slides, you sort of outline what you had mentioned earlier--that the legislature in California had acknowledged the benefits of a regional market. At the risk of sounding cynical, though, it seems to me the laundry list of impacts you are supposed to study really consist of a bunch of poison pills, that would prevent, and I, how do you, and maybe Brattle can thread that needle in their studies, but…

Respondent 1: Yeah. I mean, they threw everything and the kitchen sink in there for us to look at. So I think it's safe to say that while, on the one hand, they can appreciate that there are benefits to this regional market, there's a lot of skepticism about what that would mean in terms of relinquishing governance control. A big concern of course is, with the California ISO, if it became a regional organization, would it still give the same kinds of deference and support to California environmental policies? That's really the big, the big rub with the Legislature. And would they have the ability to influence and really push ISO to help enable some of these policies? So there is a very legitimate concern around that. So they gave us a high hurdle to look at all these things. But I can tell you, the analysis looks at every one of them. And I think we have a solid case to answer affirmatively that in all of the listed impacts, one through six, we can show very significant positive impacts. You know, we'll have our critics out there that will argue the contrary, but overall, I think if people look at this from an objective lens, it's really a win-win for California. And if the ultimate goal is to have meaningful impact on GHG emissions, not just in California, but throughout the West, this regional market platform is a far better platform to do it then California being an island isolating itself from the rest of the West.

Question 4: Thank you. This is a general question. It's about how you do this interregional seams planning when there are so many other changes going on in the system. And just by way of example, on slide 12 of Speaker 1 presentation there's the Duff Rockport Coleman line. And I think that that line was necessitated by the retirement of a generator at Coleman, which caused congestion problems in MISO, at least on the MISO side of that. Which is driven by the need to serve a smelter in that area. Well, the smelter has just announced that it's retiring. And so now maybe the line's not required at all, but yet you've got a seven million dollar project which you're going to put out for RFP. And now it's got everybody approved and everybody's very excited, and I'm wondering whether the ISOs have an ability to go back and look at those kinds of projects.

And I think it's a generalizable problem, in that when we look at the huge changes that have taken place and are taking place in the PJM market, with Marcellus Gas and changes in flows… PJM did cancel a huge transmission project. But there's still a lot of transmission getting planned and built to get power, say, out of Illinois, further East to deal with transmission constraints in that area, which would be completely different if nuclear plants in that area retire, plants that haven't cleared in the capacity auction and the owner says they're going to retire. So you've got this issue of long term planning between generation and transmission, and I think there's a lot of incentives to just build transmission and get it done, as if that's the objective. I'm just wondering how the ISOs balance that issue around generation versus transmission and long term planning when so much is changing over these timeframes.

Respondent 1(): Some of the answer is that's why there's not a lot of inter-regional transmission, because from the MISO perspective we're really looking for that robust business case, looking at a number of scenarios, a number of different outcomes, because, at least from the MISO perspective, it's very rare, once a project is approved, that it comes off the books.

The best example we have of that is we had a planned project that was no longer needed when the economy tanked and there was low growth and Detroit went down. But apart from that, there are very few examples, and that's tied to the fact that we spend a lot of diligence up front trying to plan for uncertainty. And the reality is that there's a lot of uncertainty now. But to some degree there's always uncertainty, and your transmission assets are really longed lived. So it's really about looking at as many scenarios as you can and making sure you have a robust business case. And so that's why I think we see, when we talk about this inter-regional between MISO and PJM and why there aren't more projects, that part of the reason is that there are some uncertainties that you can't resolve. There are some changes. There are, you know, lower gas prices. There are a lot of reasons that say, “Oh, maybe we should just hold off.”

Respondent 2: Just a follow up on that. If you do approve a project, like this one is approved, and then you find out that the smelter retired or is planning to retire, do you go back and then say, “Hey, wait a minute. We should take another look at the project to see if it’s still needed or not, given that we built it or we justified it based on the need to serve load, based on the smelter?”

Respondent 1: At least in the case of this project, when we were looking at various scenarios, they included questions around what the smelter would do. So I don’t know what the exact scenario was, but from that perspective we would say, no, it’s done. There were questions about the smelter even at the time, so that we think we’ve made the robust business case under a number of scenarios and it should proceed.

Respondent 3: Just a couple thoughts from the PJM perspective. Certainly, as Respondent 1 describes, I think the planning process needs to be dynamic, and you highlighted some perfect examples of the dynamic nature of the planning process. We actually canceled more than one major backbone project. There was PATH (the Potomac Appalachian Transmission Highline) also MAPP (the Mid Atlantic Power Pathway). And so it has to be dynamic.

And with this specific project, even if the MISO-needed work were to go away (and it sounds from what Respondent 1 is saying that it hasn’t), on the PJM side we still have this Rockport special protection scheme which is a suboptimal approach that we would like to move past, and this project allows us to do that. So even from the PJM side we would still have the need that we used to establish the project in the first place.

The last point I’ll make is that the other driver of transmission planning for PJM is the market efficiency analysis. So given some of the changes that we’re seeing on the system--you know, the fuel mix changes that we’re seeing, the new generation locating in really beneficial areas of the system. We’re see a lot fewer reliability projects coming out of the RTEP process in PJM. And I think as a result we’re seeing more of the market efficiency projects now being included in the plan. That’s because I think the reliability projects used to take care of the market efficiency needs when they were being planned, and when we see less reliability planning, we see more now of the market efficiency upgrades. But that market efficiency process includes a cost benefit threshold. Such that, I think, for exactly the kind of uncertainty that you’re describing, we make sure that there is a sufficient threshold of cost benefit that’s achieved before we’ll actually put a market efficiency project in the plan. And so there are components of the plan that recognize that uncertainty exists and try to deal with it in the best way possible.

Question 5: I have a slightly long clarifying question because of the point that some of the speakers made about using the same words to mean different things, and so I’m not sure what people are talking about. And so that confuses me. And this is normal in this process. And then I have a policy question.

Let me tell you first where I’m going with the policy question, and then I’ll ask the clarifying question.

In coordinating all these issues across the operations of the grid, there are at least two problems that constantly worry me about this. The first and most important one is the incentive effects of what you’re doing. So, are you providing incentives for people to do things which are economically inefficient or to forego opportunities that are economically efficient because the way that you're pricing and compensating people and setting rules either forces them to do something that's uneconomic or they can't do something that's economic, and all the other kinds of things that went with it? And these are reasonable questions in both the bilateral and the RTO contexts.

Then there's the second set of issues which we've spent a lot of time in the past talking about which didn't come up this morning. Maybe nobody wants to talk about this, but this is the open access nondiscrimination point of view.

So if the answer to the first question about whether are some incentive effects is yes, then we're doing something that's different than the economically efficient solution, and if we want to stop people from exploiting those incentives, then we have to have some rules, and rules tend to be discriminatory, and now the system is not meeting the standards of open access and nondiscrimination, despite the fact that FERC will often avert its eyes from these problems because they're too politically difficult. But that doesn't mean the problem isn't there. We don't want to still worry about it, particularly going forward, given all the changes that are taking place in the system, and that we want to get innovation in this market. So I'm worried about both problems, which is the incentives to do things which are uneconomic, and, secondly, to what extent is this compatible with open axis and nondiscrimination which I think are necessary for a lot of other reasons. So that's the policy issue.

Now I'll step back to the clarifying question, if I can. I heard several terms used here, and I think I can explain some of them, but I'm not sure, and some of them I'm not sure what's the difference. This is all about characterizing the dispatch. So at one end of the spectrum we have the single economic dispatch--security constrained economic dispatch. We might think about that as what goes on inside ERCOT. OK? So it's not connected very much to anything else, and it's just there. And that's one end of the spectrum. And next is "joint and common dispatch" which I heard, and I interpret that to mean that PJM and MISO have a conversation with each other and they keep re-dispatching their plants until they get to a pretty good approximation of the first answer. So they're reflecting the constraints and the situations, they're definitely communicating, and they're doing it jointly, but they have separate dispatches. There's a little inconsistency, because you can't do that perfectly, but you're trying to get as close as you can to the single dispatch. If I'm wrong about that definition, I'd like to be corrected.

The next one was "market to market," and I didn't know what that meant. Then the next phrase was "point to point." I think I know what that means. I would interpret it as identifying the point of injection and the point of withdrawal. We have parallel paths along the way. We need transparency to see what the parallel flows are all going to be, and then we're going to do something. And I don't know what the something is, but I can see the advantages of having that information. And then the last term, which was also on one of the charts, was "contract path." We know what that is from, we were actually trying that, using a contract path as the scheduling mechanism for controlling what's going on, and that's what gave rise to the need for transmission loading relief because contract path is fundamentally inconsistent with the operation of the system. And so you have to have something else, and these other things are all examples of the something else.

So I don't understand what the distinction is between "joint and common" and "market to market," and I don't understand exactly when you have "point to point," how you deal with the associated incentives, and are there inefficiencies, and then how does this affect both the performance and the open access nondiscrimination characteristics. So that's my first question. [LAUGHTER]

Respondent 1: The way I use the term "market to market" and the market to market congestion management process and the "joint and common" dispatch process is as being synonymous. So I think those two are the same thing from my perspective.

Respondent 2: I would agree. Market to market is how we accomplish the goals of what you described as the joint common market.

Respondent 1: That's what I call it. As far as the real time dispatch process, I would go as far as even saying our day ahead coordination approach is that as well, because we operate for each other's constraints and the day ahead market as well. We've actually moved toward sharing entitlements now in the day ahead market, which is yet another level of detail, but the point is, that joint and common market, that joint and common operation, that joint and common dispatch is the market to market congestion management process. I'm not sure how I would differentiate "point to point" and "contract path," because frankly I think of those two things as being synonymous as well. But maybe I'll look to the other end of the table to see if they have a thought on that.

Respondent 3: I would agree. I think they're one and the same.

Respondent 4: It was a clarifying question, but the transmission loading relief arose to get the parallel flows that were associated with the contract paths so that we could then understand what actually happened as opposed to what was going along the contract paths. So, I mean, they are different.

Respondent 2: So maybe one way you get contract path is by procuring point to point transmission service. Would that be the distinction?

Respondent 4: Well, logically, it went the other way. I mean, back in the day, when I was first involved in these kind of deals, people were scheduling according to the contract path. And then immediately NERC invented the transmission loading relief system because you overloaded the system. You know that with the contract path story.

Respondent 3: Well, I mean, certainly we're still scheduling based on contract path between regions. The transmission loading relief just gives you a mechanism to address it if you have a problem. I think you've got to back up a few steps, though, as you talk about contract path and the fact that certainly the electrons don't know about the contract path. They're going to flow wherever God tells them to flow. But in your long range plans, at least from my perspective you're accounting for that. So I know I've got firm arrangements on certain contract paths. So I accommodate that in my long range plan, and my neighbors know that as well. So any loop flows or parallel flows are accounted for in long range planning, as you've got firm contract paths accounted for. I don't know if that helps any, but I do think it's more than just a real time issue. It's got to be factored in if you've got firm arrangements that you're dealing with from a contract path standpoint.

Questioner: That's helpful, and so for the sake of this discussion I would merge the "joint and common" and "market to market," because you admitted it's the same thing, which is good, because I didn't understand the difference. And then the "point to point" and "contract path" have been defined just now as essentially the same thing, although we could have an argument about that, but let's don't.

So now we have these two ways of dealing with it. Now, these two ways each have incentive effects in terms of the prices that occur that people see in the markets versus the economic costs at the margin. So to what extent are the two different approaches confronting these incentive effects, or are they serious? Are they not? Do we have people trying to arbitrage this? And we know about lots of examples of these situations, particularly at the borders in California, where these things don't match, and people have an incentive to go do something, and so, how serious is that problem?

And then the second question is, if you're worried about long term innovation here and the entry into the market, do you want to limit open access and nondiscrimination? Requiring these is FERC's official policy under Order 888 and subsequently, but in practice a lot of these things we sort of avert our eyes, but I think those are serious questions. So are there incentive effects that are different for these two different approaches, and are there discrimination issues that are different under these two different approaches, and do they matter? Or is it just that I'm a worrywart?

Respondent 1: I'll certainly chime in on the incentive effects, because the more you can internalize loop flow impacts by broadening the reach of the markets, the less of these parallel flow issues that you have. But to the extent that we have markets operating side by side with non-markets or even side by side with other markets, these parallel flow issues do exist, just like the loop flow effects do exist. And I do think they create incentive impacts. So we still have contract paths, reservation and scheduling between areas, between market and nonmarket alike. And it is necessary to price those contract path energy transactions between those areas. And to the extent that the contract path mechanism still exists between these areas, it does create incentive effects to try to get around limitations or take advantage of the way that pricing is done by different regions. So, for example, we saw issues a couple of years ago with entities scheduling New York through Ontario, through MISO to get to PJM. Because they got beneficial pricing from New York because they were seen as exporting to Ontario, even though the energy flow was going New York to PJM. And, you know, I think FERC has addressed that, and it's mostly behind us, at least that specific example. I know my market monitor's still concerned with folks still doing that even on the paths that New York has banned, because they split their transactions up. And they schedule New York to Ontario and then do a separate transaction, Ontario through MISO to PJM. So in their opinion it's still occurring. So that's the kind of incentive effect I think you're talking about, where you have this simultaneous existence of the market constructs and then also the contract path between market and nonmarket areas alike, and it's something where we're looking at whether or not we should be implementing rules that would eliminate the ability for market participants to inappropriately take advantage of those incentive effects, because it results in energy flows that are inconsistent with the way the pricing is being done. So I think my answer is, yes, incentive effects still exist. And I still think there are going to be more efforts necessary in order to make sure that they are appropriately accounted for.

Question 6: This is a question for Speaker 2, and it goes to the mentioning a couple times of Wyoming wind being used to serve California load, and I'm just very curious about that, because I had looked at that several months ago, and it didn't seem to make sense for a couple reasons. The first is that the cost of transmission alone is around 30 dollars a megawatt hour, it seems, for something like TransWest Express. And when you have solar available to California delivered at less than $40, and with expectations of lower prices, it's hard to see how transmission of 30 dollars plus the wind itself could beat solar delivered to California. And I understand the idea that perhaps there's some diversity of supply for wind in many instances, but Wyoming wind seems to be somewhat unique in that it peaks at about five to six p.m. Pacific Time, so it's hard to see why it wouldn't simply contribute to the duck curve problem in just simply in the way having just more solar would as well. So I'm just wondering, with those elements, if you could just sort of walk through at a conceptual level how Wyoming wind would make sense for 2030. Thanks.

Respondent 1: When we looked at this, we used a consulting firm that developed an optimized portfolio model that would look at, given the output profiles and capacity factors of these resources, what would be the least cost mix, including the cost of curtailment, to meet the 50 percent RPS. So the Wyoming and New Mexico wind does have a very different and complimentary output profile. You may be right about the timing on the peak, but you have to remember that a duck curve is predominately a spring season phenomenon, when the loads are low. That's when we get really the oversupply challenges, but when you're looking at meeting the RPS goal over the course of the entire year, what the analysis has shown is that both the Wyoming, New Mexico wind have very similar and complimentary output profiles. And the big issue with solar, of course, is that as you get higher and higher levels of it the curtailment of solar goes up in a nonlinear fashion. So using solar to meet the RPS becomes less and less economic when you look at their curtailment issues.

With respect to the transmission costs that you mentioned, I don't even know if they've come up with a levelized cost of transmission assumed in their analysis, but the number you used sounds high. I don't think it was quite that high. In the model we weren't building transmission directly to California. It was transmission just to get the Wyoming wind onto the bulk power system, as opposed to bringing it all the way to the California border. So I don't think the costs were as high as you mentioned. So I can get you more details, and there are a lot of details in the material we presented a couple weeks ago on the wind profiles for the Wyoming, New Mexico wind as well as the cost assumptions. But the model optimally picked that wind when it was made available, under that scenario three, in lieu of California solar, even factoring in the cost of the transmission. And, like I said, I can follow up with you with all the cost details that went into that.

Question 7: I have a process question. Speaker 3, in your presentation you talked about technology and market rules sort of outpacing the process for working through seams issues. But Speaker 4 talked about taking this outside of a regulatory context and into more of an industry driven process, and I'm wondering if people have ideas about how to streamline that industry driven process, so that it is able to be done in a more efficient manner that doesn't get itself outpaced with the concerns that you addressed? And also, as part of that process question, are we focusing on the right things in these various processes, as opposed to sort of the low hanging fruit, the most bang for the buck? And I'd just be interested in the panelists' thought on those questions.

Respondent 1: I think speed is not our strong suit, no matter what forum we're in. We're a slow moving bunch. So the last part of your question was about --

Questioner: I know there's often been talk over the seams issues of sort of low hanging fruit, and I'm wondering if the low hanging fruit is the most bang for the buck to address the inefficiencies and so forth, or if there's some other way to manage the stakeholder process so it is getting to the higher priority issues more efficiently.

Respondent 1: I don't have a good answer on what's the right forum to try and mange this. I mean I think it is an interconnect by interconnect issue. There may be different answers in different places. The West may do something different than the East, or have its own entity in and of itself. I do think the low hanging fruit may be something we need to address right now. As an operator, at the end of the day I'm primarily concerned about keeping the lights on. And I think all of the operators have that focus. Certainly economics is a component, but a big measure of success is, did the lights stay on? And with this change in resource mix that we've got coming, that's going to become more challenging if we're not operating in a coordinated manner. So I'll go back to what I had mentioned earlier. I think the low hanging fruit may be that we've all got a common need around a higher level of coordination as you get close to real time. That may be the place to start. I'm not sure what the forum is, but that may be the place to start to get the conversation going on a higher level of coordination. And then you can back up into other avenues that may create more benefits for you.

Respondent 2: Let me start with the caveat that, no, I don't think we've got a discriminatory issue here, but from MISO's perspective the reality is that as you try to line up the kind of market to market joint dispatch view with the point to point contract path view, you have a lot of risks of introducing inequities which can have efficiency impacts, and that also will have financial impacts around how you think about things like the relative firmness of flows and how you reconcile those items. And in fairness it's an issue about equity for both sides.

So the debate that MISO and Southern and others have been having for a while is ultimately about both sides saying, "This doesn't seem equitable from our perspective." So from the MISO perspective, those are the issues that are priority, and I'm not sure they're low hanging fruit. Because I tend to think of low hanging fruit as being the things that are relatively easy to address. Something like parallel flow visualization, I think, is low hanging fruit, right?

Around the transparency and awareness questions. I'm not sure I have a great idea for an answer, but two things that strike me. One, these things always get done faster with a deadline. The other thing is that given some of our existing forums, it may not work in the current set up. So, if you think about something like NAESB (the North American Energy Standards Board), I think the setup and the governance really reflects a world that doesn't exactly exist anymore. It's all kind of individual utilities, you know, coming together to try to solve these problems. And the reality is you now have a mix of RTOs and standalone utilities and different governance structures. So I think it's time to rethink some of those governance questions to help drive this forward and bridge the gaps and recognize that we really are a diverse industry. There's not an industry answer right now to how we do these things. There are differences.

Respondent 3(): With respect to the joint and common market between PJM and MISO, we had a joint common market stakeholder process that we had in place from probably 2003 or 2004 up through about 2009. That's when it went on hiatus for a little while, because things were working, and it was reinvigorated again in 2012 because we had some issues we needed to address. And since 2012, frankly, I think we've hit the low hanging fruit. We've significantly enhanced the FTR coordination and outage scheduling, and we've made transparency enhancements. We've done a lot since 2012 through that JCM (joint and common market) process.

But now we're into issues like, the market to market joint dispatch process has worked reasonably well since 2004, but we're basing entitlements on a 2004 freeze date. So it's 11 or 12 years old. There's probably a better way at this point. But that's a pretty fundamental redesign of what we had in place. And I certainly will agree with Respondent 2. It was much easier to get to the finish line by a date certain when you had a deadline you had to meet. Where we had, you know, day two market startup looming, April 1, 2005, or whatever it was. So we don't have that staring us in the face, and again, this is an extremely complex issue with various perspectives and various opinions coming together, and a wide range of stakeholders. So the Congestion Management Process Council is a lot of the Eastern Interconnection frankly trying to get together and come to an agreement as to how we should revise the process.

Respondent 2: Yes. And not even all the Eastern Interconnect, which is another piece of the problem, so it's a subgroup trying to solve the bigger problem.

Respondent 3: Right. So I'm not saying this is impossible. I think we are making progress. But I think it's reasonable to expect this is going to take a while, when the issues are as large and complex as they are, given the fact that I think in large part we've taken care of what the low hanging fruit are.

Respondent 4: Respondent 2, just to follow up you mentioned NAESB. I think you said it is time to rethink some of these governing structures. Have you got any specific ideas?

Respondent 3: I don't have a specific suggestion other than just that when we think about how the voting occurs in a lot of these structures, you're trying to resolve these issues where people have different standpoints. I think it's still heavily weighted toward a more utility based view, and so as you think about bringing some of these RTOs, or these aggregate positions, into the discussion, it becomes more complicated, and it's more complicated by the fact that, for example, on the RTOs, a lot of times the utilities are actually looking for the RTOs to represent their interests, rather than representing them directly. So I think that thinking some about how the voting and oversight of these occurs and trying to factor in some of the realities of having RTOs would be valuable.

Respondent 4: Well, voting weights--that should be easy to resolve.

Respondent 2: Yeah there's no problem, right? It's as easy as cost allocation.

Respondent 3(): Right. And along those lines, the last quick thing I'll mention is that, with respect to Parallel Flow Visualization, I think if it was just the visualization piece, it would be relatively easy. I think where the conversation went, though, is utilizing what we now have access to for information as to determining what is firm and what somebody needs to curtail when there's a transmission constraint. And that's where I think, really, the slowdown has occurred, because that's an equity issue. It's a financial issue on the part of the participants that are involved in the discussion, and that's where it gets extremely difficult.

Question 8: Sitting here as a regulator, I want to pick up both on something Speaker 4 said about it being better for this to happen outside the regulatory environment and then the recent comment about the need to rethink some of the governance structures. When I look at what's happening in my jurisdiction, a totally restructured state, I think we've got two divergent trends here very much. We've got transmission going more regional. For example, California looking to go outside California. Don't, we ultimately end up with something national? And all pretty much outside the realm and control of state regulators? And then the other direction in terms of generation is that things are going towards decentralized generation. More solar PV, lots of DR. Little people, individuals--nobody regulates putting stuff on the rooftop, et cetera.

And so I'm just wondering, is there going to be, in the future, particularly in restructured states, that regulators will be more and more limited to actually only overseeing the planning and the rate regulation of the distribution system? Is there going to be a role for state utility commissions as we rethink governance, as we figure out how to do things maybe outside the regulatory environment, and where the RTOs and the federal agencies, particularly FERC, are really making the decisions that impact the transmission and delivery of electricity?

Respondent 1: I guess I'll just say that from my perspective, I think the role of organizations like utility commissions is extremely important in how we think about these issues and getting input on these issues and making sure that the positions of the various state regulatory agencies are transparent and are known because I think they provide valuable, valuable input into the decisions that are made and the proposals that are vetted through the RTO stakeholder processes. So my answer is yes.

Questioner: I'd like some honest answers. Don't just be nice to us because we're here.

Respondent 1: That is an honest answer. [LAUGHTER]

Respondent 2: Politically honest. That's very good.

Respondent 3: I would just note, in the context of the governance proposals being considered in California with this new regional market, there's very clearly a strong interest and a lot of serious consideration about a role for a body of state regulators similar to what Speaker 1 described in this new regional governance model for the ISO in California. We're still kind of sorting through what that role would look like and what the scope of authority would be. But I really think that whenever regional governance proposal comes forward, there's going to be a formal role for the state commissions and the rest.

And the other thing we've been very clear on is that there is a very clear role for state policy. You saw my slide on all the California state policies that FERC or a regional alliance doesn't change. The state still has control and authority over RPS goals, emission goals, what it ultimately wants to do with fossil fuel resources. And it's really the job of the ISO to help enable those policies through our planning process, and so we've really tried to educate the state commissions, especially the California commission, that that doesn't change if the ISO becomes a regional ISO. We still have state policy transmission that we can put forward to support those goals. So there's always that tension, but I think in the case of what is being looked at in the West that the state commissions will have a very prominent role in that new governance structure.

Respondent 4: Just a clarification on my statement about "outside the regulatory arena." What I was really referring to there was a problem solving effort outside the regulatory arena, but not outside the purview, at the end of the day, of the regulators. And certainly, at least from the part of the country that I come from, I think the regional and the state influence on what we do is fairly important, because the regulators are responsible to the voters, who are also my customers, and so I think it is important to maintain, to the extent that it makes sense, that state regulatory engagement and approval authority on a lot of what we do.

Respondent 5: The MISO footprint is almost entirely still vertically integrated and state regulated, so some of these issues you raise aren't facing us in our part of the world.

Questioner: I guess a follow up question would be whether for a restructured state versus still vertically integrate states, some of these considerations are very different.

Question 9: When you look (in California) at the states that could come onboard at some point, you've got a variety of renewable energy standards. Obviously California is the most aggressive, but Arizona also has set asides, for example, not only for renewables, but particularly for DG renewables. And so the question is, have you thought through what the implications of these different renewable standards might be, particularly set asides for distributed generation?

Respondent 1: We have a number of parallel tracks in this regional effort. This study is a big track. The governance is another track. But a couple of other tracks are transmission cost allocation. We have a stakeholder process going on on that as well as on our resource adequacy. How do we ensure all these member states come on board, that they're not leaning on the ISO or vice versa, that we have some comparability there on resource adequacy requirements?

Transmission cost is, not surprisingly, a very contentious policy discussion. Our straw proposal is, I think, very consistent with what other RTOs have done, which is when new members come in, the cost of their existing facilities stays with them. So there's kind of a separation of existing facilities. And then going forward, to the extent that there are new transmission projects that can benefit both sub-regions, there's an assessment of what those benefits are, and at least a notional design that you would share in those benefits. You're sharing those costs commensurate with your benefits. That's very contentious.

California does have a much higher average transmission cost than PacifiCorp, for instance. And there's a feeling among some in California that California has invested a lot in its transmission, and that PacifiCorp's coming in and kind of free riding on getting access to that transmission without having to pay for it. Obviously, PacifiCorp has an entirely different view on that. So we're still in the process of sorting through that, but we're kind of holding the line on, no, there's not going to be sharing of existing transmission, keep that separate.

And the question is, for going forward transmission, what defines transmission that would be eligible for sharing between these sub-regions? So in the case of ISO and PacifiCorp, what projects would even qualify for the threshold question of, should they be shared? And we're really focusing on projects, obviously, that cross both footprints. Projects that are on the periphery of our regional footprint that both regions could potentially benefit from being another. And then projects over a certain voltage size was our straw proposal, so if it's over 300 KV, that that would be examined to see if it's providing benefits to other sub-regions within our footprint that might share the cost, even if the project is not physically located in their sub-region. So this is yet another challenge we're trying to work through, and we're really midway through that process.

Respondent 2: And let me add, because it was a great question and I speak from experience as a state in PJM, FERC Order 1000 introduced an effort to try to incentivize the construction of transmission lines driven, not by reliability or market efficiency, but driven by "public policy," which was a euphemism for mandatory RPS. And one of the biggest fights in our state organization was over who is going to pay for somebody else's mandatory RPS-driven transmission line? And we had 14 states in the discussion, and it was a very, very, very contentious disagreement over who's going to pay for a transmission line that is prompted by one or two states' mandatory RPS. And we ultimately resolved it by saying, you pay for your own. And that may have not been the intent behind the FERC Order 1000 provision, but it's what the states agreed to. So it's a very contentious issue when you start getting into who pays for these policy driven lines. Absolutely.

Respondent 3: We went a little different way than PJM in MISO. We have kept our focus, even in the realm of public policy, not so much on what the policy is and what the resources that are enabled are, but what are the quantifiable benefits that you get to the region from those, and we use that as a basis to allocate the cost. So in the case of MISO, it's renewable portfolio standards, clearly. We don't have a lot of solar, we don't have a lot of distributed generation. We've got wind, a lot of wind, but not all states had renewable portfolio standards. Different states had different interest in having wind located in their state or not. So really the transmission planning and ultimately cost allocation in question was, "OK, now we have all these new resources that basically have zero variable costs energy on the grid, what is that going to do to the wholesale energy cost. and how does that drive benefit?" and we use that as the basis to allocate the cost.

And then we are dealing also with what happens to new members. Because this was all done before the Southern part of MISO joined. So the question on the table now is the analysis about, do those resources actually provide benefits to the South? Is there an extension of benefits that can occur, and how do you get there? But at the end of the day for MISO it has to be about dollars on the table, and what are those benefits you're quantifying.

Question 10: I'm going to make a couple of observations to establish a fact pattern before I get to my question. And the first one is, if we look at PJM, we saw, with the integration of Dominion and the integration of AEP and ComEd, that all of a sudden transactions that wouldn't have taken place, or would have been harder to take place, all of a sudden we had a lot more transfer capabilities. So in some sense joint and common operations or just integration isn't just a substitute for transmission. So this issue of talking about transmission cost allocation kind of becomes moot. I think Speaker 2, your presentation brings that out very clearly—joint operation, at least in the real time market, and probably even more so if you did day ahead unit commitment and so on, is beneficial across the region.

And then of course the issue just came up about transmission cost allocation, and I'll note that some of the biggest holy wars we fight are over transmission. And if you look at the cost of transmission in terms of total wholesale costs, it's a drop in the bucket compared to resource adequacy, compared to energy, but yet we have the biggest fights over the smallest thing.

And so with that being said, my question is really for Speaker 4. Why isn't the Southeast thinking about going down the road of more coordination, almost at least an energy and balance market type mechanism similar to what is happening in the West now, given that the Southeast and the West has historically thought very much the same way? Why isn't that happening, given the economic advantages that have clearly been shown with what's going on out West right now and what's going on with the integration of various systems within the RTOs, whether it's MISO or PJM? And why hasn't it happened, or why isn't the discussion taking place, and what are the barriers? Are they technical barriers, regulatory, political, distribution, as we talked about with cost allocation? I'm curious.

Respondent 1: I guess I'll try the short version and we'll see where it goes. In a lot of regards, some of my friends around the industry call Southern an RTO. If you think about how we run our fleet across multiple states owned by multiple companies—granted, most of them are operating companies of Southern Company--we get a lot of those advantages today of operating a large fleet from an economic dispatch standpoint. And the focus around our customers, with the lower than average across the nation price for our customers--I mean, we feel like we're getting pretty good value for our customers today, and the operation of the fleet, if you back up far enough, is not really dramatically different from what an RTO does. I don't know if that really hits your question or not.

Questioner: It does in part, but then I guess really my question is, why isn't there more coordination across the entire Southeast? If you're looking at SERC and FRCC (the Florida Reliability Coordinating Council) and VACAR South for example. If Southern Company is an example, it works well to have that broader dispatch across four states. Why not join forces with the other companies, including TVA potentially, and get even larger benefits from that?

Respondent 1: We've actually had some of those discussions, and quite frankly, the benefits that we see that go along with the constraints that it would create around how we operate today, I just don't know that we've seen the tremendous benefits that are there. So maybe some of it's a function of maybe topology of the system and how we're currently connected today. But we just haven't seen the tremendous benefits beyond what we're already getting today.

Question 11: Speaker 3, I'm just interested if you could give a little bit more background or insight on the NAESB process that you're talking about. I've been involved with NAESB Gas Electric Harmonization meetings, but I don't think that's what you're talking about. So I just wanted to understand what you were talking about on NAESB. And then for Speaker 2, on your benefits of having the larger integrated market, is that net of discussions that CalISO's currently having with stakeholders about potential changes to the export rules that would allow or facilitate more exports right now, short of getting to a full integrated market? Thanks.

Respondent 1: So I'm phoning a friend. One of what I consider the benefits of my job to be is that I don't go to NAESB meetings. [LAUGHTER] But basically it works through a series of subcommittees of different participants up to an ultimate vote and a recommendation to FERC. So I'm not familiar with the Gas Electric Coordination Committees. I don't know if those are the same or different.

Questioner: That helps. So it's a separate parallel flow of visualization and discussions I guess.

Respondent 2: On your question about whether the benefit analysis is net of some ongoing policy discussions on exports, I guess my recollection of what we've been talking about with regard to exports has been primarily around removing some market rules we have that link changes in export schedules in real time to a callback of congestion revenue rights. That's one policy issue that we're taking on.

Questioner: I know that one's going on, but also I'm talking about just where there's been some discussion about the transmission, and how the transmission rates are allocated on exports.

Respondent 2: Yes, the issue has come up. We charge a transmission access charge for exports. So load and exports pay our transmission costs. And the question has been, would we consider waiving that transmission charge for export as a way of incentivizing more exports on the inner ties? And that's something we're considering, but frankly we really don't view it as a huge impediment to providing export bids. It's something they can internalize in their bid. So if we have prices going negative, where we're paying people to take energy, it's very easy for somebody to recoup the cost of paying that export charge. So regardless of whether we went forward with this regional market or not, I don't think at this point in time we're going to seriously pursue waiving that export transmission charge for that reason.

Questioner: I guess that just then my question then is, what would the regional market do to facilitate those exports over what you're doing now?

Respondent 2: That's a great question. So you saw my slide with all those bubbles out there of all those balancing areas. In the West we have 38 different balancing areas. So the challenge you have with sinking that surplus power is that all of those areas, on a day ahead basis, even in advance of a day ahead, are already deciding how they're going to run their portfolio of resources. So they've lined up their gas procurement. They've started generators that are long start. So with respect to the ability to change the dispatch, where you can actually de-commit units and all that, there's only so much you can do under the current market construct. By having a broad regional market, where you now have a consolidated balancing area, you're now managing the entire fleet of resources for one balancing area function. You have a lot more degrees of freedom on which resources you start, which ones you don't. If you know you're going to have a lot of surplus renewables, you can make decisions about not running this gas plant or this other gas plant. And so you're better able to position the fleet to absorb those renewables than you will be just trying to sell it off under the ties, when you have 38 different balancing areas out there. There are just some real institutional barriers to exporting that power that we think a regional market would largely alleviate. And certainly the pancaking of transmission is another issue. If you're four balancing areas removed from California and you want to buy that energy, you still have to get it across four different balancing areas. So that is another reason we think that regional market will help on that.

Question 12: This question is for Speaker 1. I recall a couple years ago there was an incident where power was being scheduled into PJM, and then there was an outage that then required a TLR action that curtailed an import into PJM on the TVA transmission system. And you noted some of the work that you guys were doing with progress in TVA. And if I recall the anecdote properly, it is that TVA could have re-dispatched its own system to allow that transaction to occur, but then you guys were in a situation where you were scrambling to handle the loss of that power. I just wondered where your conversations have gone in terms of how to maybe alleviate that challenge or where that sort of issue stood.

Respondent 1: So the exact situation you're referring to you described fairly accurately. We had to curtail, I think it was something like 3,000 megawatts of imports. It set us very close to an emergency condition, because I think it was during the summertime that it occurred. And there was a generator that was very close to the sending side of that constraint, where if that generator would have been reduced it would not have necessitated that volume of curtailments. And so our discussions with TVA have resulted in operating guides that would allow for that type of very quick response in the future. So that we can avoid the level of TLR that we got to in those types of circumstances. So that was sort of an inciting incident, if you will, that led to some of these discussions of operating procedures that will allow us to operate reliably without that kind of disturbance, if you will, and significant impact to the system. So that's exactly the kind of coordination I was referring to.

Questioner: So is there a market transaction, or is it strictly just an operational action?

Respondent 1: It's an operating guide. I don't think our joint reliability coordination agreement with TVA provides for any kind of financial remuneration for those types of actions. It's more of a recognition that we could re-dispatch for the short term until we get a handle on the situation and can balance the system over the longer term. And there's a recognition that that's beneficial on both sides. So there aren't provisions for a payment from one to the other.

Question 13: Speaker 2, when you look out to 2030, what assumptions were you making about load on the system, and how confident are you in those load projections that you used to analyze the benefits here? So, there are out there a lot of different forecasts of what happens to load with the increase in generation behind the retail meter, and with increases in storage and the like. And I'm wondering how you took all of that into account and how it affects your results?

Respondent 1: The load projections used in the study leveraged the Western Electricity Coordinating Council's (WECC's) base case out of all the regions in the West used for planning. So we leveraged that planning base case model that goes out to 2024 and extrapolated the projected load growth out to 2030 when we did the simulation. What we're seeing in most of the states outside of California is that they are projecting load growth, not significant load growth, but a modest load growth, whereas for California, because of all the proliferation of behind the meter solar, our 10 year load forecast is actually flat or declining in certain areas, and that's a fairly significant change. The updated California forecast has really shown that quite dramatically. So those were the assumptions we used. The extent to which you'll see the proliferation behind the meter in other utilities in the West that might cause those load forecasts not to materialize is not something we examined, but I think you make a good point, that that might be a sensitivity we'd want to look at. If that load were flat, would those benefits still be there? For California, I think they would still be there from the integration standpoint. But it's something we may want to look at.

Question 14: To move towards the summary of this session, let me ask the panel a wrap up question. Would you agree that whatever the geographic footprint of your wholesale market is, that that also needs to be the footprint of the transmission planning? In other words, does it do any good to have one geographic footprint for a wholesale market, if it's not congruent with your transmission planning, given how central transmission planning is to the efficiency of a wholesale market?

Respondent 1: I don't think I entirely agree with that. When you look at something like policy driven transmission, you may look at getting access to resources outside of your operational footprint, and examine what it would take from a transmission standpoint to do that. So with respect to the examples of Wyoming and New Mexico, I talked about how, regardless of whether California is successful and moving forward with this regional market, we may want to and we are doing studies now to look at what are some of the least cost transmission to get access to Wyoming and New Mexico wind. And that involves traversing across states that are not part of our market footprint. But I think, from a planning standpoint, it's something we need to look at. I think other aspects of planning—obviously reliability, congestion management--those are probably more within the confines of your market footprint, but I think some of these policy projects would extend beyond it.

Questioner: The reason I ask gets back to the topic of this panel, "Beyond FERC Order 1000." Short of having a national wholesale integrated wholesale market and national transmission planning, do you think that the most likely thing beyond FERC Order 1000 is simply a continuation of the reasonable negotiations and just continuing to bump along as we are and work out these issues, as they come along, and is that most likely to be 'beyond FERC Order 1000?" That's sort of the overall question. And I'll ask all four of you to address that.

Respondent 2: From MISO's perspective, as I was thinking about the first piece of your question, about the planning and the wholesale market, we consider them to be overlapped largely because of this cost allocation question. That's why we think about interregional planning and cost allocation as separate from the regional planning, because at the end of the day, you're driving this transmission we're really talking about around market efficiency or because of policy changes or whatever it is, based on an expectation of benefits that manifest themselves through how you operate the system. And that's one of the things that makes coming to agreement on cost allocation interregionally so challenging. So it's challenging even when you mostly agree on those benefits, and it's about impossible when you don't. So from MISO's perspective, "beyond Order 1000," if I think about the interregional component in particular, I think is really about focusing on how do you drive that better alignment of the operations so that you can get that alignment between operations and planning that you need to actually get the transmission in place.

Respondent 3: I think that's right. I mean, back to your original question about your transmission planning footprint--and for me the bilateral market and transmission planning, those two things are intertwined. So I think they are the same areas, because my long term transmission plan is also tied directly to my long term resource planning as well. And that is my bilateral market. Now, granted, I may be buying something from Oklahoma that's outside of my footprint, but that's just a transaction, from my perspective.

Questioner: That's just a two party transaction.

Respondent 3: But I think in terms of "beyond Order 1000," I think Respondent 2's got it right that we need to continue to work towards identifying those operational things that lead us to better answers long term down the road. We're going to have regional differences that we're going to have to work through. There's not an easy answer here. If there were, we wouldn't be talking about it. But continuing to work through those regional differences and coming to some common ground is where I think we're headed.

Respondent 1: I really think the interregional coordination process and Order 1000, I really think FERC took that about as far as it could from a jurisdictional standpoint. You can only go so far in enforcing a framework and cost allocation process. So I think it's going to continue to be incumbent on the different planning regions to collaborate and coordinate. It's hard work and the cost allocation is really hard. And it kind of is what it is, short of consolidating regions like we're looking at in the West. I think the interregional process we have now is probably what we're going to have to rely on.

Questioner: Well, just from a constitutional standpoint, FERC can go a lot farther than they went. I'm not advocating it. Politics get involved. But constitutionally they can go out farther than they did.

Respondent 4: Yeah, I don't have much different to say than the other panelists. I think on the operational side the goal essentially is to try and make it look as much as possible like there aren't different systems by operating as closely together as possible. It seems like the goal ought to be similar on the planning side. However, having said that, there are differences between the regions that are not going to go away, and as you know, we're going to sound like a broken record here, but as we said all along, the cost allocation issues are significant. I would love it if we could all recognize, like a previous questioner said, that the transmission costs pales in comparison to the capacity and energy components. But the fact of the matter is, it's still real money, and so that cost allocation issue is still going to be something that has to be addressed and considered and really kind of overcome if we're going to go further down the road than Order 1000 in terms of, again, making it look like we're planning inter-regionally as if we didn't really have a seam between.

Questioner: Yes. Two or three billion dollars for an interstate transmission line, its real money. Everett Dirksen used to say you know, "A billion here, a billion there and pretty soon you're talking about real money."

Session Two.
Retail Rates: What Are We Missing by Perpetuating Tariffs without Meaningful Price Signals?

Retail electric rates in the U.S., with a few exceptions, remain largely devoid of meaningful price signals. Rates tend to be based on average costs, insensitive to the real time dynamics of supply and demand, deprived of transparent demand cost price signals for at least some customer classes, and completely unreflective of the realities of fixed and variable costs. In the absence of meaningful prices, we have launched into debates about "value" of assets, net metering, customer desires, social externalities, and a host of other highly subjective, often non-economic considerations. While there is nothing new about those debates, there is the very basic question of why in the age of smart technology, sophisticated wholesale price signals, corporate and/or functional unbundling, and consciousness of the need for greater efficiency in energy use, we perpetuate a pricing regime devoid of meaningful signals. What are we missing by not moving to more meaningful pricing? What products, technologies, services and/or market participants, for example, are kept out of the market? To what degree is retail competition impeded by the absence of meaningful retail price signals. Indeed, would greater retail competition lead to greater efficiency through a broader array of offerings or perhaps impede it because, as some have argued, retail merchants will sell hedged products that could dilute improved price signals?

Speaker 1.
It's a privilege to be back joining you again and talking about this topic. While the topic focuses on retail, I will spend a little bit of time talking about some retail issues, but I want to lay a foundation here by talking more about what it is that is missing in pricing, why we should care about it, and a little bit about how emerging business models provide us some opportunities to bring some of these pricing elements back and create some new value propositions. So I'll talk a little bit about some of the regulatory economic principles underlying efficient pricing and focus a little bit on how we move towards more granular pricing with an eye to two current issues, wholesale load settlements and DER valuation, and I will actually show you some data that gives you some idea of what kind of price variances we're talking about, and conclude with some discussion of value propositions.

As an economist and a former regulator, I need to begin with some regulatory economic pricing principles. And the first is that we ought to be looking at pricing, as Hayek told us, as a mechanism for communicating information. And that that is its real function. It fulfills that function less well the more those prices are rigid and don't reflect the underlying dynamics of a market.

So why should we care about pricing? We should care about it because, by communicating marginal cost and value, a dynamic and efficient pricing system can promote economic efficiency. It can thus enable overall cost savings and it also reincents appropriate innovation in the market.

A question that is often asked is, "Well, is it OK to charge different prices to two different residential customers, for example?" And I have to go back to an understanding of what the basic principle on price discrimination is. And that is that price discrimination occurs when a firm charges different prices to different customers for reasons other than differences in cost. So that if costs of serving different customers are actually different and you charge them the same price, you've created a cross-subsidy. And to eliminate that cross-subsidy is not price discrimination. You can decide whether the cross-subsidy is something that promotes some other social value, but more often than not, in my experience, at least looking at the data that we looked at in Ohio, it is low income customers who tend to be less peak oriented in their usage and tend to be at least somewhat price responsive, such that charging a flat rate often meant that we had low income customers subsidizing customers in larger houses with higher incomes and a greater ability to pay.

Finally, you're going to have to deal, in retail rates, with how you allocate costs that aren't collected at marginal cost. And there are some considerations that you should pay attention to. One consideration is horizontal equity--that you treat equally situated customers equally, and customers that are not equally situated, you can treat differently. A second consideration is competitive equity. You want to avoid subsidizing uneconomic entry. And, finally, you want to look at behavioral impacts. Are you distorting participant behavior in the market away from some efficient outcome? And we can talk more in the discussion about how those principles might apply.

I want to talk a little bit about a couple of issues that affect what prices are missing. The first has to do with how we settle loads in the organized wholesale markets. And here, I think it's important to understand what it is that we're actually doing, because this is something that we haven't paid a great deal of attention to while we paid a lot of attention to trying to price generation in these markets. Load is settled on an average zonal basis. That price doesn't reflect nodal differences in the load nodes across the zones in the organized markets. If we take New York, for example, there are 11 zones, which means there are 11 hourly prices at a wholesale level that apply to load within those zones. If we just take one of those zones, Con Ed, what the Con Ed folks will tell you is that I think they have 64 different distribution areas, only 20% of which peak with their system peak. Does it make sense that we're not differentiating those prices? We'll see om a little bit. We won't be able to see much about New York and I'll tell you why in a moment. The second issue is that these prices are hourly prices. They don't reflect differences between demand intervals or the ability to shift demand between intervals. And for most customers, they often reflect historical average customer class load profiles. What this means is if you're a retail supplier, you have absolutely no incentive to help your customer shift their demand to a lower cost interval, because you're going to be billed based on that class load profile, regardless of whether your customer is using all of their energy on peak or using all of their energy in an off-peak period.

FERC jurisdictional load settlements have been largely overlooked in the market development process, and they need to examine and actually collect some data and figure out what's going on in this market so that they can pay attention to it.

Another issue that I want to touch on is the issue of the valuation of distributed energy resources, which is, of course, the hot issue in New York and many other places. There are two basic approaches by which you can value distributed energy resources. One is a sort of administrative or planning based approach, the so-called "LMP + D" approach. The second is a market-based valuation approach, where you're actually beginning to calculate distribution level locational marginal prices or DLMP.

What's the difference? LMP + D is an average administrative forecast of what is essentially avoided cost, the same thing that we did when we did standard offer contracts years ago. And it is necessarily a forecast, which means that at any given point in time, that forecast is not going to be accurate. Moreover, LMP+D assumes and requires, in effect, a relatively transparent distribution planning process, and it requires regulators willing to review that distribution planning process to decide whether or not what they're planning is appropriate or not.

By contrast, DLMP is a granular market measure of short run marginal cost that is specific to times and locations and the provision and use of core electric products. The other piece of this is to look at the products that DER can provide. And there are really only three that we need to worry about. One is real power, the second is reactive power, and a third is various forms of reserves, and essentially everything else (sometimes you see a list of a dozen, and in a few cases, more than 20 different things that DER can do) is all either some combination of these three main products or something that is really unrelated to the core capabilities of DER.

What is important to note is that there are tradeoffs between these three products. If one is providing real power, one cannot simultaneously provide the same amount of reactive power. If one is providing real and reactive power and committing to that, one cannot simultaneously commit to be held in reserve to provide reserves that location. So you have to think about what you are going to provide at different times.

So let me switch now back and look at some data at the RTO level. This is an actual peak day in 2015 in a particular node in PJM. We would have liked to have done this analysis in New York. However, the New York ISO, when they calculate their zonal LMP, their software tosses away all of the nodal LMP values that go into that calculation, if it's not from a generator. So you can't actually do this analysis in New York, but you can do it in PJM. However, even in PJM, these are average hourly LMPs, they're not interval LMPs. So here I've taken a peak day for a particular zone in PJM, and this is what happens when you look at the zonal LMP through the day [values range from near zero to over $80/MWh]. But what we can do is we can then look at the same zone, and compare that variance to locational variance of prices at different nodes. Because when you look at the variance between load nodes, that variance is huge, with it maxing out at almost $900 a megawatt hour in one hour. There are 12 hours in which the maximum variance is more than $50 a megawatt hour, and in some of these hours, you have a majority of nodes in the system which are more than $20 a megawatt hour off from the zonal price.

What this means is that you're not communicating to people their opportunity to either use more or less energy. You're not communicating the opportunity to bring in DER where it actually could make a difference. And if you did, you would expect to see a response. You would expect to see these variances decline, and you would expect to see overall costs in the system be lower, because people would actually be getting the information that enabled them to do things that were cost effective.

Now, in the New York study, we went and we looked at what happens if you begin to take LMP down into the distribution system. And we (this is mostly Michael Caramanis's work) modeled an illustrative zone that was representative of commercial and residential loads. We modeled about an 800 bus radial feeder--so a relatively simple feeder. And we looked at a peak day and we said, what's the variance between the maximum and minimum real and reactive power LMPs along that feeder, compared to the LMP at the substation? Now, it's important here to look at both real and reactive power, because reactive power matters, because you need to control it in the distribution system. It is also a principal source of constraints within the distribution system. And we actually are beginning to understand, as we get AMI out there, that reactive power is not as well behaved as we thought, and is actually very important to manage here. So we're looking at DLMPs which reflect constraints. They reflect marginal losses. They reflect impacts on distribution equipment, and that's what you're seeing reflected in these differences.

The other thing that we looked at in New York was, what happens if you begin to think about platform economics? Platform economics is a different way of thinking about markets. It's not all that different from what we think about in RTOs, but it is different from the common sort of pipe way in which businesses operate, in which they assemble parts and curate a specific set of products which are then offered. So, platform markets are things like Airbnb. These are markets that globally represent about $3 trillion in market value and have grown rapidly over the last decade. Now, the term "platform" in this world is being used in lots of different ways. We've tried to use it in a very specific way, as representing the infrastructure that matches producers and consumers who transact over the platform. The platform includes components and rules designed to facilitate their interaction and creates value by facilitating matches and providing easy access to useful goods and services. Two of our co-authors on the New York study have a new book out called *Platform Revolution*, which I would encourage you to look at if you're interested in delving more deeply into this topic. Within the context of a distribution system, what it means is that, in addition to those DSO obligations for planning and operations, we're adding in market components. These include a transactional platform component that is really about trading those core electric products, as well as potentially a services platform, where you might enable a range of services to be traded from the platform provider and third parties, perhaps enabled by some of the data and adjacent services that the platform provider or utilities may be in a unique position to provide.

So I'll talk a little bit more about the transactional side of the platform, and if we want to talk more about services later, we can. This chart is a basic outline of what a potential transactional platform market might look like. In addition to reserves at a system level, the basic products might include distribution specific reserves, where there are specific DER products needed to support the distribution system in a particular area. And you might be enrolling distributed resources in the utility's reactive power or volt var management program. You would see some revenue from marginal loss surpluses coming in to support the revenue requirement of the distribution utility, and you would see a whole set of transactions going into supply wholesale and retail power.

So if we think about how this market may emerge, one might think about an evolution, in which we first move to a nodal level in the wholesale market at substations—and "enhanced LMP" or "ELMP." And ultimately progressing down into the distribution system where the variance in prices justifies the additional expense of moving to DLMP.

So what you would see traded here is you would see a forward market that allowed continuous forward trading but closed immediately before the usage and delivery of energy into the system for a particular interval, followed by an ex-post market, much like the real time market in the RTO and ISO world, in which imbalance prices are calculated based on actual topology, actual power flows across the distribution system. It's a relatively simple calculation once you know those factors, and you can calculate, then, what the imbalance prices would be, and you would expect the forward trading to trend towards those imbalance prices.

So what would we expect to see here? We would expect to see that the distribution utility might be buying some option contracts in the forward market that would allow it to operate its system more efficiently. We could see customers buying in a forward market as they set their usage schedules. We could see that market opening to DERs, so that DERs had more opportunities than simply playing in the RTO demand response programs. And we could see both suppliers buying there and virtual participants who are willing to take the basis risk in the forward market. The imbalance market would settle much like the real time market in the RTOs, and it would provide an ability, ultimately, to settle the energy that is delivered through the distribution system at a delivered DLMP, if policy makers desire to do that.

So let me conclude by talking about two different value propositions that this provides. One is creating a market for DERs. So this is an opportunity for DERs to participate in the market by providing those electric products, real and reactive power and reserves, where it is cost effective for them to do so. It is also an alternative to providing a more generalized subsidy, whether through net metering or some other means, to DERs, where it oftentimes will support them where they might be uneconomic, or even where initially one or two might have been economic, but those economic values are exhausted as you bring more DER into that location.

It also provides the opportunity to animate a retail energy supply market so that that market moves from a commodity market to more of a services market, relying on the data that is being generated in the operation of these markets both to better understand what prices are going to be and how to more efficiently integrate a whole set of services that can be provided from buildings and DER into the efficient operation of a market.

The second value proposition that I would like to touch on is the value proposition that is associated with enhanced asset utilization in the system as a whole. Today we build for system peaks. We don't manage when energy is used, and what that means is that we have generation capacity factors generally less than 50% and asset utilization and transmission and distribution that is even lower than that. This can be compared to almost every other capital intensive industry, where asset utilization is over 75%. So we are lagging behind a lesson that other capital intensive industries learned 20 and 30 years ago, and that has real cost for consumers. What we have a pretty good idea of (we certainly need to do more to better understand and quantify it) is that a large portion of load can be shifted in time.

I put on the right-hand side of the slide some data from a study that was done by a woman who's now a professor at the University of Michigan, looking at what would happen if you could control just one degree centigrade of thermostatically controlled heating and cooling loads, two degrees in refrigerators, and four degrees in water heaters from California residential customers. The potential is there to move a majority of demand in California to other intervals, simply by operating these devices as if they were batteries, rather than simply allowing them to use energy whenever they wanted to. And as we develop smart connections to these different devices, we have the opportunity, not just in the residential sector, but much more quickly in the commercial sector, where we have buildings that have high amounts of thermal inertia, to begin to manage much of our demand through precooling, preheating, the way we would use a battery, and get much more responsive and much more efficient load curves.

So, as we go forward, we could see wholesale loads being settled such that suppliers have the opportunity and incentive to compete to help customers efficiently manage demand. We could see customers having choices, perhaps a lower flat price in exchange for giving their supplier control over some element of their demand, perhaps a dynamic price with some guarantee on maximum prices, or perhaps actually a real time price--as we've seen, customers in some places that have been given that opportunity actually like the opportunity to see real time prices, but I think, ultimately, the point is that we can give customers choice, and we can give them the opportunity to manage their demand in a way that's much more efficient.

Question: Great presentation. Did you say earlier that low income customers are subsidizing other residential customers, and can you clarify?

Speaker 1: We did an analysis when we put AMI in in Ohio. I'm going back to my days as a commissioner. And we asked one of our utilities to look at customers who were on the low income programs. And they, overall, were less peak oriented in their load curve than average customers on the system. So, in effect, what that means is, at least on average (I'm not saying that there might not be exceptions to the rule), but at least on average, low income customers on a flat rate were in effect subsidizing customers at middle and higher incomes.

Speaker 2.

Good afternoon. Thank you very much for the invitation to be here and the hospitality. It's a pleasure to be here.

I think the tenor of this presentation may be a little bit different. I know that many here in this room do focus almost exclusively at times on principles associated with economic efficiency. And not to be completely derogatory, but they often bow down to the god of the price signal, and when we're talking about time varying rates in the residential sector, and particularly among lower income households that don't have a lot of appliances or relatively few, and do not have access to some of the energy management equipment that some of their counterparts may have access to, the whole notion of the price signal as paramount comes into question, and we have to remain focused, at times, in this room, I would urge, on principles that are not delineated as fully by Bonbright and others, but that have to do with equity, have to do with home energy security and those aspects of consumption of a good that is really an absolute necessity of life. So that's by way of disclosure here.

Now, because of all this, I'd like to talk a little about residential time varying rates, and answering the question, "What are we missing by staying with flat rates and not adopting time varying rates?" Now you have to remember I work with a bunch of lawyers. I'm not a lawyer. You can let go of your wallets. I am not. But I'm going to give you an answer based on discussion with many of the attorneys that I work with. It's an unequivocal, resounding, "It depends." What we are missing depends on the customer, depends on their circumstances, depends on the service territory in which they're located, the wholesale market conditions, and numerous other factors. There is no one size fits all in making a statement about which rate structure we're going to mandate for residential consumers, and I absolutely agree with what Speaker 1 said, that the potential for system savings through shifts in consumption are far greater in the commercial and industrial sectors than in the residential sector.

So I'd like to shift to the tenor and tone and substance of the debate that's unfolded around time varying rates in the residential sector and around AMI. Proponents, as we're well aware in this room, extol the virtues of the technology, the reliability benefits, the operational savings that come through the ability to remotely connect and disconnect customers, for example, in the adoption of AMI, the cost of power, the savings in the expenditures on power through the shifts in consumption that are anticipated, avoided generation and transmission... I think folks in this room are pretty familiar with the purported benefits of AMI and the implementation of time varying rates.

The opponents, or at least skeptics, place their concerns into three basic categories. And it almost never varies, state by state, whenever the debate comes up. There are questions related to the cost of new AMI systems, and how the risks associated with the costs and touted benefits are going to be allocated. Is there going to be preapproval? Does there have to be some demonstration of savings? How are we going to allocate the costs, which are, in most cases, significant? And now, with no more Recovery

Act, when it comes subsidies for new systems in the about 50% of the households in the US that do not have AMI at this point…it's a very real question. The second concern has to do with remote disconnections. As a low income advocate, this really is an important concern. We've seen, with the implementation of AMI, sharp increases in disconnections in some jurisdictions where they've been rolled out. And the third set of concerns has to do with worry over penalties associated with time varying rates, particularly among those customers who are maybe a little more temperature sensitive, vulnerable to loss of service, and who may not have ready access to high tech appliances or energy management equipment.

As a consumer advocate, I find it impossible to deny the potential for benefits in rolling out a system that provides my clients and other residential customers with enhanced information and with the potential to shift consumption and pay less as a result. Those are good things, and I would not jump into the "just say no" camp because of that. However, I think it's really important as we go forward in the states that are considering new AMI, and even in those where it exists and implementation questions are on the table, that we just shift the conversation a little bit and start to tie together the technology and policy questions that arise. I would challenge proponents of AMI and stand willing to work with you to, as you put forward your proposal, do something a little different, lead with a set of policy and programmatic recommendations that you're willing to support and stick with. Lead with that, rather than what we all know is going to be said about the prospective benefits. But let's shift it up a little bit. In terms of what you may want to recommend, if I can be so bold as to suggest, come forward with a proposal for a fair allocation of the risks associated with these new communication and metering systems.

Let's face it, calculations of benefits that may accrue in the future that come from shifting of consumption are speculative. There is risk associated with investments in AMI. A reasonable proposal for allocation of those risks might bring you into a better position to negotiate with state consumer advocates and soften what might have otherwise been a "just say no" position. Come forward also with a proposal to enhance regulations and rules that protect health and safety and customers from disconnection of service. When you don't have to have somebody with a wrench to go and shut the meter off, and the utility can shut off more frequently at the push of a button, or allow an algorithm to accomplish that task, the concern about home energy security is very real. I would point to a situation in California where, after there was a sharp increase in disconnections after the early roll-out of AMI, the stakeholders got together and agreed on benchmarks for disconnections. It was a very interesting concept. There was renewed focus on disconnection protections that apply to low income elders, folks with disabilities, and others, but setting a benchmark in place where a company, if exceeding those disconnection benchmarks, would actually have to adhere to a higher set of consumer protections or a higher level of consumer protections on shutoff. If nothing else, this got people to the table and starting to get imaginative about ways to keep people connected to the system. But to come forward, along with the technology proposal with a policy proposal to enhance consumer protections may make sense if we want to change the conversation a little bit.

Along those lines, I want to make a quick statement (and this is difficult for me) about prepaid service. With AMI comes the enhanced ability or enhanced economics associated with implementation of residential prepaid service. And we don't have time to get into this the way I would like to, but what the data show throughout Europe and the United States is that with prepaid service comes an increase in disconnection rates five to 10 times over that of post-paid customers. We also know that wherever prepaid has been rolled out, it's concentrated among lower income households, and despite claims by proponents that this is a great conservation tool, the concern among consumer advocates is that really what this is is a credit and collection tool, and that when a customer is faced with disconnection for nonpayment and opts to go with prepay to either avoid a deposit or a disconnection, well, they forfeit consumer protections that otherwise apply in most states. I'm going to have to leave it there with prepay, but would be more than happy to talk with folks about that in the future.

So, finally, in promoting in AMI, I would suggest people come forward with a set of policies to at least ease customers into a new system. Obviously education and customer outreach, that goes without saying, but there are other structures that can be adopted to ensure that there won't be too many customers who face severe penalties. At the outset, provide options, rather than mandate a time varying rate. Offer structures such as shadow billing so that a customer knows what the expenditure would have been under various rate options. Provide, at least for some customers and for some period of time, a hold harmless provision. If you're a low income customer and you think, "Well, maybe I can save on the critical peak rate or some other time of use rate," give a period of time where if that doesn't in fact occur, that that customer can be held harmless. If you've come forward with proposals like this and are really willing to support them, I don't represent other consumer advocates, but I would anticipate that you'll face a very different environment at the state level in doing so. So don't separate technology and policy. That's my plea, and thank you very much.

Question: Approximately how many customers or what percent, is prepay? I assume it's very small. Is it? What's the size of that market?

Speaker 2: To date, in the United States, prepaid electric services are concentrated among some municipal and cooperative utilities. However, this is changing fast. Some of the largest investor owned conglomerates are looking to bypass state regulatory consumer protections and implement prepaid service at the state level. So it's a small percentage right now. There are larger percentages in Arizona and Oklahoma and Texas, but small. This is coming, though. The technology is here, and I think a lot of utility companies love this. And I think it really is dangerous, in looking at low income consumption and peak demand, to focus exclusively on those customers that participate in existing utility energy efficiency or bill payment assistance programs, because we can show conclusively that this is not necessarily a representative sample of all low income households.

Question: Is the increased disconnection level with prepay associated with the design of the prepay program? Or with some behavior or characteristics of those who enroll in prepay?

Speaker 2: It's the design of the program. When the prepaid credits are exhausted under prepaid service, the way the business model is right now and the way most of the programs operate is the customer is remotely and immediately disconnected at the first allowable juncture. Allowable in that many of the utilities operating these programs will respect a temperature based disconnection moratorium, for example. But that's the reason. Plus, it's lower income customers who are paying six or seven times per month during peak periods in the summer where it's hot. And we have an income issue here. There are a lot of households taking the service who just don't have the money to make ends meet at the end of the month, and it's just a reality. So, when you have a program that's structured that way, people are going to lose service more frequently, and that's been the experience everywhere that I'm aware of that this service has been implemented. I would certainly be willing to see evidence to the contrary, if there is any. I don't think there is.

Speaker 3.
Thank you very much. Today I would like to introduce maybe a different angle on dynamic pricing, and two perspectives. First, I'd ask each of you to consider that dynamic pricing is a tool of accomplishing for specific objectives, and I'll talk a little bit about that. Second, I'd propose that the effect of this dynamic pricing is greatly enhanced when deployed with precision, and I think Speaker 1 was getting at that, both in terms of pricing and the customers that you're targeting, as well as within a microgrid framework, and I'll explain that today.

Let me talk a little bit about the microgrid architecture and why it's critical as a foundation for dynamic pricing. If you think about our electricity system, I'd like you to think about it differently. Let's think of FERC and the ISOs as similar to our federal government. And let's then look at the utilities and the public service commissions as our state governments, as an analogy. What's missing? Think about a state with no cities. When you really think about governance, and how we form the United States and other countries around the world, if you didn't have cities, would your garbage get picked up? How would your roads look?

We would assert that that is what's missing, and that, really, a microgrid is local authority and control. I'll explain how utilities can participate in that with private microgrids.

So, really, we see two things emerging in the future: a utility microgrid and a private microgrid, and a network of those all working together with resilient facilities nested within that.

So here's an example of building out a utility microgrid for an investor owned utility such as Con Ed. This is Westchester County. They would begin to look at working with each of their cities to define a city microgrid, defined by the boundaries of those cities. And now they're actually doing specific measurement of capabilities as well as performance outcomes.

So when you think about a microgrid, it's really two things. It's about local authority, and it's also about producing specific outcomes. So it's very different than how the Department of Energy might define a microgrid, which is something they can island. Instead, what we're saying is that it's just an entity that produces specific measurable outcomes and that also has local authority.

With that in mind, you can develop a scorecard. You can have your SAIDI (outage duration) and SAIFI (outage frequency) for every city within your territory. You can assess how price responsive your grid is, how much demand response, storage and generation there is--you can measure that. And so we can know how price responsive each of those city microgrids is. You can have a load duration curve and know the utilization for every one of those microgrids. You can have percent of capacity, which substations are reaching near capacity. You can now also measure reliability and resiliency. But these are also important to dynamic pricing, and I'll explain why. Islanding capability is something you can measure, and so is how much total island substation alternate supply there is as a percent. You can measure your distribution automation and redundancy, which is what's called self-healing, as well as you can now have a master controller at the utility scale. You can also have energy efficiency environmental metrics.

So, as you see, now you've built out a scorecard for every utility and every private microgrid within the country. This gives us specific goals, and I think this is what Speaker 1 is talking about. These are the things that we're going to accomplish as specific improvements in these areas.

So how does that establish a foundation for price response? Well, right now you have this radial system. So, this chart represents a city. This is actually the city of Hinsdale in Chicago, Illinois. And you've got four substations serving this city, all radial, fused at the substation level. A three-phase fusing. If you blow one fuse, the utility doesn't even know it--all the industrial customers are sitting there on two phases. Their motors are being destroyed, and there's not situational awareness to even know that that happened. We see that all the time, in talking to city mayors, because their industrial people are coming to them saying, "We're having all kinds of problems, can you help us?" And there's usually no relief, because the city has no authority to help, and the utilities have bigger concerns.

So what's happening over time, and what you're seeing when you hear people talk about the smart grid, is that it's about a self-healing distribution system. You accomplish a couple of things when you enable dynamic pricing. Because now, when I loop these circuits and I put smart switches throughout, I can sectionalize, but I can also shift load immediately in real time, so if you've got solar, and you've got plug-in electric vehicles, and I can do some of that looping from substation to substation, so I can shift load from substations automatically. These switches operate in three cycles. So customers don't even know. So now you have a system that can accommodate two-way power flow. It can use the dynamic pricing in real time, and you've got software that's just moving the system in real time. It's called the master controller. Denmark is one of the first utilities to use a master controller to control all of the customer distributed energy assets to manage frequency, to manage load capacity, to do other things they need to do what Speaker 1 was talking about, what we call a distribution system ISO now. I think that term was coined by ex-commissioner Wellinghoff from FERC. You see it now as you build out your smart loops, your smart switches, and you start to get distributed energy throughout. Now you can call on your distributed energy when you need it. Like Speaker 1 said, when the solar's gone away because of a cloud, your distributed energy is kicked in immediately, etc.

You can also, now, through these utility microgrids, identify all your critical facilities, and you want to build islanding capability at these critical facilities, so you know the circuits, you know the address, and you can track the resiliency capability. But once you have islanding capability at these critical facilities, they now become a dynamic response resource.

In order to create an elastic electricity market, we need more assets at the customer level. And I'm not talking residential here right now. I'm talking about working with your big commercial and industrial customers. There's plenty of demand there, such that if they can build islanding capability for that, then you can leverage it to create this elastic market through dynamic pricing. Now, say, they've got a utility master controller, and it's doing a number of things. It's doing conservation, it's managing power quality in real time. It's there for economic purposes, like Speaker 1 described. It's also there to island. In cases like Hurricane Sandy, now, you've got portions of the grid that will just island. They'll automatically operate on their own. Your gas stations are going to work. Your hospitals are going to have power. Your grocery stores are going to be open for you. (At least outside the impact zone. I'm not talking about the impact zone itself. That's destroyed.) But at least around the impact zone, like we saw in Hurricane Sandy, you don't have the entire region blacked out and no one has anything. But now, all those assets that are there for the next hurricane are also there every day. Hourly pricing. Demand response. Now we have an elastic market, and things are operating much better.

So this is sort of the foundation. But the utility microgrid also opens up a new relationship between the city and the utility, where not only are the utilities are investing in smart grid through some rate, what I'll call commission rate, but in Illinois, I'll give you an example. We have Rider LGC (Local Government Compliance Adjustment). It's a really cool rider. It allows the city to specify investments in the grid, and it gets paid for on the customer's bills only in that city. It's actually like a new revenue service. You could see utilities providing district energy in the future. In order to help expand district energy where the private sector's maybe doing the boilers and the chillers and the power, the CHP, you've got the distribution company moving from electric distribution and thermal distribution to help expand district energy.

So where does dynamic pricing fit? Well, referring back to Speaker 1, what are your goals? Here you can see some specific goals that you can establish with your dynamic pricing program [conservation, consumer cost reduction, CO2 reduction, permanent demand reduction, temporary demand reduction, load shifting, and price responsiveness]. You can then see that you have rate options: event-based versus market-based pricing. And I think you'll find they serve two different purposes. A lot of times you'll see utilities wanting to focus on event-based pricing. You will not get much investment from event-based pricing. It's just not enough money. When you're giving a customer $10 a year or $20 a year, it doesn't give you much capital to invest. So market-based pricing is where you really see the investment. So if you want investment, you need to move to the market-based type pricing, and I'll show you an example of that. You can develop your own matrix, where you've got your desired outcomes on the left here, and then you've got event-based pricing and market-based pricing as possible rate structures. You could use numbers to quantify what you think you might achieve towards each goal with the different pricing mechanisms, or you could just rate them as "high, medium, low," and you can start to see what each of those types of pricing will do towards your goals, and build out your own program.

But as Speaker 1 discussed, one of the things we're after is improving underutilization and also avoiding capacity constraints. In the private sector, when we get close to our capacity constraints, we don't go ask the Commission for money. We actually find a way to reduce our demand so we don't have to install another substation. And so at one of the campuses we've been working with, they've been managing their demand right at 12 megawatts for the last six years. And they've added four or five new buildings. They've refurbished several buildings. They've added a ton of demand, but they're still sitting at 12 megawatts. That's how the private sector deals with capacity. Whereas on the utility side sometimes they'll just go ask the Commission for more money to build out more.

You don't have to keep doing that. And here's why. You can see how, once you have a number of distributed energy assets, during those peak hour periods, you can have your customers go to zero. I'm not talking about net metering. I'm not talking about putting power into the grid. I'm talking about customers just taking their load to zero whenever you ask them to. And they'll also put in storage, things that will actually increase the load at night, so what you'll see is your asset utilization will go up, and your peaks will go down. So you're after flatter curves. You're after expansion being avoided. These are some of the goals.

Typically, when you see a customer going to islanding capability, it's usually a suite of assets that they'll put together to create islanding capability.

So how does dynamic pricing play in this? It's interesting. When you come from the private sector and you're looking at investing at the customer side, the utility and the Commission controls everything. You set a price, and that price determines whether or not anybody invests in anything. So here you see utility flat rate of $80. The customer CHP, let's say, costs $60 to run. That $20 delta is not enough for me to invest. If I already have the asset, I'd run it all the time, which isn't necessarily effective for anybody. And there are a lot of customers that are out there just running full time because they installed the asset a long time ago and the rate's a little bit higher, and so they just run. And say that a customer generator is going to have an $85 strike price. But now, if you put in a time of use rate, you've now effectively controlled when the CHP operates. This happens a lot in New York, where you have big demand charges. And so, customers will operate their CHP to avoid the demand charge, and they won't operate at night. So, you've effectively controlled when they operate. Now, if it was a simple cycle generator, it would only operate from 12 to 5 pm in a three-tier rate like this. So, again, the utility and the commission have complete control over when these assets operate based on prices.

This next slide just shows you why a flat peak rate wouldn't pay off. It would have an 11-year payback with an operating cost of $60. So it just doesn't work, and you'll see most customers would not invest in that scenario. But if you went to a time of use rate, this produces the same revenue for the utility. There has to be a fairly high on peak rate to get that same revenue for the utility, but this TOU rate would produce a five-year payback.

Now, depending upon interconnect costs, depending upon financing cost, this may not be enough. But let me give you an example of how it's working in Massachusetts right now. Let's just take a medical campus, about six million square feet, 70 buildings. Here are the NStar and National Grid rates. So, we were working with two different hospitals, one in National Grid's territory, one in NStar. You can see very different rates here, because you can see that the demand charges are very high for NStar, whereas the distribution charges are very high for National Grid. So two different approaches. One is using high demand charges and very low distribution charges to target the customer to get them out of those peak periods. The other one's using a very lukewarm dynamic price signal. It's mostly on the distribution side. They actually end up accomplishing similar functions.

What's interesting is that now, because we're in a restructured market, the supply side's completely separate, so now you have a power supply cost and you have fuel costs and you have an ISO capacity charge.

We're going to use the real time price as an indicator of how much market power is really being exhibited on these customers. So if we run their load curve against the real time price, we actually know what they would have paid in the real time price markets, and I'll show you what that looks like. But here, we're just going to use it as an upper limit of where they could go to.

So here's the load curve for a customer. We use the same load curve in both, even though they were different. I'm just going to use the same one for comparative purposes. There's about a 55% utilization. Here's how their costs came out with those two rates structures. You can see the costs came out at about $131 a megawatt hour, just for electricity, for NStar, and about $126 per megawatt hour for National Grid. You can see power supply costs dominate. The demand charge dominates for NStar, and the distribution charge dominates for National Grid.

This slide shows the stack order that was optimal for the sites due to their thermal load: some baseload CHP that would run all the time, some supplemental CHP, demand response for conservation, some natural gas for peaking, and then some demand response for load curtailment.

A system like that would cost about $30 million for capital costs. It has some operating costs. But here's the interesting part. If they're going to go into real time pricing, which is what a lot of customers are starting to look at, at least at the commercial level, they can island whenever the price is above their operating costs, and then they can buy in the real time price markets. And you can see, their average real time price was $29, versus paying a supplier a flat rate of $75. There are huge savings for them in the marketplace.

In fact, if they operate in real time prices, the savings are huge, about $37 and $32 a megawatt hour, and they're still buying 82% and 75% of their power from the utility.

So, here the case where the ISO price signal now would have the customer operate in a way that's beneficial to the distribution company and has huge savings for the customer.

But the customer's going to keep going, because the demand charge offers some additional savings opportunity. It's not a lot, but it's going to help them make the business case for investment. Now, utilities can control this by having a standby charge.

So what I'm going to offer here today is the idea that utilities can move to more of a dynamic demand charge, something that's more precise, that's very precise in terms of when you want these systems to operate, and just like the real time pricing, when you want them to operate, so that they don't have to be being off from 6 am to 9 pm every Monday through Friday, which is the way the demand charges are structured right now, and which isn't necessarily optimal for anybody. This forces them now to have the distribution company only supply about 50% of the power.

Now, let's look at all the savings. Everyone thinks CHP thermal is where it's at. It's not. To be honest with you, the bulk of the savings you can see here comes from the supply side. In the case of NStar, it's distribution, a demand charge. In the case of National Grid, there's a lot of savings associated with the distribution charge, but you also get some ancillary service. You get some from the energy storage. There's some demand response. You've got some operating costs, but you could see 43% savings, about a six to 6.2 year payback.

These savings are pretty good, but they may not be enough. So this is where you can be very strategic in how you design your rates to maybe move, in a targeted way, some of these facilities into investing. Once they've invested, they can move over to an operational side, and what I would argue is, right now, under this scenario, this would cost the utility 50% of its revenue. What I would argue is you don't have to offer that forever. So, if you want the customer to invest, maybe what you do is you offer a limited rate, where you wave the standby charge for five years. Let them invest, then let the standby charge come back in again. Once they've paid off the asset, now all they need is the supply side savings. And maybe some, like Speaker 1 said, maybe some ancillary services things could pay, so the distribution company can use that asset.

So what I think what you're really trying to do, as a regulator, is encourage the investment, get the assets installed to protect all your critical facilities working with your cities, as well as get some other facilities--your big campuses, usually your universities, can all go to islanding. They can be in the real time markets. And now think about New England, with 2,000 megawatts of islanding capability. What's going to happen to your market prices?

And now the distribution company has all those assets to use now and to manage. When you bring in all this solar, and you bring in the plug-in electric vehicles, they've got all the assets they need to manage all that demand in real time. It's a huge…but again, I think we're talking about a targeted approach: this is what we're going to do, here's our goals and here's how we're going to get there. Not, "We're just going to throw some rates out there and see what happens." And I think that if we utilize that self-healing distribution, there's not enough money out there right now, I think, for the ratepayers to pay for that, so I think if you get the cities involved, the cities will want to invest. And I think they'll be willing to have their rates go up a little bit. And they do this all the time. They make choices all the time for a city's future in terms of how they're going to spend money for roads and investments, so that they should have that authority and that ability to spend a little more if they want to spend a little more to give themselves a competitive advantage, to drive themselves to a new place. And I think you'll find they'll do it very wisely. Let the utilities build master controllers and then use targeted dynamic pricing specifically to lower wholesale prices and to protect your critical central service and give you what I'll call that power quality management and price at the distribution level. So, that's all I had. Thank you very much.

Speaker 4.
Thanks. So, the whole lens of what I'll be talking about today will be from the perspective of a retail energy company, and a company, just to put that in perspective, with about a little over 20,000 megawatts of peak demand across numerous markets, all served without any generation, so using purely the market to provide that service.

Let me talk about four things that we look at as sort of the trend line: a digitized future, a distributed future, a decarbonized future, and a designed future.

In digitization, I think we all understand what is going on, and we heard about markets and platforms. I think it's 50 million smart meters that are out there, and we're using them now, but only at a very small level. We really are not doing what we could do.

The trend of the distributed future, I think, goes without saying. And distributed energy, as some of the other panelists discussed, is not just building solar. It's really, how do we use megawatts and flexiwatts? How do we change demand, either through structured programs or the marketplace, to change the usage of energy?

The decarbonized future clearly is going to be a big part of where we are. Independent of people's political views on carbon, I think society is making a decision for us, and voters and consumers are going to vote with their feet.

And then, finally, what I would call the fourth D, sort of in the future, is what I call the designed future. And I think, as Speaker 2 said, it's not a one size fits all future. I think the key to where we are with technology and consumer appetite is that we have to design for individual consumers, be they businesses, as Speaker 3 discussed, or even homeowners.

And those four things, a digitized future, a decarbonized future, a distributed future, and a designed future, is what we have to think about, across the market, when we think about where we're going.

So, as we talk about pricing, retail pricing in many regards today, especially in the regulated frame, is really confusing and it's random. Speaker 3 just used a solid example. Two businesses right next to each other here in Massachusetts see completely different tariff prices, completely different economic decisions, even though they may be serving the exact same market of Boston or some other locale. So it's random in that regard, and we also have misaligned input costs. So we don't know, in fact, the right seasonality of pricing, or the right timing of variant pricing. A great example is the polar vortex. Now we may say that New York City and New Jersey are different wholesale markets. That's fine, but people in Northern New Jersey, during the polar vortex, saw no price signal, because the utility offer was the same because of the way they set up the market. Now, in New York City, we saw a very different outcome. Prices ran up dramatically. And then, on top of that, in other parts of New York, we ended up showing customers not as much price movement as there truly was in the wholesale market, because we, in fact, carried cost to a later period. So my second point on how pricing is sort of random and confusing is this misalignment of input cost.

My third point on this has to do with the subsidy question. I think a great example of this is in Nevada. We ended up in Nevada with a rapid growth of residential rooftop solar, driven, in some regards, by a subsidy or by a structure that was designed by the regulators. They made a different decision, and overnight changed the entire economics of an industry with one signature on a piece of paper. That unclear subsidy path creates, again, confusion in the mind of customers. You saw with Speaker 3's presentation just recently that the payback between one design and another is three to four years. For businesses, 4.9 years or 5.2 years is the decision between doing something or not doing something. So when we have unclear understanding, it causes confusion.

And then, finally, I think often the reason that regulated prices often are confusing and random is really, and I'll just be honest, the focus on the past. In my business, when I make an investment, when I buy something, if I've not done a good job of making a good choice, that cost is borne purely by my shareholders. Often we don't do that in the electric utility industry. We look too much at what's gone on in the past, and that causes institutional inertia around where we're going. Sometimes we're too slow as an industry.

So what I would say just briefly is that competitive retail simplifies that for consumers, and it can be thought of in terms of a number of products and a number of opportunities.

First, when we think about providing cost certainty or sustainability or energy efficiency, that all comes from a framework of us looking forward into the market and bringing those forward prices back to consumers. I think the point made earlier today was that we may not be bringing all the prices back to consumers, but a retail market does it as best it can in today's world, and I think we'll see that.

If you look at places like Texas, the ERCOT, market, I think there's a huge improvement in the efficiency of the market, because we are beginning to use all of the data in settling, in fact, at still the local level, but setting against the customer's actual usage. That's a big difference from what we see in the Northeast, and I think a huge difference across the rest of the country.

Just to talk about some other products, we talk about time variant products. The other thing that the competitive retail business will bring is a consumer friendly approach to time variant products. So, imagine if you were driving along a freeway in Houston today, and you were looking at a lot of billboards around electricity or a TV advertisement, and somebody offered you 100 free days of electricity. Would you believe that you could get 100 free days of electricity in America today? Would anybody believe that? (Except maybe me or Rob Minter who lives in Houston.) Well, we do, we offer, in fact, 100 free days of electricity. Now, is that a time variant product? I don't know, I think it is. Anytime from 6 at night on Friday until midnight on Sunday, you can have zero price electricity. If you will switch your load, your dishwashing or cleaning or whatever you can do, you will create value for yourself. On peak, just to put that in perspective, because we don't want to bait and switch consumers, it's about 9.2 cents a kilowatt hour. That's all in, including distribution and transmission. So, if you use more during the week, it's not going to cost you that much.

This is a picture of what else the competitive industry's doing, and it really comes down to how we are using energy differently and really providing information differently. All of our customers in Texas today can see a disaggregated bill, a grocery bill, if you will, a shopping bill, if you will, on the appliance level, at no extra cost, it simply provides for you to know how much you're using for each of your devices in the home. What you'll be able to then understand is what changed month to month. So you can see that the water heater went up month to month, and other usage also. Cooling was the big change month over month as well. This information is available because of the smart meters, and because we put engineering algorithms against the 15-minute data. So there's no device level information in the home. There's no device capture in the home, but, rather, we're backing that out by looking at the fingerprints of the different appliances. That's one of the benefits of smart meters and the smart grid going forward.

I don't want to get into this, but we do have a prepaid product. We can talk about that maybe offline and talk about the benefits of that, but, again, I would say that customers are finding this very attractive. Some customers are finding this very attractive for their specific needs.

Let me just go to the final wrap-up page, and we'll close there. So what do we think we need? We need competitive retail markets. We need well-functioning wholesale markets. We need access to data and smart meters. With that, I think we'll change the conversation, and we'll finally create engaged consumers in a way that we've never had before. People talk about our industry as being a low engagement product, a low engagement category. I think the reality is that that's because we haven't given consumers control up until this point in time. It makes absolutely perfect sense for them to be not engaged. If they can't control it, and they find out in September what they did in August, why would they spend any time on it? I think we finally have a world where we can give all consumers, not just big consumers, but every consumer, information and technology that allows them to bring their signals to the market.

And I guess I would end by talking about mixed signals. I think, as we look across this industry with all the capital that people are asking to spend, if we don't first start by letting consumers understand the real price of their choices, how can we create the right signals through regulatory processes to spend billions of dollars? With that, I'll end. Thank you.

Question: In your fixed charges picture, I'm assuming this is a Houston customer, but maybe it's not. Can you talk about what you see? On the chart you just showed with the dial, can you talk about what you see in the fixed charges category, both for a residential customer and for C&I customers and clarify that a little bit? Because I think that's an important part of the rate design question that we can talk about more later. But what is in that category? Because it's not insignificant, and I see it growing.

Speaker 4: One of the big things in Texas, in ERCOT, that has happened in the last few years is that the commodity component of a consumer's bill has come down quite a bit. So the part that we can't control are in the "other" category. That's the part that's sort of outside of our control, which is the T&D cost in any kind of other cost that we've sort of created on the regulated utility side.

Questioner: So, I know Texas is a little bit different, but in general, if you could talk about Texas and maybe what you see elsewhere in the country in terms of capacity or resource adequacy charges that are passed onto the customer?

Speaker 4: If we were to take this product to DC or New York, that would not be in the gray section. The gray section is just the T&D, just moving the power from the market down to that meter, if you will. I don't know if I'm answering your question.

Questioner: So where would you put demand charges then? In this picture.

Speaker 4: In Texas, for those who don't know, we build on behalf of the wires company, so all on the wires costs are sort of on our bill. We pay them independently. If we get payment from the customer, we have to pay the wires company. So, if it's a demand charge related to the T&D part, CenterPoint or Oncor, that would be in the gray. There is no demand charge related to capacity. There is no capacity on the generation side that we would see. If we have a customer charge on this presentation, the customer charge that we would have for our care, etc., that would show up against the other component, not in the gray, if that makes sense.

Question: Are you saying that regulated electricity pricing can't be clear or understandable to customers?

Speaker 4: I'm saying that it's been confusing and random. Yes, I'm saying that. Again, I think we could all pull a bill out today, we could pull out a bill for any number of utilities, and I think it wouldn't be this bill. And I think most utilities could do this work if they chose to do it. We had to do it, because, again, all three million of my customers can fire me every single day. When I go to sleep at night, I wake up with starting at zero again every day, and by the grace of God and a lot of good work, they're still with me. But that's the difference, right, with a competitive outcome. What we're showing you is a bill that I think most utilities with smart meter data could generate. This is 15-minute data with algorithms using a fingerprint capacity of each appliance in the home. All of our customers in Texas have access to this tool. We approximate the home if they won't tell us if they have two air conditioners or three air conditioners, two refrigerators, a pool pump or not. If they'll give us that information, it becomes that much more precise.

But my point is, that if you live in one part of Massachusetts, you have a completely different rate design, price design, than you do if you live in another part of Massachusetts. That's what I'm saying, and so we do misalign cost, as I said. We do often change subsidy regimes relatively quickly, as we did in Nevada. It's an industry choice and a state choice. We do often think about fixed costs or sunk costs when I'm not sure they necessarily matter for decision making. So I think that in those regards, it is confusing, and it can be random from consumer to consumer. And I think the bills that we've been providing consumers that have been heavily regulated…(and we have regulations on our bills, too. We send out the bill that's required by the public utility commission of Texas. Now, I have to be very careful because I see two commissioners here from Texas. And I also want to say the 100 free days, that was not a solicitation, because I don't think I gave my PUCT license number, so I'm not soliciting anyone.) But I think, as an industry, we've done that to consumers. I think that we can do better. I think, hopefully, most people would agree that we could do better.

Questioner: Sure, we can all do better, but regulated utility customers get that information as well.

Speaker 4: They get this information?

Questioner: Yes.

Speaker 4: Across the country?

Moderator: I think we're drifting out of clarifying questions. We can have the debate later, though.

Question: I will say, working with our consumer services department, people do not understand their bills at all. No matter how much we've changed, they don't understand it. But my real technical question, was, if you don't put devices on the appliances, how do you tell the customer what they've used? And if you're using some kind of average, don't you still have that customer disconnect? Because I will say Pepco does that, but you put in, "I have a washing machine, I have this, I have that…" but it's still only an average, and I look at it and I say, "I was away, I didn't use the air conditioning," but it still says that on average, that's what I used, so I'm skeptical of it.

Speaker 4: We've been working with a couple of firms out of Austin. Today we've invested in a firm named Panoramic Power, and I didn't really talk about that because we're on the C&I side, but clearly, there, you do see 10 second device level information with a very simple data clip. It clicks onto the device or onto the circuit and harvests power from that circuit and can provide that precision. We feel that while this is more and more accurate, and accurate enough for the purpose of having a conversation and seeing where the low-hanging fruit is, a homeowner that doesn't understand that the air conditioning is running twice as much as the neighbor's air conditioning, I think it begins to get the value. This is the first iteration, but I agree with you, it is an approximation. But it's a start around the data that we have, which is the 15-minute data that comes from the smart grid.

Question: Again, in looking at the same figure here, showing the information about usage customers receive on their bill, I just want to make sure I get it. You're saying that the fixed charges include all the T&D. So the T&D is, roughly, I don't know, 13% of the bill? The reason I'm asking is that when I take the 1137 kWh, and subtract the $11.75 fixed charges from the total charge, you've got sort of $80 for 1100 kilowatt hours, and I'm thinking about prices in Texas, and I'm thinking, do the prices really get that high? Are the wholesale prices in Texas in April through May averaging that much? When I think of T&D (Texas may be different, I understand that), I think of distribution charges on the residential side as being pretty hefty and not being on the order of 10% of the whole thing. And this just looks very high to me for how many dollars per megawatt hour your Texas wholesale electricity costs during the month. So, again, you're the expert, you're in the business. I'm just a bureaucrat, but it's a clarifying question.

Speaker 4: This is a representation of an accurate bill, so other than saying that, I don't know what else to do. I'm happy to provide data.

General discussion.

Question 1: Thank you to all the members of the panel. This is a very interesting discussion about a set of problems that I think are a great challenge for us. Speaker 1, in your presentation, you were quite explicit, you had that chart about the three Rs, and the underlying transactional platform, and that was real energy, reactive power, and reserves, the various kind of categories. And as you know, I agree with you. That's a way of characterizing the fundamentals. Last week or the week before, I can't remember exactly when it was, the Public Service Commission in New York published its order on Reforming the Energy Vision, in which they talked about the new compensation mechanisms and the foundations for those compensation mechanisms, in order to implement this transactional platform in the context of New York, and that document has a lot of interesting things in it, and it talks about the challenges in some of these issues. But one of the things it did not mention was the three Rs. And it sort of skated over that issue and didn't talk about the underlying foundations of the products and the transactional platform. I don't see how to have the kind of incentive-based transactional electricity market on the distributed level without that structure of those underlying three Rs, and I read between the lines enormous resistance to actually doing that, and it seems that what people are really doing is trying to set up PURPA. Help.

Respondent 1: So the question was, "Help." [LAUGHTER] I'm not going to go into the New York report in detail, because I haven't had time to really get into it in detail, so I apologize for that.

Questioner: Stipulate my description as correct.

Respondent 1: OK, I will stipulate your description as correct. I think it is very difficult to see how one does this well in a planning administrative framework where you're attempting to estimate what these different values are. The values are very dynamic, dynamic by time, dynamic by location, dynamic by place. And there are people out there who are trying to do forecasts. So, folks like Integral Analytics, they will do a 10-year forecast where they will look at population growth on your distribution circuits. They'll look at likely EV clusters. They'll look at likely PV penetration. They'll look at traffic patterns, a whole range of things, and they'll overlay that and they'll say, "Well, we think that the expected distributed marginal cost over the 10-year period might be A through double N, and you'll cross these different points on this distribution circuit." Well, maybe that's right, but that's an expected average value over a 10-year period that you know is not going to be accurate much of the time. And if you use that to go out and enter into a contract or a tariff, even at the places that appear to be high value today, A, you're going to be wrong some of the time in terms of even the getting to the average value, and, B, the value is going to vary a lot over that 10-year period for what the specific products are that you need.

So I think that's a problem, and I think the other big problem is that as a regulator, I don't know that I want to be spending time or spending staff time looking circuit by circuit at what the value of DER is at specific locations and specific times. That's a big job, and even having been on a commission that had 350 staff people, I'm not sure we could have handled that job effectively. Now, maybe New York thinks that with 700 people, they can do that, but I think that's a big challenge. And so I think the reality is that you're likely to get those decisions wrong if you don't do something to move to a more market-based way of addressing the problem. That's my recommendation to them: get the prices right, figure out how deeply you need to take the market based upon what the price variations actually look like in a distribution system, and then start down the road of moving in that direction. So that would be my thought about it. I don't know whether that gets us to where we need to go, but that's what the recommendation would be.

Questioner: Just as a follow-up, I think this is extremely important and it goes to the foundations of what we're talking about here. And it's kind of like the distribution version of the LMP story at the wholesale level, which is that if you want to have markets and you want to have people making their own decisions about what they're doing and defining these things, then you have to define their products right, and you have to define the prices right. And if you don't do that, it's going to fail, and it's going to fail badly and be expensive, and then the ratepayers are going to be stuck with the stranded asset cost kind of problem. And at the distribution level, not only do you have the problem of real power, but I take from your report and many of the other things that I've talked to Caramanis about that you really can't get around the fact that voltage really matters and it varies a lot, and so you're into a reactive power world. People don't understand reactive power on the wholesale system. [LAUGHTER] Imagine the distribution customers trying to understand that. We're down into something that is really quite a revolutionary change. Much more revolutionary than I think is coming across in the stories about platforms. And this is not Airbnb. This is not Uber. This is much harder than that.

Respondent 1: Getting the pricing right is a difficult challenge. I mean, when we talk about moving this to the distribution level, this is not only a fundamental change from what we have done in regulation historically. It's also a fundamental change in terms of how we have to operate the power system. In terms of distributed energy, whether it's buildings that are responding dynamically to prices, or whether it's actual generators and microgrids out there that are supplying power to the grid, the dimensionality of that problem is significant. The computational and communication requirements are significant, and the way you control the system is different than what we have done with security constrained dispatch at the bulk power level. There are real questions that have to be answered to do that right. I think we probably do have some window to figure it out, although places like Hawaii are already pushing up against the limits of that. I'm glad to talk more about what I think the hypothesis about how to do that is, but it's a different system. We need to be paying attention to it and to understanding it, but if we don't understand the fact that we have to get prices right, and we don't understand reactive power… I mean, in most distribution systems, the constraints are voltage related. And what we are discovering as we're beginning to track voltage is that voltage is actually much more ragged than what our models had assumed. So we're actually seeing ANSI violations that we didn't know existed, now that we're able to track them. And we're beginning to understand that in some instances, we're utilizing only a fraction of the thermal capacity of our distribution system, because we're not controlling voltage at the edge, and we need to figure out a way to engage either utility devices or customer inverters in an efficient way, which means more than just putting on smart inverters to do that in a way that controls the distribution system. So this is a remarkable change, both in terms of operations and in terms of regulations and prices. So, if we do it right, we will be talking about this for the next decade, and we'll be replicating the work on wholesale market pricing at a distribution level in terms of having that discussion.

Question 2: This question goes to energy consumption data, also known as energy customer usage data. And the question is for the whole panel. Speaker 4 is the only one who really talked specifically about access to data, and I think, Speaker 4, you talked about it in the context of consumers getting access to their own data through smart meters and then being able to react to that, and certainly smart meters are not available to residential customers across the country. They are not easily available where I live in Minnesota.

But I think, even beyond customers accessing their own data and being able to then make decisions based on that, there's a more critical issue that I think is necessary to the goals that all of you set out in your presentations. You talked about better price signals, microgrids, increased building efficiency. But if third parties can't get access to that data, you can't meet those goals. We don't know which energy efficiency programs in buildings are actually working. We put a lot of money towards building efficiency. But how do we evaluate that? And so there's a real problem with third party access to energy consumption data. Cities need those data to establish their building benchmarking programs. Experts and researchers need that data. So, my question to all of you is, to what extent are you working with state PUCs and state legislatures on this issue, having to do with standardization of data and making it available? There's aggregation issues going on, because state PUCs across the country have open dockets on this. Legislatures are dealing with it, and for the most part, I'm concerned that a lot of it's going in the wrong direction. There are a lot of privacy advocates that are participating in these and saying, "No, no, no, we can't make that data available, or we can only make it available with customer consent," as opposed to having a better process of aggregating it or having it be delayed to some extent, so that you don't have the privacy concerns, but that you make that data available so that all of you on the panel can meet the goals that you're putting out. So I'm curious to see to what extent you're participating in these forums where these issues are being discussed and new legislation and policy issues are coming out on them.

Respondent 1: We are active in the markets where we compete. I presented at NARUC just this past winter on this very question of data access around smart meters. There's no doubt that the privacy questions are paramount, and we have to make sure that whoever gets access to the data is thoughtful and maintains the customers' privacy. In Texas, the meter was installed by the utility, by the wire company, by Oncor and CenterPoint. It was done through a Public Utility Commission process. But as a retailer, as the customers' agent into the energy market, if you will, I have access to that data, and I use that data to provide insights back or to help the customer—in the case of commercial customers, help the customer make business decisions around DER resource fit. So we advocate that across the country, but a thousand flowers will bloom, so there's a diverse range of opinion on this question. I think, ultimately, customers deserve their own data at a minimum. It's their information. How that comes out can be made simple or it can be made hard, and there's no reason, in this world of Amazon… I mean, this industry, we're still way behind. So, we advocate for customer data access. I think it's an open question. Will we standardize? I hope we will. I hope more consumers will get information, and more agents of customers then can get information to create products and to find solutions. What Speaker 3 showed was a good example of how somebody with the right level of information can help a customer make a better choice.

Respondent 2: Well, then I'd ask you, Respondent 1, what you get from the utility is 15-minute data?

Respondent 1: In some markets. Not all markets across the country, and in some it's not as easy as other markets.

Respondent 2: The Galvin Electricity Initiative, which was formed over nine years ago, put out a customer bill of rights. You can go to the website. It's still out there, but right now it's a static website, because the Galvin Electricity Initiative has been shut down, or at least it's dormant right now. And it went dormant because Bob Galvin realized he could not move state policy. That was just too difficult to do. And so, he just realized, "I can't invest any more at that level. It's just too hard to push it." But the customer bill of rights talked about how almost every smart meter has two chips in it. It has a radio chip that goes back to the utility feed, and it has a Wi-Fi chip which could go to the customer. The Wi-Fi's been disabled and is not available to the customers almost everywhere in the country right now. And so the Galvin customer bill of rights, said that you need to make that Wi-Fi chip available. You can have, like New York had for a while, a 20-digit secure code that goes to the customer if they want to use it, but at least make it available, because Pecan Street's already shown that if you give the one second or the sub one second data, I can disaggregate every load in the house. I can discern a hair dryer. I can know when the washer's on. But I can also do an energy audit. I can know if the installation's degraded. I can do all these real time. The software capabilities are just becoming unbelievable, in terms of what we can do with that data. The utility can't do anything with the data. They just don't have the capabilities that the private sector does. You've spent all this money for this smart meter, and you're not even using it. And so I think this is one of the customer bill of rights items that needs to be advocated for, but I would say, on the customer advocacy side, that most groups have given up and it's just too hard to fight. I think what I'll call the real customer advocate side from the private sector business side is just not there.

Respondent 3: I think the customer owns the data, and there should be oversight to make sure that that data is protected. We've seen, in some of the deregulated states, less scrupulous actors, and this isn't all of the suppliers and marketers, but unscrupulous actors going door to door, using the telephone, and getting consumers into deals that haven't been advantageous for those consumers. With this type of detailed usage data, the privacy concerns are very real, I think. And should this type of information be distributed in a way that the customer doesn't control, that the utility distribution company doesn't control, one would have to use their imagination to see the type of marketing that would result. I will not refute what you said about the value of such data in helping to improve efficiency, but the control over that data, the release of it, at least with respect to residential customers at a granular level that would allow whatever party to gain access and market as they choose, is a real danger, as far as I can see. The customer's got to stay in control. No release of that data without disclosures and consents, but we need to be careful with it, as the information capabilities associated with the metering technology increases.

Respondent 1: I would say that ownership is far too blunt a model. The question is, who has rights for what purposes to what data? And certainly customers ought to have access to their own usage data. I think that's fine. They ought to be able to authorize third parties to have access to their data, but I think there's a broader set of questions here. And I have some concerns about some of the aggregation rules that we've seen come out of some of the state commissions, in the sense that if you're talking about 15 customers, it's still really easy in some cases to disaggregate that and figure out which customer you're really talking about. And so I think we need to become much more sophisticated about that.

With my utility clients, I talk with them about their stewardship opportunities and responsibilities with respect to the data that they have, both at an individual customer level. But more importantly, they are in a unique position to look at data in aggregate and to create value from that data, both in terms of managing their own system, but also in terms of potentially providing some adjacent services back into the market that could be helpful, both to third parties and to individual customers. And so we're starting, with some of them, to talk about what that might look like and how they cannot just make data available, because I think that probably doesn't get us far enough, but actually think about ways in which they can be constructive with analytics that they can provide that protect the privacy of customer data and still create value for their customers.

Question 3: I want to preface this by saying that we need to leave aside the low income customers for my question. I have to say, I'm fascinated by the notion of getting prices right, on the one hand. And I have worked in the industry for a long time. The problem is complex. It's really tempting to want to get the prices right. I think that paradigm is quite different, and sort of engineering optimality driven, and quite different from getting prices right from a market perspective. On the way here this morning, I went to Starbucks, as a lot of us do, and I picked up my Americano, which costs about the same as I will pay today for my electricity consumption. So I'm a little worried about pushing a pricing methodology to the end use customer that then is supposed to incentivize behavioral shifts that'll save me the foam of soy milk on my Americano.

As resources get more distributed, the interactions between retail level and wholesale level become more important, and, obviously, we need to understand better the cost implications of certain actions, but I wonder whether the right location for charging the right price, even if you can come up with one, whether that location is the end use customer or a competitive retail supplier, who can then decide whether to pass that price signal on in whatever form they want, or carry the risk of not collecting on a cost causation basis, but having the upside of gaining market share, for example. So, that's, I guess, the question—whether, as we develop better prices in terms of being reflective of costs, whether we really want to kind of force those prices down to the end use customer, or whether we want to sort of stop, at least in the markets where that's possible, stop at the retail supplier and let the retail supplier decide what kind of prices get offered to the end use customer.

Respondent 1: Let me take a first crack at that. I think our model, originally, when we started putting advanced metering out, was that we were going to create all these behavioral changes. I don't want to totally discount behavioral change. I think there is a component of that. But I think what we've learned over the time since then is that it's really automation and the development of intelligent devices and systems that will drive most of the value here. And so I'm perfectly happy with giving the price signal to a competitive retail supplier and then letting that competitive retail supplier say to a customer, I'll give you a lower flat rate if you give me X degrees of control over your thermostatically controlled loads, and let me manage that for you within the bandwidth and the service quality standards that you've granted me. I think that's a perfectly OK solution. That's not to say that there may not be customers out there that might not want control, might not want a real time price, plus some option pricing that guarantees some maximum price or bill amount to them. And that's perfectly fine, too. But I think that ultimately, that becomes a matter of individual customer choice, and of what they want. What I'm most concerned about is getting the price signals right, at least to the suppliers, and then seeing where the market goes with that.

Respondent 2: I tend to agree. That's, again, why I mentioned the 100 free days of electricity. I think most great engineers would probably be completely disappointed with the level of economic efficiency from that product. I don't have to worry about that, because I'm not an engineer. In fact, I'm a consumer marketing company. But I do think there are behavioral values. I know we don't want to go into prepay, but a tenth of our customers in Texas are on a very, I think, well-designed consumer friendly prepaid package. Basically, every morning at 8 am, you get a text that says whether you have any money left in your account. If you do, then that's great. If you don't, at 10:00 in the morning…and we tell you, if you're negative, so it's not really prepaid. I would rather call it a daily billed product than prepaid, because that's truly what it is. Because if it's prepaid, that means that as you go to zero, you're disconnected, and most of these systems are not immediately at zero. They're really just a daily billed product. For many consumers, the behavioral adjustment comes at the bill point, not the price point. Prices are interesting, but bills are what drive behavior. I get my September bill for August and I get upset with my children and I tell them we need to not run the air conditioning quite so hard.

So I do think there are behavioral benefits. I also think that the retail industry, if you think about this, we've gone from having to one tariff to five tariffs to now, if you were to ask me how many products I serve for my three million customers, it's more than five in terms of price points and product types in the market.

And so I think there is a balance. For larger customers, clearly, signaling the cost directly makes a lot of sense. I think that for smaller consumers, if you will, residential small business, I think you can create signaling devices, 100 free days of power, free weekends, five cents on peak or 15 cents on peak, five cents off, that I think get to the point that you find a lot of the value. And I do think, though, that the goal, and the goal of having a well-functioning retail market aligned with the wholesale market, is that this industry does have both a utilization problem, because we have a lot of resources that are underutilized, and there are a lot of people that want to put more money into the industry, and I think the core question is that we need to get some level of real signals at the retail level before we make billions and billions and billions of dollars of further investment. So I appreciate that your latte costs more than some people pay for electricity, but I'd also say that one of the lessons we live with as a consumer marketing firm in the energy space is that we can't let a focus group of one, myself, drive our product design. Because what I would buy is completely different than what the other three million people that we serve every day would buy.

Respondent 3: I need to respond. And I'm sorry this doesn't directly speak to your question, but there's a fundamental difference between providing a residential consumer information on a daily basis, or as frequently as possible, on usage and expenditures and all sorts of related information, which can be of great value, and automated and immediate or near immediate disconnection as soon as a credit balance reaches zero. And people who have concerns with respect to prepaid service don't want to confuse the two. So, sure, let's provide customers with this type of information, and maybe some people want to pay extra for that on an optional basis. Maybe it should just be provided to all customers that have a smart meter. But once you start talking about automated disconnect with the exhaustion of that credit balance, we're in different territory. And one is credit and collections, one is information. So you don't need to have automated disconnect in order to provide consumers with good information.

Respondent 4: I think your comment gets right to the crux of what is a common misconception, which is that real time data and price signals are for the customer. They're not. They're for the private sector. And there's billions of dollars of investment ready to come into this marketplace if it would open up. And I think the lack of price signals and the lack of the real time data is keeping the market out. And I think commissions should really think about that. This is really about sending a price signal to the private sector, who will then invent all kinds of cool devices. Look at the Nest thermostat. You drive away from your house and your air conditioner turns off. You drive back, it turns on. I mean we've just hit the tip of the iceberg as to what the innovation is that's coming. When you think about connecting the internet with Wi-Fi devices with intelligent software, the sky's the limit, and the utilities are just not in a position to be able to invent and design at the pace that can happen here. So I think all this is about getting the price signal in the data to the private sector.

Question 4:

I guess we have the same privacy issues with data in all aspects of our life right now, and I personally don't think the electricity scenario is unique, in the context of being on the internet and entities having access to your data there, or using your phone and entities having access to that data, too. So I think it doesn't solve the problem, but it's a universal issue, and there are probably, hopefully, some universal solutions being talked about for those challenges for the individual consumer. So I encourage folks that are thinking about that to think not just from an electricity perspective, but in terms of all the other aspects of our lives that are impacted by communication and data.

My question is more specific to rate design and customers. We talked a lot about residential customers today, but there's a large group of what I would call medium size customers around the US who typically get lost in these conversations about price signals and rate design. For example, this morning I got an email from one of our salespeople in New York who is working with a rather large customer, not an industrial size customer, but a large banking institution. They said, "Can you explain the PSE general service class two in National Grid's territory? What makes up the ancillary service charges? How often are they going to change?" Customers like that, that are thinking about options for solar or retail choice or storage or demand response, have challenges understanding their rates and their bill. And so my question is, are we moving towards a more simple representation of customer charges, while we get more complex at the same time? And which is the better outcome to encourage customer behavior? I mean, this is a sophisticated customer that today doesn't understand an electricity bill in New York.

Respondent 1: Well, did you have a good answer for your customer? [LAUGHTER]

Questioner: I got to go do like five hours of work to figure out the answer.

Respondent 1: I think I said something about how regulated prices may be confusing and random. The key for me, I think, is just certainty. I think that's what customers want, and that was my comment, really, about cases like Nevada, again, for a good public policy reason and good other business reasons changing their net metering policies 180 degrees (or at least from afar, it looks that way), enough that large solar companies would just walk away from a market. It seems that that level of change just doesn't work. In terms of whether I think that this industry can simplify its rate design, I've never been a regulator, nor have I worked in a utility. So I'm probably not qualified to answer that question.

Respondent 2: So you're going to force me to try to come up with an answer. [LAUGHTER] I don't know that I do have a good answer for your customer. Rate design is something that gets decided utility by utility, state by state. I don't really know of any movement towards standardization in this area. As a commissioner, what happens is you get a case filed, and you get parties who take positions on these rate design questions. You can maybe encourage your utilities to try to be more consistent, but this is going to happen on a case by case basis. In some of these cases, at least if you're a regulator, you hope that there's maybe some stipulation and recommended settlement on some of these issues. So it gets even worse, in that it's not necessarily principled, it's what the parties happen to agree to, and that comes with some force behind it, because if you change the stipulation in some way, you're reopening up potentially the whole case to litigation. So it's messy, and I don't have a good answer for you. I wish I did.

Respondent 3 Let me add. You've picked a rate that's probably the most complicated rate in the entire country.

Questioner: OK, fair enough.

Respondent 3: The PLC 2 really is off the charts.

Questioner: I guess rate design is one thing, and customers don't necessarily need to understand rate design, but they do need to understand what is on their bill. And even as a sophisticated customer that has a solar system, my bill is not very straightforward. It says I'm a central CHP customer in Massachusetts. It shows transmission, generation and distribution, and it says I'm a CHP customer, which I am not. I understand what they're talking about. It doesn't have any of the bells and whistles the previous speaker was talking about. I get an Opower thing once a quarter that shows how I am relative to my neighbors, which is great, because I always look great relative to my neighbors. But, I guess, for commercial customers that are thinking about being more efficient and all the things we've talked about for years and years and years, do you think that the transformation is towards a simpler representation of that rate design? Or is it just going to get more complex for them?

Respondent 2: I think you could, in competitive states, see competitive offers that simplified some of those charges. I think that's a possibility. I will tell you one other thing that I advocated for as a commissioner, but that didn't get very far, was to require utilities to develop bill comparison applications, so that a customer could look at their load profile and see how it would work under different options. It would require some more sophistication than what the utilities were willing to do when we asked them to do it.

Respondent 1: I don't know that we'll ever be simpler. To me the question is certainty. Speaker 3 hit on that point when he said that under one model, this is a six-year payback and in another model, it's a four-year payback. Businesses that are looking at a decarbonizing world, a distributed world, that want to have a resilient enterprise are sitting here saying, "Well, should I do this or not?" And I think you could put that question to a lot of bright rate utility experts, and they could say, "I can't commit that over the next 10 years, this is what your cost structure will look like." So, OK, well, then I'm going to add uncertainty, because my CFO is always going to add a fudge factor, and I'm not going to make that investment in that distributed energy source. That investment might make my business more resilient, my economy more sustainable, but you know what, it doesn't pass my threshold. It sounded like that was what your customers are grappling with. Certainty it is the biggest thing. If you're going to set a rate, set it. Leave it. Many years ago, my understanding was, people liked volumetric distribution rates. For some reason today, we don't like volumetric delivery distribution rates. We'd rather have fixed rates. At least, that's the way the industry seems to be going. I don't know if that's because there's no economic growth, and so there's no upside, but, again, I think certainty would be the most important thing.

Question 5: There was an interesting comment a couple of minutes ago that getting the pricing right will bring all kinds of new capital and business models into the business. I think exactly the opposite is true. I think we have all kinds of business models and capital flowing into the industry now because prices are wrong, and people are taking advantage of arbitrage. But we could probably argue that all day.

We do have a problem with subsidies in current rates. And I know exactly what it is in the four states we serve in the Southeast. We are subsidizing low usage customers, not necessarily low income customers, although a lot of low usage customers do happen to be low income. The subsidy is coming from high usage customers or high income customers. And we know, because we've tried in almost every rate case we've been in, that getting rid of those subsidies is very hard, so I wanted to present another thought and get your reaction. When we went through this in the telecomm industry, what we did is we added a line item to everybody's bill, which said, "universal service." And I wonder if maybe it's time to make this low usage or low income subsidy explicit, have a universal service fund on the bills and directly subsidize lower income customers, allowing us to get the rest of the rate structure right. Do you have any reaction to that?

Respondent 1: Well, I think close to half the states right now have investor-owned utilities that offer some sort of discounted rate. The structures are very different, the scope is very different, but we're part of the way there. For those remaining states, I would certainly support what you're suggesting. There are very difficult politics associated with that, obviously, but yes, equity is a concern, particularly in this transitional period that we're in, where there will be lots of new capital investment and changes in rate design. Such a backstop, really, would be nice. And if you work in some states that don't have such programs right now and would like to partner up on that, we'd be with you. I can tell you that.

Questioner: I'm not really talking about low income rates, because that just further skews the whole rate structure. I'm talking about taking the whole issue out of rates--make it a tax, make it a universal service fee, and make that subsidy explicit to help low income customers, but then change the rest of the rate structure so you're giving the right price signals to everyone else.

Respondent 1: That's a longer conversation. I think ratepayer funded bill payment assistance, arrearage management, robust regulatory consumer protections that really do ultimately have bearing on everyone's rates, that those are good and reliable structures for helping to address equity issues. So it's partly a philosophical question and a philosophical difference, perhaps, but it also has to do, from an advocate's perspective, with the reliability of a revenue stream that's going to be dedicated for that purpose. And when you start looking at annual legislative appropriations (unless you're in a state like Ohio that has had a couple of decades now of over $100 million allocated for this, but I think that's an outlier) the reliability of that revenue stream would be in question.

So, again, I'm giving you my biased advocate's response, but backing up just a little bit very quickly, if you look at the residential energy consumption survey data, and, admittedly, this isn't service territory by service territory, or in some cases even state by state, but your comment about the relationship between usage and income, analysis can bring some useful insights there. I think there are many in the fixed charge discussion on the residential side that say "Well, low volume consumers tend to be higher income consumers." And the data just shows the exact opposite. Folks who are eligible to participate in a low income assistance program, on average, use less than their higher income counterparts. Similarly, elders use less than their younger counterparts. And we don't talk much about race in forums like this, but you can also see that African American headed households and Latino headed households, on average, use less than their counterparts. So, in looking at some of these equity issues, when we're having rate design discussions and talking about whether to increase those fixed charges, as opposed to keeping cost recovery in the volumetric charges to the greatest extent possible, some of these findings really are important, I would suggest.

Question 6: Thanks. I've never answered one of the solicitations I've gotten from a retail provider, but after seeing the bill that I could be getting, I think I'm going to sign up for Direct Energy. [LAUGHTER]

I do think that it would be really nice, as a consumer who doesn't really have the time, to be able to go in and have a bill that says, "Hey, you need to change your refrigerator," or something as simple as that, and you make money. I would definitely respond to that kind of pricing.

But my question is actually about capacity markets, which I was surprised didn't come up here at all. So, I guess PJM just spent about $6 billion in capacity markets. People think of the theory behind that as, "We need 'missing money' for generators," but it's really to ensure that the market clears at all times, because there's supposedly a market failure.

There is a market failure, which is the lack of real time prices. If prices could just go up until customers voluntarily went off, you wouldn't need the $6 billion in capacity payments at all, and you could probably buy a lot of smart meters for customers with that. And the question I have is whether this technology would be feasible to let businesses use it to be more efficient about demand response, and you could have real time prices that actually reflect the price of keeping the lights on as well as the marginal cost of energy in any given instance, and I'm curious if Texas is doing something around that in order to avoid the need for capacity markets.

Respondent 1: I'll take a crack at that, going back to some of my work when I was helping Midwest ISO think about these questions many years ago. And, ultimately, what we said was that you need some sort of potential interruption price at which the customer would agree to get off the market in a real scarcity situation, combined with the ability to have scarcity pricing, so that you're no longer stopping the energy price at $1,000, and you actually can have customers see the price signal, and that gives you the assurance that you would clear the market, because you would have some interruption guarantee price at which customers would agree to leave the market. That's a simple answer. My own view is that we ought to be doing a lot more in terms of the energy markets and scarcity pricing and less in terms of capacity markets than what we do today, because we'll get more granular, more efficient price signals by doing that. But I know others have different views.

Respondent 2: So, from a consumer marketing, business marketing, point of view, we do have demand response programs that try to provide appropriate signals. And we've seen a little more response in ERCOT, although energy prices are relatively contained. We had a program last summer, and it was amazing, 25,000 people were posting pictures on their social media sites of their thermostat set at 78 degrees. This year we've redirected the program to focus on the super peak period, which clearly then allows us to give a larger refund bill credit. It doesn't address the capacity market question specifically. I think that question is sort of you either are for capacity markets or you're not for capacity markets. It's a philosophical question in many regards. But I do think that the market and behavioral response, as well as automated response, will become much more active in signaling where the specific market need is, finding those hours where you, in fact, see demonstration of higher prices which would indicate sort of more constrained capacity situation.

Look at Illinois, for example. Residential customers now, low income customers especially, have gotten a huge break because they have the advanced meters now, and in Chicago now, Com Ed is charging the capacity charge, based on your peak. So, now, that capacity charge is much less for the low income customers in Chicago. So I think as a price signal, it's fairly effective, because it's one of the few demand price signals, and right now, on the bills, there aren't that many. In Texas, you don't have that, so you don't have many demand price signals in Texas right now. There is no capacity market, I don't think.

Respondent 1: There is no capacity market, but the volatility of the market does provide signals back to us, that we then translate down to consumers, be they large or small. Large customers are seeing the volatility, or deciding to sort of take that off the table, and smaller consumers see that in their forward price. If they come to me for a three-year price, it's going to approximate the risk in how the market operates. So, it does translate down into the consumer level, but it's not as transparent as PJM's capacity or ISO New England's capacity markets.

Question 7: When talking about New York and the distributed energy resources and the connection to this DLMP, I think it makes sense that the DLMP gives you a really efficient price signal for real power, for reactive power, and for reserves, but you also made the point that you're not sure it would really be worth the cost of implementing such a complex pricing system and then having to have the oversight for it. So I wanted to ask the question about the scale of the impact. I looked at what New York put out a week or so ago, with this REV, and my sense was that the thing they have in mind is that something like this would trigger a huge transition to a large decentralized power supply system and the reduction of traditional big central station power plants and grids. And my question is, do you see this, knowing the economics of distributed generation? The anecdote they provided was a load pocket. I'm skeptical of the idea this would unleash the kind of result they want. So I was interested in your sense on that.

Respondent 1: So, again, without having read the details of the New York report, my sense is that the winning DER in the short run is flexible demand. It's these commercial buildings that can act as batteries, for example. There will be locations where either existing installed generation or, in some cases, new installations of something, because of a particular locational issue, will likely be cost effective. Now, maybe storage and PV becomes much cheaper in a few years, but I don't see, in the near term, replacing the need for central station generation. But I do see much less growth in demand as demand becomes more flexible, and that flexible demand playing a much larger role as a DER.

Questioner: Largely, the demand side not the supply side.

Respondent 1: I think limited, targeted areas where pricing tells you that the supply side can make sense, or in places…there are certainly a lot of buildings in New York that have existing generators that might operate in some hours, because for insurance or other purposes they have to have those generators. I think those will come into play as well. You'll also perhaps see some focus there on reliability and resilience, and that will bring some more resources into the market.

Question 8: I understood, after I got a fair way into the report, that LMP plus D was fundamentally different from DLMP. And that was sort of an epiphany when I finally got there. [LAUGHTER] It wasn't just sort of moving the letters around, like the RTOs like to do with everything else, but it does seem that DLMP is a short run concept, based on the three Rs, whereas LMP plus D is a long run planning concept. So my clarification question is, is it possible that, to be completely correct, the right calculation would be DLMP plus D, to combine both the short run and the long run cost elements all together? So, that is my clarifying question.

Let me just go ahead and just ask my second question, which is a little bit more substantive, and that has to do with the phenomenon being observed in part because the duck curve in California and the proliferation of distributed energy resources there, primarily rooftop PV. It appears as if billions of dollars of new costs are being incurred for battery storage and for distribution system reinforcements to accommodate this explosion, as it was called earlier, of rooftop PVs. So if that is a fair observation, is it possible that the "D" in "LMP plus D" is actually a negative number, in the sense that distribution system costs are actually increasing once you get to a certain penetration level of distributed energy resources?

Respondent 1: Let me try to answer both of those. First of all, the clarifying question. The way I would look at that is that there will be instances in which a distribution utility, in its role of having responsibility for maintaining and operating the distribution system, may want to add a distributed resource rather than, for example, build a new substation. And the way I would approach that is, first of all, you would want to have that reflected in the DLMP initially, but there may be instances in which the utility would want to enter into a contract for resources at a particular location to address that kind of a distribution need. My own personal preference, and this is certainly a question that you could take different positions on, is that the utility should think about engaging in a series of procurements for option contracts that would allow the utility to operate that resource just when and where it needed it, rather than a tariff or a long-term contract that meant that that resource was going to operate all the time, whether it was needed or not. So, a kind of modified version of your DLMP plus D, with a limited second D.

On your second question, D certainly can be negative. One of the things that I've seen in some modeling is that even where you have a positive DLMP that could be resolved by a DER, that that gets resolved relatively quickly, and that additional DER in that location, in fact, simply may increase costs rather than reduce costs. So, just because you're got a place where DLMP is high today doesn't mean that you can just dump lots and lots of DER into that location without inverting the price curve.

Respondent 2: I'll just add that if you look at Chattanooga and Naperville, two municipal utilities, they have completely deployed a self-healing distribution system, and they've done that without raising rates. So, they built, over the last 15 years, that into their design, which you call the fourth D, knowing that the solar's coming, that the customers are going to have stores, they're going to have assets. They built out their distribution system in anticipation of that. It also improved their reliability, but they killed two birds with one stone, so it was just built in in design. So I agree, if the utility has not planned for the future that California's going to, then the D is going to cost more. But if they've planned, and it's part of their investment strategy, they can do it within their existing rates. It just needs to be planned for, and I just don't think it's been planned for, which is causing the D to be more. But Chattanooga and Naperville both prove it doesn't have to be more.

Question 9: Thanks. I'm actually intrigued by the earlier comment about the cost of electricity in comparison with the Americano with the whipped soy cream on top. What constitutes the bill? It's price times quantity. And so, why can't we start showing prices, the right prices, the three Rs, plus the DLMP plus D, or looking at the infrastructure costs and getting those prices "right," and I have opinions on megawatt mile type methodologies to get that right.

Why can't we show that, and then present, a menu of options with all of that information to customers? What would be the objection on the consumer side or the retail choice side about the menu of options? And it sounds like Direct Energy is doing that, providing a menu of options. And how does that work, and what would be the consumer response to that?

And then, finally, the last question I have has to do with municipalities and the vision of building that infrastructure. I live in a town that's probably gone from one of the best municipal utilities to the worst in this period of 10 years. Gainesville Regional Utilities. And we chased off all the institutional knowledge. We had the first solar feed-in tariff, which was actually very regressive, robbing the poor and giving to the rich, and then building a biomass power plant, which actually leads to more CO2 emissions rather than less, because you have to drive big diesel trucks around to gather all the wood waste in order to bring it to the power plant. So why would I want to trust the municipal utility or the municipality to undertake all of that, given such a poor record? And not just in Gainesville, but in other places, too?

Respondent 1: I was proposing a completely state-run system, versus a city and state working together. So, I agree, either can go south for a number of different reasons, but without any local representation, I just think there's something missing, that's all. That's not a predictor of it coming out well. There are many cities that aren't Detroit that aren't being run very well at all and are in big trouble. Chicago right now is in deep trouble.

That's not to say it's, by itself, going to work. I think the state, the utility, and the city have to work together closely.

Respondent 2: I just go back to the "P times Q" bill question. Again, when I say bill size matters, having run the Texas business for Direct Energy, there is no cue. If I walked up to a consumer and said, “What’s a kilowatt hour?” they would look at me like I’m from Mars. There is $25 from my refrigerator, so I have refrigeration that costs me $25. So there’s a P and a Q embedded within that.

So based on our experience working with consumers across the country, they have a psychic understanding of what their bill in September should look like. It’s $300. When it’s $400, that’s a problem. I think where I would go is to a system where the Q and the P in the line item, the amount of detail that you put there, gets intermediated by someone like Direct Energy. That’s kind of how we would see the market. That’s the most efficient way, I think, to bring that signal down, because we’ll figure out the appropriateness or the balance in terms of how detailed do we make things? Our business customers will want to see every single line item that we have to allocate out to them. Households, what they want to see is something like, “I spent $22 on refrigeration.”

Questioner: But in terms of the menu of options that you provide, you have more than one type of rate. You offer different rates, and people can choose. Has that been a good experience?

Respondent 2: I think it’s been a wonderful experience. [LAUGHTER] But I don’t know how we do it without having everyone make a choice.

Question 9: I want to share a little information about making the subsidy explicit. I’d be happy to share it. We have redone our low income rates in the districts. We only regulate distribution rates, and we have a specific surcharge that everybody pays, and it’s designated as the low income subsidy surcharge. Everybody except the people in the low income program pay it. But we also, in order to support customer choice, moved the discount totally onto the distribution rate, and it is a volumetric rate, so the low income customer now gets billed the same rate as everybody else, and then on their bill, there’s an explicit credit showing how much they’re actually getting as a subsidy. So it’s explicit, to the other customers who are paying for the subsidy and also now for the first time explicit to the low income customer—the fact that that’s the subsidy they’re getting and it’s equal to the entire distribution rate. That distribution is free. So, everybody else is paying for it. And that was the only way you could do it to have choice, so that they could choose.

But I really wanted to go back to the title of this session, which is “Retail Rates and Price Signals.” And when we talk about retail rates, you’ve got supply and you’ve got distribution, and most of the discussion has been on the supply, the commodity, which does have a time variant value to it. It’s more expensive to produce energy at a certain time of day, at certain constrained times, at certain times of the year, etc. So there’s a price signal there. But all we regulate is distribution. If you’re doing performance based distribution rates, what kind of price signals, what kind of cost variation is there in a distribution system that’s meaningful enough to the income stream, or the operation of the distribution system, or to the customer, to make a difference in dynamic pricing? Does it have a role there at all? Or are we just spinning our wheels, saying it can’t be done?

Respondent 1: I’ll answer that at two different levels. One has to do with going back to the discussion of DLMP, where you saw the differences in the delivered cost at different points in the distribution circuits for energy supply. The differences in those components are marginal losses within the distribution system, which can be substantial, depending on where you are in the distribution system and constraints within the distribution system, which, again, are largely voltage related constraints. You could do some grid edge volt var control, which would open up many of those constraints and enable greater utilization of distribution and potentially address some of that, but that’s a significant component. There are also issues with impacts on the life of distribution equipment and how you utilize that equipment. And those things all could be factored in to a delivery charge that would reflect the difference in DLMP value from the substation LMP to various locations on the distribution system, and in some instances might be significant.

And so, when I said that we ought to be looking at factually what does that variation actually look like on individual systems, the data I showed you was a model of an illustrative 800 bus radial system. I mean, this is a place where we ought to do analysis. We ought to see what the variation looks like on real distribution circuits, and my guess is that it's probably going to be significant, and we'll probably make the decision, or this decision would probably be justified, to take DLMPs to some depth within the distribution system.

But I start by saying, let's look at the data, and then we can make that decision, because, going to the point that was mentioned earlier, there is some cost to setting up the software to do all this. It's not necessarily prohibitive, but I would want to look at the price variations before ipso facto saying that this needs to go all the way down to the transformer or the customer meter throughout the distribution system. So that's a factual question. So that's sort of layer number one.

Layer number two is, how do you recover the remaining charges that are fixed that are unrelated to or in excess of what marginal costs are? What I would say is that you have a great deal of flexibility here. I go back to the principle that I want to minimize the distortion of economic market participant behavior. There are a couple of factors that weigh on this. Where I might come down might be different if we had a good carbon price, because that's certainly an externality that doesn't get well reflected, and I think you can have a debate about whether or not that should be reflected in any variable component, which has pluses and minuses to it. Because you still could be disincenting some valuable behavior if you put it in the variable component, but at least you could have that discussion. Other than that, I would go back to saying, well, let's try to allocate cost in a way which minimizes the distortions in market behavior, which means that you're going to allocate more cost to things that have elements that are less price elastic, which might suggest putting more things in customer charges than we do today. When I was on the commission in Ohio, we at least moved in the direction of straight fixed variable charges, and despite my invitation to the consumer advocate to introduce something on environmental externalities, I was never able to get them to put something on that in the record so that we could actually have that other discussion.

Respondent 2: Let me just say, because my general counsel would ask me to, that the answers that have been given to that question, as far as they may impact the case before us, will not be part of my consideration of the case, because they're not in the record.

Question 10: In New York, they're chasing distributed energy, and in California, the distributed energy is chasing us, and so we're at different points on the scale with that, and so what we're trying to do is take the known, which is the transmission and distribution costs that have been really well formulated, and now we're trying to drill down into, "What does it mean for D? What are the costs of D?" And it's really a regulatory decision at some point, because there are societal benefits as well.

So I'll just say that if you're interested in more reading, more research, morethansmart.org is a California website where there's a whole bunch of research and findings. And I can't say we really know yet. We aren't "more than smart," we're trying to get smart, but if anyone's got any questions…

Question 11: I’ll try to make this sort of a wrap-up story, but my comment is motivated by the latte problem here. You can send good prices to customers, and they can go home, and they can spend all day watching their meter and do the right thing, and that’ll work. Most customers that I know don’t want to do that. You can send good prices to the devices, and have that process automated, and that’ll work. You can send good prices to a third party, and the third party can go cut a deal with the customers, and that’ll probably work. What you can’t do is send bad prices to everyone and hope that somehow the transactive platform is going to save you all these costs. All you’re going to do is create regulatory arbitrage and transfers of subsidies, and they’re going to be counteracting each other to no benefit. We’ll just have higher costs. So the promise of this distributed energy revolution and really lowering the cost of the system really does depend on somebody seeing those real prices someplace in that system. That doesn’t go away.

Session Three.
Clean Energy Revolution or Evolution: The Cost of Renewables

The cost of renewable energy has been declining, rapidly. The improvements have been enormous. The controversy remains not over whether there has been a substantial cost improvement but whether the cost reduction is enough to turn the corner on the economics of meeting the challenges of climate change. The debate has major implications for a policy choice between wide scale subsidies for deployment of existing technologies versus substantial increased expenditures on R&D to develop breakthroughs that can be deployed in the future. The views range from "[o]ne popularized myth about [Renewable Electricity] is that it is simply too expensive," (NREL) to "[t]he cost of renewables has been falling. But not fast enough." (Global Apollo Programme). Differences in the estimates of the cost of renewables are at the core of the analysis of options under of the Clean Power Program. The Energy Information Administration issued a recent report defending its higher estimates of the cost of renewables against a continuing series of critiques. What are the debates and sources of differences in the estimates of the cost of renewables? How do regional variations affect the picture? What are the trends in costs? What does this imply for the appropriate subsidy policies for deployment and learning by doing? How important is it to expand on the R&D budget and focus on major breakthroughs rather than incremental improvements? Is the revolution already here, or as Bill Gates says "we need an energy miracle."

Moderator: We have a very exciting panel this morning. I thought just to make sure that everybody was awake and engaged I would throw out some little quiz. We are in an academic setting, after all. I have some statistics that I was going to do a little reality check with people on. So, based on some EIA data (which we'll hear more about in a minute), the U.S. is expected to add 26 gigawatts of utility scale generation in 2016. And, just by a show of hands, how many people think that if we're just talking about utility scale solar and wind, it will be more than half or less than half of that 26 gigawatts? How many think it will be less? All right. So this group is already pretty good, because it definitely is more than half, 16.3 gigawatts is expected to be solar and wind. And the follow up question is, how many people think of that more will be solar or more will be wind? So how many think more will be utility scale solar? How many think it will be wind? OK. It's actually predicted to be 9.5 gigawatts of solar and 6.8 gigawatts of wind. So for the first time… So if California is at the top of the investment in utility scale solar, how many people think that North Carolina, Nevada, Texas or Georgia is second on the list? So how many people think North Carolina is second on the list of utility scale investment for solar for next year? How many people think Nevada? How many people think Texas? And how many people think Georgia? It's actually predicted to be North Carolina, which I thought was really interesting. I would not have been right on that one if I hadn't looked it up.

So here's another fact which I also thought was really interesting. The DOE SunShot Program has a target price for utility scale PV solar installations in 2020. So, if your choice was $3.00, $2.00 or $1.00, how many people think the target is $3.00 per watt? How many people think $2.00? How many people think a dollar? And the dollar has it. That's the projection, and there's some recent research from the industry that suggests they are actually going to make that target. So I thought that was really interesting, too, because I wouldn't had guessed that.

And I'm just going to give you guys one more, because this I also thought was interesting. There's one state that recently vetoed a bill that would raise the mandatory RPS standard in that state. How many people think that was Kansas, Maryland or Colorado? So, Kansas, how many people think it was Kansas recently vetoed an increase in the RPS? Maryland? And Colorado? And it was Maryland. With that, it is expected to be overridden when the legislation comes back. But I still thought it was really interesting, because you think of the middle Atlantic as kind of where a lot of this cool stuff's going on.

So there's lots more of that kind of really interesting information and facts that are under discussion right now, and we have a really outstanding panel to frame the issues, and I'm sure we'll have a good robust discussion about these topics.

Speaker 1.
Thank you. That was a great way to start. I'd also like to thank Bill Hogan for the invitation to join you.

I'm going to talk about analysis from the EIA, the statistical and analytical agency within the Department of Energy that provides independent and impartial data and analysis. Unlike FERC, the EIA is not an independent agency, even though its work is independent. The EIA doesn't take positions on policy issues, and by law the EIA stuff comes out without prior review or approval of the Department or other Federal agencies, so my comments don't necessarily reflect their views.

To start with my key takeaways, first, the EIA really cares about this a lot, that's the first point. Policies at the state and federal levels have been the main drivers of growth in renewable capacity, so there's a lot of talk about costs.

Costs are definitely changing, and costs are coming down, but policy has been what's driving this in the United States. And, then, looking forward, I think costs do start to play a bigger role, but policy still remains very important, and some of the recent policies, including the recently extended tax credits, then, later on, the Clean Power Plan, are important, but also some reductions in cost are going to drive a lot of renewables into the system.

But there are challenges. And those are slower or no electricity load growth, at least in the U.S. context, and low natural gas prices, which do limit some opportunities. Low natural gas prices cause natural gas to kind of compete with renewables, but these low prices also may provide some headroom for people making decision--if they're worried about ratepayer rebellion, if you're getting some relief from low natural gas prices, there might be an effort to sort of spend that dividend on bringing more renewables in. Which is, again, a policy choice that EIA doesn't get involved in.

Also, you can ignore the fact that the levelized cost of electricity is probably not a very good metric. Avoided cost is much more useful concept, and yet we get all these comparisons about what's cheaper than what, and comparing levelized costs. They might be more relevant in some other context, maybe a more global context.

When it comes to renewed focus on renewables, people who follow the EIA website know that EIA has long produced current estimates and projections for both distributed and utility scale PV and generation. However, until recently the rooftop stuff was only done on an annual basis and without a state by state breakdown. Starting late last year, however, EIA began reporting small scale distributed PV data on a monthly basis with state level detail. So the same level of detail that EIA reports for the utility scale stuff, and in all the tables and all the browsers are now electricity publications. Using some third party operator data and some other information, EIA has actually been able to do a pretty good job getting the distributed generation estimates state by state on a monthly basis. Which is an interesting estimation problem.

EIA also has undertaken a really extensive review of its projections that directly address some criticisms. EIA's interest in renewables has been one of the key motivations for another major effort that we're undertaking to provide near real time hourly data on load, generation, and interchange among the balancing authorities across the United States. So, as people in this group certainly know, for a lot of areas of the country, you have that data, but for a lot of areas of the country (the ones with the traditional model) you don't have it. And we have in fact been collecting that data. One of the challenges of publishing it is working out the publication of near real time data when there may be glitches in reporting. You know, we don't want some senate staffer running into his boss's office saying, "My God, electricity generation dropped 50 percent in the last hour," and that is showing up only because, you know, some of our respondents didn't report. So we have to come up with sort of on the fly methods of providing imputed data for some of the key indicators that we're going to be featuring. But that's going to be coming out shortly for all areas of the country. And the interchange data that is very relevant to the renewables question, especially the wind question, as you look at the generation moving from areas with strong wind to other areas.

And EIA is also engaging in a lot of discussions with others. So, you know, there's much talk about lower renewable costs, and renewable costs, especially for solar, have been indeed coming down. But policy has really been critical in driving things. So what this slide shows is simply two different versions of the annual energy outlook 2009. And this quote in the box on the slide…It's a pretty nasty quote [about the inaccuracy of government energy forecasts]. It happened to appear on a morning when I had testimony for the House Committee regarding EIA's analysis of the Clean Power Plan. You know, I don't want to take a Trump-type approach to the criticism from the media, but I do think [LAUGHTER] that there are good reasons why the publication that made this quote is called *Politico* rather than *Analytico*. [LAUGHTER]

So let's just leave it there. But those familiar with the EIA's long term projections know that our reference case reflects current laws and policies. And the EIA typically puts out its *Annual Energy Outlook* in the fall of the year before the date on it. And that lower line, we call "AEO 2009 pre-ARRA (American Reinvestment and Recovery Act)." So that lower line shows the projection we had for wind in the AEO 2009. And we didn't have much, because the production tax credit was supposed to expire, so we built the projection around no production tax credit beyond 2008. And the quote in the box (from *Politico*) can be summarized as saying, "Geez, these people are so stupid that they have virtually flat wind, and wind has actually grown tremendously, and grew to 66 gigawatts in 2014."

And because we viewed ARRA as such an important piece of legislation, when ARRA came out, which was in February, 2009, we said, "Gee, we've got to put out an updated *Annual Energy Outlook* that reflects that policy. And that's that brown line at the top. There are the same underlying costs of renewables in the projection. But the projection reflects a different set of policies related to production task credits, loan guarantees, and other things. And, you know, it's just like a stopped clock that is right twice a day. It turns out that the post ARRA projection in terms of 2014 projected wind capacity happened to be pretty much on the button at about 66 gigawatts at the end of 2014. So, again, policy really matters a lot in looking at what happens with some of these things.

Things have really changed a lot in the U.S. In the 50's, when I was growing up, electricity growth was almost 10 percent a year. And I remember playing in New York City, where I grew up, and ConEd was constantly digging up the street. And they had these signs, "Dig We Must." [LAUGHTER] It sounds like Yoda, you know. Yoda stole from ConEd. [LAUGHTER] But it really has slowed down a lot since that time, and the factors driving the trend are things like slower population growth, near market saturation, improving efficiency, shifts in the economy… And we expect that stuff to continue, or some of it to continue.

I'll finish by looking at a very robust program of further efficiency standards that are going into place, and absent a very rapid introduction of some new electricity using devices, a sharp rebound in electricity demand growth ain't coming, in our view. And so how does that relate to the topic at hand? Well, one very important factor affecting the competitiveness of different fuels is whether we're in a "new versus new" setting, as occurs when new generation must be built to meet growing load. For example, if electricity use is growing 10 percent a year, you've got to double your generation every seven years. In contrast, a "new versus old" setting is one in which new technologies need to compete against existing capacity--and clearly, in the U.S., there's a lot of existing stuff that you wouldn't necessarily build today, but in terms of running it, it's pretty competitive. For example, a coal plant that nobody would build today for a whole lot of reasons, but running a coal plant is not that expensive.

And so, the bottom line is that, in costs terms, not taking account of externalities, it might seem like existing plants that nobody would ever build today would be very hard to displace. Many people would have said that about nuclear plants. It turns out, I guess, that they're not that hard to displace. So, again, in this kind of new versus old competition, the comparison of the levelized costs, which you see a lot of the investment houses breathlessly reporting, is fairly irrelevant to what should be done.

Of course, in other parts of the world, it might be like it was in the U.S. in the 50's, but in some parts of the world, electricity demand has grown a lot more strongly, and new versus new competition, like we experienced 50 years ago in the United States, is a lot more prominent. And natural gas faces major competition from renewables for fueling new generation, in both developing and developed countries outside of North America (where massive production from shale resources has significantly lowered prices), so the combination of growing load and higher natural gas prices may make renewables relatively more attractive on a pure economic basis, even without considering environmental attributes, in the context of those markets.

So, a very wonderful politician from this area, Tip O'Neill said that all politics are local. Well, obviously, all these other electricity generation costs are local also. You can see this, for example, if you look at the delivered price of coal to electric utilities in different parts of the United States. To a rough approximation, the closer you are to the Powder River Basin, the cheaper coal is, because transport costs are a big part of coal costs. So when you look at the competition between running an existing coal plant and new renewables, the economic cost of running that coal plant is going to vary regionally. And even within regions there's a tremendous amount of variation.

Turning to future projections, you get different projections depending on whether you include the Clean Power Plan. Renewables provided about 13 percent of generation in 2015. Of course, that includes hydro. But the non-hydro renewables provided, roughly speaking, 6.5 percent. We do see tremendous growth in renewables under current laws and policies (including the Clean Power Plan). We have renewable energy growing to 27 percent of total generation with the Clean Power Plan, and growing to 23 percent of generation without the Clean Power Plan. The reason we did the "without" scenario is because of the stay. I should note that hydro isn't growing at all, so if you subtract roughly six or seven percent from the projection, you can see that the non-hydro part of the renewables category is growing tremendously fast. And it's growing tremendously fast at the front end, really driven by tax credits, to a significant extent. In fact, it's growing so fast at the front end that we expect some decline in natural gas early on, because load is not growing, as we discussed earlier. But, over time, both renewables and natural gas do very well. Coal's generation share, which, even as late as 2005, was half of the generation in the country, falls under 20 percent by 2040 with the Clean Power Plan. And that assumes no extension of the goals of the Clean Power Plan.

Now, renewables are going to be sensitive to exactly how the states choose to implement the Clean Power Plan. This projection happens to be based on mass based implementation. We plan to go back and look at a rate based implementation, which is certainly possible, as well as a mass based implementation with a different allocation of allowances--all kinds of different options. We haven't put those projections out yet. Everything on this cycle should be out by early July.

With the Clean Power Plan, we do expect renewables to surpass coal as a generation source in the late 2020's. Without the Clean Power Plan, coal hangs on a little longer, but renewables still grow dramatically. Renewable growth is not only related to the Clean Power Plan. It's mostly. at the front end, related to tax credits and the states' policies.

Looking in detail at projections for renewable energy, you see tremendous amounts of wind and tremendous amounts of solar growth. You know, people talk about what's happened from 2008 to 2015, but we see really large amounts still coming under the current policy world, less without the Clean Power Plan beyond 2020.

The history of what kinds of capacity have been added in recent years is really kind of fascinating, because the additions really do move around a fair amount. You have this period in which additions are all gas. And we have these coal builds. A coal plant takes a long time to build, so there were a bunch of them that came on in 2008, 2009, 2010…really, all the way up to 2014. And those were plants for which the investment decision was made before the shale revolution. And the effects of the shale revolution took time to filter through.

But we see a lot of solar and wind in our future. Going forward, we do see solar doing quite well in the out years. Wind costs average about 1770 per kW in 2015 dollars, based on 2014 capacity additions. But the cost of wind capacity is wildly different across regions. And obviously the quality of the wind resource is wildly different across regions.

With respect to solar costs, we do see a drop. You'll notice we don't get to the SunShot quiz question answer, but on the other hand we're doing this in AC. And that means two things. One, that means the cost of inverters, and, two, it means the fact that the inverters are not sized to deal with maximum output, because it's not economically reasonable to size the inverters for the maximum output on the summer solstice. So if you take both of those into account, that's part of the difference. But part of the difference is that we're not committed to the SunShot goals. But we do see continuing reductions. We do have learning. We do continue to update. We also see continuing declines in the rooftop area.

Question: Do your projections of growth in solar and wind assume the effects of investment and production tax credits?

Speaker 1: Yes.

Questioner: Have you done the numbers without them?

Speaker 1: No, because we don't second guess what the policy is.

Questioner: It drops off when they expire.

Speaker 1: Right. If you look at our projections, you see a lot of stuff going up to 2022. It's all front loaded, and that's because of the production tax credits. But we do see more solar in particular coming on even without. A point that I wanted to make is that to date it's largely been policy driven. And some of that is policy driven by the Clean Power Plan, which is also a policy, but even without the Clean Power Plan, you can see there's not that much impact on the front end. You still get a lot of solar and wind in the early years with the production tax credits, but you do get somewhat less solar at the back end, and that's because the existing coal plants can run, without the Clean Power Plan.

Question: Do your wind projections include offshore wind?

Speaker 1: In theory, they do. The model has offshore wind in it, but I think there's not significant amounts of offshore wind in this. Offshore wind is not being selected, because, I think, of cost considerations.

Question: This is a technical question. I guess you can only model existing legislation, and executive order type things like signing the Paris Agreement do not feature into what you're modeling out, correct?

Speaker 1: Well, it is tricky. I mean, when President Xi of China says something, in some ways it may be more of a policy than when our President says. Executive orders, we would model. Regulations we certainly model. For example, take something like the phase two standards for heavy duty trucks that have been proposed. If those were final standards, unless they were overturned by a court, we'd include them. So, executive branch actions that the executive branch can actually take, we would include. But, on the other hand, if the executive branch says, "We have a goal of 26 to 28 percent below 2005 levels in 2025," we're not going to say, "Well, that's their goal, so we're just going to do whatever is necessary to get to that goal." I think you get the idea.

Question: If you look at the projections with no Clean Power Plan, do I see that after about 2022 there's really no wind, but the solar continues?

Speaker 1: Right.

Questioner: And if you look at state RPSes, a lot of them have a solar carve out specific solar RPS, so I just wondered if the difference had to do with both the investment tax credit and the production tax credit dropping off.

Speaker 1: Right.

Questioner: And so wind goes away in terms of new production, but solar continues?

Speaker 1: It's a combination of things. One is that the actual existing law and policy is that, while the 30 percent solar ITC goes away, the 10 percent solar ITC is permanent. So, in some sense, solar continues to have tax credits support forever, although not at the 30 percent rate. The other thing is that we do run into issues with where the wind is located, and this is something we have to look at closely. We did not build in here some of the direct DC lines that are under discussion under federal siting authorities--something I'm sure this group is very interested in. And we do have some constraints in the modeling in terms of what proportion within an area of generation can be non-dispatchable resources. (Some people don't like the word "intermittent." I don't really care. You all know what we're talking about.) So the issue for us is, if you have these DC lines, it might be better to count that energy, not at the origin point, in terms of how much non-dispatchable energy you should have, but to count it at the destination point. So we are looking actively at that.

But there are two things. One is the continuation of the solar tax credits. Two is the constraints, I don't know if they're right or wrong, that we have built in on the amount of non-dispatchable electricity. So in wind alley, we're up in the 40's in terms of the percent of total generation coming from wind. And that does start to be a constraint in our framework. But, again, that constraint might be relieved by other things. And with those types of DC lines, you know, there might be more room for wind. But I think that's what's driving it.

Question: I'm trying to understand the price delta of residential being cheaper over the long term than behind the meter commercial.

Speaker 1: They're both behind the meter in those figures.

Speaker 2.

Thank you very, very much for inviting me to this. It's a great honor for me. So, I took Bill's questions very literally, for better or for worse, in preparing my remarks for today. Bill asked, why is it that the costs are all over the place? Why is it that it seems so difficult to get the cost right in estimating renewable energy? The fundamental underlying question is, is it cheap enough already, or do we need a revolution? And if we do need a revolution, presumably, is there a need for a great role for public investment to get us there?

And in developing these materials, it made me reflect a little bit on how we use the term "cost" in thinking about energy policy and planning. And I'm probably consistent with many of the speakers here today. I think we're finding that the notion of the levelized cost of energy is very limited in its usefulness. And that generally the idea of thinking about cost in kind of simplistic, non-spatial, non-temporal terms is perhaps less useful in energy today than it was in years past.

So, first, answering the question about why is it so hard to estimate the cost of renewable energy. To sort of take a page from the history of science, how do people actually do this? There is Lazard Investment Bank, which has, for the last 10 years or so, put out estimates of the levelized cost of energy. So I want to take just a little bit of time to explain why they do this and what their numbers mean, because they have a fair bit of currency in the industry, really among utility players, and in the investment community as well.

Lazard's in the business of basically doing mergers and acquisitions, and they like to be able to say relevant things to utility executives. So, back in the day, about 10 years ago or so, as many of you will remember, there was a lot of controversy over solar costs, and there was a big controversy over how we talk about the cost of solar, the fact that it has different capacity factors used during different parts of the day, et cetera. So they developed this idea of standardizing the notion of the levelized cost of energy in order to be able to have conversations with policy makers and all investors about how cheap solar really is. So they started tracking these costs, and the way they tracked these costs is by rather informally surveying industry participants about things like, how much are your wind projects going for? What's reasonable? Then they developed a very simple project economic model where they can control for the cost of capital, capital structure, cost of O&M, et cetera, et cetera, to some extent, to make the estimates they get from different market participants, and to make apples to apples comparisons.

When they do that there are a few interesting things that come out. I looked at the history. (This is all publicly available information and I'm not representing Lazard, or misrepresenting, hopefully, Lazard in any way.) This is what you find if you go on the internet and look at Lazard's estimates. In the case of wind, the direction is not totally unpredictable. It's downward. It's surprising, perhaps, how big the span of estimates is. That, of course, reflects geographical differences in wind costs. It reflects scale, it reflects a range of things. And it tends to be high. It's sort of consistently rather high compared to what a lot of industry participants would see. But it doesn't look absolutely nuts.

The other side, looking at solar, does look, to my view, absolutely nuts. Why is that? First, just look at utility scale, thin film PV. So, again, we have this levelized cost of energy, which is backing into the price that you would need in order to get a return on capital for a project, for doing thin film solar. So what you see with the costs, is that they decline, and they also converge quite a lot, to the point where the high and low are kind of difficult to discern. On the other hand, really surprisingly, in the case of rooftop PV, contrary to all the things we read in the press, it looks like the costs are increasing pretty noticeably, and the variance between the high and low cost projects actually seems to be increasing.

So what's going on here? Lazard is just kind of dutifully reporting back what they hear from their estimates. So there's nothing nefarious and nothing incompetent, they're just kind of reporting back. I interviewed them about this, and there are a few things going on. First, with the utility scale solar, it's actually quite a competitive market with a lot of visibility in terms of the prices. And there's a relatively large number of players and an increasingly competitive market. And that, combined with technology, leads the prices to go down, and the prices to converge--something that you'd expect in an Economics 101 textbook. Residential PV is a very different critter. Not only is it a much more fragmented market with great differences in terms of insolation and so forth in different parts of the country, but it's much less transparent. Many of the market participants are in the business of maximizing the cost of capital for the rooftop installations, because that's how they make money. They make money by basically getting as much of the tax credit as they can, which is a function of the capital cost of the material. There are also actually very large subsidies and large rents to be gleaned, and they are. And so you see much price convergence, and in many cases as these markets open up, the suppliers take advantage of those subsidies.

Lastly, and more consistent, I think, with kind of the conventional story about what's going on with rooftop solar, by definition or by design, the Lazard model keeps the cost of capital and the capital structure in these projects constant. However, much of the innovation and the cost savings and certainly the consumer appeal in solar has come through using mortgage-like products in selling solar. So from a consumer's standpoint, the cost of solar has come down in many ways in practical terms and in affordability terms. And that's come through financial innovation and changes in the financial structure and ultimately changes in the cost of debt, to the extent that you can actually syndicate the debt associated with the tranches of rooftop solar mortgages that are available. That's not reflected in these numbers, but it is driving some of the market. So I thought it was interesting that there's both a combination of some of the limitations of the model and also some of the fundamentals of the marketplace which are very, very different in those different markets.

Question: What's included in the cost? Is interconnection included? Labor? Are you just talking hardware?

Speaker 2: First of all, I'll very bravely say that these aren't my numbers. But labor is included. O&M is included. Cost of capital is included, et cetera. Interconnection is not included. Again, where I'm coming from is asking what we can say about the way the cost information is gathered, and so forth, as opposed to really defending the numbers per se. The other thing I'll say is that every year Lazard publishes the range of the costs based on their surveys. They also survey people about where they think the price of solar and wind and so forth is going. And those surveys really aren't very good, it turns out, in terms of predicting the future cost of energy. My colleague here does a much better job. At least, that was the case before. So there were very enthusiastic claims made by some of the big players about how costs were going to come down. And in fact they didn't come down nearly as fast in reality as the expectations. So people thought that the price is 2012, for example, was going to be in some ways substantially lower than it actually was. What we're seeing, though, with 2015 and going forward, is that it's actually converging. So the reality is sort of catching up to what the manufacturers are claiming it could be, which is a little bit interesting.

My firm has been involved with Lazard over the last year in developing a levelized cost of storage for the same reason that the levelized cost of energy was developed, and that is that there's a lot of talk among utility executives about what the heck is going on with storage, when is it going to be cheap enough, how does it compare to other resources? And in our case, we spent a lot of time being careful about defining what the use cases are for storage, so that we can try to make an apples to apples comparison. And so we developed 10 different use cases. You can have a lot of use cases, but we're trying to reflect commercial realities the best we can. For each of those use cases we try to be very careful in stipulating the number of cycles, the size of the system, depth of discharge, and so forth.

And there are the things that really drive the cost and that are associated with serving different users, or associated with serving different storage applications. So, anything from serving frequency regulation to behind the meter demand management, et cetera, et cetera. There are different systems that are required. And our experience in doing this is that, even when you try very hard to make apples to apples comparisons, you have loads of trouble in trying to understand the real cost of these things. Why? One is early stage technology. It's by necessity, almost. One has to include non-commercialized technology with commercialized technology, and that creates quite a large range. There are locational differences in costs--installation costs, in particular. The estimates you get necessarily reflect commercial considerations by the folks that are giving you the estimates. And then no matter what you do, somebody's unhappy with these sort of estimates. So a lot of the industry participants said, "You guys are being way too stringent." Other people say that you can't even use a cost notion to describe storage. There's been a lot of comparison about what we use in the denominator. Should it be in dollars per kilowatt, because a lot of these are power applications, or should it be dollars per megawatt hour? We can show the numbers either way. It's division. [LAUGHTER]

But increasingly we see that to really understand storage, there are important network effects that really affect its cost, which gets back to the notion that LCOE really shouldn't be used at home. It shouldn't be used for resource planning. There are much better mechanisms out there to think about those kinds of decisions. I'll return to that a little bit more in a moment.

Turning to the next question, are we there yet? Do we need an energy revolution or not? Based on the LCOE numbers, for better or for worse, I am probably more or less consistent with conventional wisdom in the industry right now. We're pretty darn close on utility scale solar and wind. So what kind of carbon abatement cost would be needed to make the cost equivalent between coal and between coal and natural gas versus these renewable energy or non-carbon energy sources? Comparing new generation to new generation, utility scale solar and wind are actually quite close. These are current costs, and my colleague here will tell us how much wind is going to come down over the next few years. Solar certainly is believed to be have a lot of room to decline. So if the question is, do we need a revolution in renewable energy costs in order to achieve a low carbon future, as stipulated by Paris or some other sort of other versions of what that low carbon world would be, I think our view, from what we understand is, "No." We're pretty darn close, if we're just talking about the cost of renewable energy at utility scale.

And that's even true, to some degree, if we think about rooftop PV, at least with a certain notion of rooftop PV. We worked with one of our clients recently to think about what would happen if we took away current retail-based net energy metering subsidies, and if we think that SREC prices are going to decline as we hit the renewable targets state by state, and if we have a moderate (not SunShot, but more like EIA definition) about how much solar costs going to decline, and if we make some assumptions based on history about how retail electricity prices are going to increase for different customer segments—given all those stipulations, we find that in many states, even with unsubsidized PV, or getting some relatively modest value of solar (similar to the Austin methodology), we think that there is a 10 percent internal rate of return for third party development in these states for rooftop solar.

So what does that mean? We think that developers would do solar projects without subsidies 10 years from now in a large part of the country. For residential and for commercial, and we think there's more availability because of the cost and also because of the capacity factor associated with commercial customers in the commercial sector, as opposed to residential. These numbers might not be right. I saw some people shaking their heads, but it's not that far off, I think. And we can certainly have a longer discussion about this. So we think, even with rooftop, which we don't think is a very effective way to deliver low cost, low carbon energy (in the near term, anyway), compared to some other alternatives (with lots of caveats), even there, it looks like we're getting closer, or close-ish.

From our perspective, the issue isn't so much the renewable energy not being cheap. The question is how you store it. So, we see negative prices in Germany. We see negative prices in California—we see them quite a lot, when there's a lot of renewable energy available. And in talking with folks--planners at large utilities, and oil companies--they see more of that. The debate is increasingly around, how do you store this cheap renewable energy? And we see a few different contestants out there. One, obviously, is electro chemical storage which we're very interested in. Right now, though, for the most part, with the obvious exception of frequency regulation, energy storage right now--electro chemical storage--is out of the money, although something like 10 to 15 percent annual reductions are available, at least for the next five years. But we don't see long duration energy storage being a really viable option, and certainly not compared to natural gas as a way to store energy in the near term, the next five to 10 years.

Another option for energy storage is natural gas, to provide some firming, et cetera, for this cheap renewable energy for periods when the wind's not blowing and the sun's not shining. The issue, as I understand it, is that as you get closer and closer to Paris levels of carbon emissions, you really have to get off of natural gas. So we're not sure that natural gas without some sort of sequestration solution is the answer. Another possibility is hydrogen. Hydrogen gets a lot more discussion in Europe than it does here, which is, I think, rather surprising. Obviously, there's not a good line of sight right now as to how to get those costs down. The other approach, which I personally am most fond of, is some notion that there's a demand side solution that really gets you there, where there's increased price sensitivity, either by robots or humans, that basically allows us to reduce demand and improves our price responsiveness, so that we don't need that much storage, and we don't need these really massive scale either sequestration or hydrogen solutions. I think that's the question.

So then, lastly, if we do need a revolution (and my answer would be, yes, we kind of still do need a revolution around storage, and not renewable energy per se), where's the money going to come from for the solution? With our clean tech group business, we have a lot of proprietary data around private investments and clean tech. So we track, every year, how much is going into clean tech and we find that even though clean tech is very much out of fashion, as it probably should be, with investors, there's more money going into it than there was a couple of years back. However, the nature of the clean tech investment has changed quite a lot. Some of it includes things that are rather a stretch in that position of clean tech. What we see is that more of the clean tech investment is going into things like shared rides and advanced transportation and technologies, as well as agriculture and food, and in general investments which are more internet of things and robotics oriented, which are more technology and software oriented, as opposed to more fundamental kind of research on energy and efficiency, which tend to involve (as many of the venture capitalists found out to their chagrin) much longer lead times and very long lead times in decision making by utilities and other bodies.

So, yes, there's more clean tech money flowing in. There's also more money flowing in at the project level, as opposed to the technology level, but it's not probably going into areas where we would want it to go if we're trying to solve this bigger question about energy storage or improved energy efficiency. Similarly, we find, in the case of energy storage specifically, that more and more of the monies flowing into later staged technologies tends to be from corporate investors, and it tends to be basically lower risk kinds of investments. So it's not the kind of fundamental, groundbreaking kind of investment that we require to really move storage forward. So, is there a role for government in trying to bring that research to the fore? I would think, yes.

And then, lastly, what about costs? I think, rather simplistically, that old fashioned comparisons of the cost of coal versus solar versus whatever is no longer such a relevant issue. A lot of the discussion now around DER is getting very, very sophisticated, and in some cases, I would argue, maybe too sophisticated in the way that we define the cost of distributed energy resources in a very location and time in a specific way. Something like LCOE is interesting for making international comparisons and longitudinal comparisons, but nowhere near adequate for these kinds of decisions about DER. Furthermore, what I've experienced over the last 10 or 15 years being in this industry is what's really driven things relative to renewables hasn't been cost minimization logic, it's been public policy, and some of that public policy has been driven by considerations around learning and scale effects. So we should make decisions now with an expectation of costs falling in the future. And also, the reality is we have not been able to use microeconomic concepts in the reality of a modern democracy. You just get the stuff done indirectly through subsidizing research and so forth, where there are political constituencies willing to support that, as opposed to a more transparent argument about the relative costs of things. So thank you very much.

Question: I'm just curious whether you can provide a little intuition why the ratios of the cost per ton of abatement for the various renewable technologies are so out of scale with the ratio of the levelized costs? Your charts show utility scale wind having three to four times the abatement cost of utility scale solar, but the levelized cost of wind is actually below…

Speaker 2: It's an artifact of the limitations of the analysis. I think its noise in the data, to be honest. It's a good observation.

Speaker 3.

Thank you, Bill, for the invitation. I'm honored to be here. One of the topics I will discuss today is the EIA wind numbers, which are pretty good right now, so if you're looking for an argument from me with EIA on the current renewable costs, I'm sorry to disappoint. Other points today that I'll run through here in my slides and discussion include the fact that wind costs have fallen quite rapidly. Those declines, in the past, have not been picked up by EIA or others. And I will discuss the broader question, the Bill Gates sort of theory about needing an energy miracle, vs. the idea that we are sort of on track with the carbon reductions we're getting from the clean energy technologies such as wind, solar, LED light bulbs, et cetera. On that question, I agree with Speaker 2 in thinking that we're pretty much on track. I think Bill Gates knew that this session was happening, so this week he posted a blog saying, in contrast to what people may have thought, that it's not an either or situation. He said that we do need both wide scale government R&D and deployment to make this all work, even though he had strongly hinted otherwise in the past. But I do think he still needs to come to HEPG and get a lesson in bid-based, security constrained economic dispatch, because the things he says about the need for baseload and 24/7 power clearly show a lack of understanding of how the grid actually operates and how the portfolio is fitted together through the power pools. So that's for you to take care of Bill.

So when it comes to wind cost reductions, it's largely a question of scale. You look at the wind turbines getting bigger, capturing the higher wind speeds that are higher from the ground, and just having bigger blades with the Pi r-squared effect of the swept area of the blades. You capture a lot more wind with bigger machines. So the costs have come down quite dramatically--over two thirds just in the last six years. Relative to other technologies, wind power is increasingly cost-competitive--and I'm going to be one of many who says that LCOE is a terrible way to look at costs, and yet I have nothing better to use. So I'm going to be as guilty as anybody else for using LCOE comparisons, but you can see wind as very cost competitive with any other technology here. We do tend to use the Lazard numbers. This is Lazard. Other people use Bloomberg, or New Energy Finance. Those are pretty good as well. We've seen a little less usage of EIA numbers in recent years by a lot of utilities and investors. And I think some of the past numbers maybe a reason for that. So it's good to have competition in cost estimates.

One of the key issues is wind versus gas costs. Hopefully, wind costs coming down over the remainder of the decade leads to a point where new wind could be cost competitive with new gas by the end of the decade, and some of this thinking went into the tax credit phase-down that was passed by Congress with the five-year reduction, and so that's our challenge now. Our industry is extremely focused on costs right now, trying to get to the point where there's no tax credit in place, and we can be cost competitive.

Going forward, we do see further cost reductions and further performance increases. Some of the promising opportunities are carbon fiber in the blades, segmented and modular blades, better manufacture and quality control, drone inspection for preventative maintenance, economies of scale in manufacturing (which are certainly responsible for a lot of the cost reductions in both wind and solar, and we expect more of that), and tower innovations--modular and non-steel (such as concrete) designs, which can allow higher towers and capture a higher, and therefore faster, stronger winds. Transmission will allow for utilization of the best wind resources, and the benefit cost studies on the transmission lines that have been done in recent years (for the CREZ SPP and MISO MVP lines) are all coming out around three to one, benefits over costs. So if we exploit just looking at the economics of transmission, and if economic planning became widespread, through FERC policy or whatever, we would access a lot of cheaper wind.

Commodity prices are, have come down for some of the main wind components, and they've not yet been factored into wind technology, so I think we will see some cost reductions going forward based on that. Economies of scale will apply, just in all the various components. In addition, in financing, yield cos, for example, have helped with the financing costs.

So I do think we'll see continued cost reductions, and I sure hope so, because, again, the tax credit isn't lasting forever.

On LCOE and costs, I think it's probably not controversial at this point to say that's a crude number, and a good cost estimate should include the time and place of what you're producing. It should include the 3Rs, as Speaker 1 in this morning's session mentioned--the reactive power, real power, and reserves, and each one is a separate product for which there will be a separate cost and willingness to pay, leading to a price. And LCOE is not very useful for a real evaluation of that.

And then, if you think nationally, public policy wise, in terms of what's important for the country, we've got to reduce carbon reliably and affordably. That's the simple challenge, and it's not that complicated, when you look at where the carbon is produced. The darker states are the states with the big carbon reduction needs, and if we went beyond the Clean Power Plan and implemented Paris, it'd be roughly the same place, because the carbon is where it is. It's in the central states. I'm very optimistic about wind, because look where the wind is. The wind is where the carbon is, and wind is displacing carbon. Very cheap, you know, two cent wind in these areas that have a lot of carbon is going to be a very valuable product.

With respect to EIA assumptions, since that was on the panel description, in the past there has been overstatement of wind costs and in the EIA rebuttal document in response to a number of critiques, there was an admission from EIA that the capital costs they were using were 30 percent above the market and so there have been times when clearly there was a misstatement, and that can be important. The problem is, for the state regulators in the room, when integrated resource planning takes place and they use EIA costs, or, for the transmission planners in the room, if they use EIA numbers, which tends to be the case, then they vastly undervalue the opportunity of utility scale wind, and the amount of wind you can get from transmission, and the value of transmission, therefore. And so that is a problem, and we've seen a lot of perverse results from the use of bad data. But, again, that problem is generally solved if we use the current numbers, and if they keep up, going forward, with some of these cost reductions, we expect we'll be OK.

There are some other improvements that I would suggest for EIA numbers. With respect to the learning rates for wind and solar, I think, there's a big discrepancy there. And in the EIA projections, when you go five years out, wind stops. Which we're fine with. We're used to facing death a year hence. So five years is like an eternity. We have time to figure that out. But I think that's because of aggressive solar cost reductions in the model. Some people call them moderate relative to SunShot, but I think they are still pretty aggressive, and quite aggressive relative to wind. There's only, like, five percent cost reduction by 2035 in the current EIA projections of wind costs. I think we'll beat that. We've probably already beaten that. So I do think there's a misplaced perception maybe that wind is already mature, somehow, and solar has a long way to go in cost reduction. So I don't think that's right. I think that needs to be reviewed. Also, some regions are higher than the market of the Northeast and West, and the analyses are higher than what the market is showing. There's also a five percent per year cap on the renewable energy increase. We're going to see a lot of increases these next couple of years, and that could be binding. I don't think there's a reason for it.

That's more on the modeling going out. Not so much the cost. The capacity values are low, we think, in the model. You know, if you price things right, for capacity value you should use effective load carrying capability. You have wind that's not correlated with other wind regimes. You still get capacity value, whereas the model sort of assumes that it's all the same wind regime, and the capacity value declines.

Also, there's an assumption that spinning reserves go up when renewable energy goes up. That can happen a little bit, but you look at the actual numbers in Europe, Texas, other places. It's de minimus. So I think that should be reviewed.

So that's the end on cost, and then the last point in the panel session which I think is a very interesting broad question that I'm personally very interested in, which is sort of globally our carbon problem, and, you know, Bill Gates and Paris agreements, not just on the targets, but also on the funding of solutions, where a number of investors are coming together and governments are coming together. And I do think Gates, as I said before, has overstated the need for a miracle, relative to the significant progress that we are getting through deployment of technologies that are new, but we know and understand. And so on that point he seems to be thinking in terms of how, if you're developing software and you figure out the code, then you can produce a million as cheaply as you can produce one unit of your Windows software. Manufacturing a massive turbine is just a totally different thing, and the scale economies and manufacturing of thin film PV and wind, and I assume LED light bulbs and the other technologies that really are making an impact now, those economies come from scale and learning by doing and manufacturing operations, and it's not something that necessarily a researcher in a lab at Harvard funded by DOE can solve. So we need both, and 10, 20 years from now, maybe there'll be a new technology that is even better than we're aware of now. So we should absolutely do both and not either/or. And, again, he preempted my comment with a blog this week saying that it should be both, and we need deployment <u>and</u> R&D.

And then, lastly, he criticizes non-baseload technologies (to use an anachronistic term) and says, you know, you need 24/7 power in order to get reliable power. And that's just so false. As everybody here knows, you need 24/7 power at the end of the process. You don't need 24/7 from every supply source input into the grid. The grid is the true 20th century miracle of technology and engineering, and it integrates all of these sources, and some are variable, some are dispatchable. You need a certain amount of flexible resources to make it all work, and you can do the whole think a lot more reliably and efficiently if you have a large regional power pool with a security constrained economic dispatch. If you have this power pool, and it's dispatching frequently--every five minutes or something like that--then you can operate perfectly reliably. That's why Iowa has over 30 percent of its electricity from wind, without any storage. Most people who don't understand the grid just sort of need to know that fact. You can do high penetration of renewables perfectly reliably and affordably, and the reason is in how the grid operates. And so, I just don't know if he quite understands that yet. So we look forward to seeing him here at the next session. I'll stop there.

Speaker 4.
Thank you. I want to talk about part of a study that I'm part of called the "Full Cost of Electricity." We're attempting to kind of explain the full system costs that go into electricity, from power plant to wall socket. And the presentation I'm giving today is not the full cost. It is part of the full cost. But it is not the full cost.

Let me just go ahead and say that four or five more times. Not the full cost. It's part of full cost. Because, as we've said, I'm going to be presenting some work on the Levelized Cost of Electricity (LCOE). We've already beat it down as much as we can with a hammer in the previous presentations, but I'll agree. There are things that are good about it. It's simple. It's easy to understand. It's typically a single number. What's bad is it often gets inward looking, which we've alluded to with carbon. It doesn't give the full story, particularly with markets and things like that. And the ugly is that it can be flat out wrong and misleading. When we say a single number for the entire country, that's really meaningless.

So I'm just going to go ahead and jump to the conclusions. We've actually calculated the levelized cost of electricity of 12 different technologies in every single county in the United States, taking into account CAPEX, OPEX, fuel, interest rates, and capacity factors. For fossil plants, we've calculated external costs for air emissions—Sox, NOx PM10, PM 2.5, carbon, and fugitive methane emissions for natural gas. One thing we do not consider, though, are taxes and subsidies. There are no subsidies in this analysis at all. So there's no PTC. There's no ITC. We tried to give everything as fair shake as we could, looking for the cost, not necessarily the price.

And so this map [of the United States, showing the least-cost energy technology in every county] is kind of where we end up. This is what I'll call my "reference case." What this map is showing, particularly in the middle of the country, as we've seen in some other presentations, is a lot of utility scale wind. You also see a lot of wind in New England and in some of the Great Lakes area. You also see natural gas combined cycle in some parts of the country. There's 3110 counties in the lower 48 states. So about a third of them go for natural gas combined cycle. A little more than that for wind. And then that blue color is nuclear. And then there's some utility and residential PV that make it in there, and a few natural gas combustion turbines.

In terms of how we got to this analysis, like I said, there are a lot of things that go into the cost of electricity. And, again, we're trying to get at cost, not necessarily price. So I'm putting in many things that we don't currently monetize, like air emissions and things like that. Greenhouse gases. But I'm trying to keep out some of the things that like ITC, PTC, things like that.

So here's a really busy slide showing the main cost assumptions that go into this. I've got 12 different technologies. For coal, we actually required all coal to be at least some CCS. So, we looked at different levels of CCS, all way from coal with 30 percent CCS (which gets it under the 1400 pounds per megawatt hour emissions level) to EIA's and NREL's best available commercial technology, coal with 90 percent CCS. We also looked at natural gas combined cycle plants, and at combined cycle with carbon capture, at combustion turbines and at nuclear, wind, solar PV (utility, residential, and concentrated solar power).

For each of these, I have columns for capital costs. Those are average across the U.S. I calculated heat rates, price of fuel, interest rates, and the lifetime of the plant. We also have combustion rates for multiple pollutants (SOx, NOx, PM10, PM 2.5 and C02) in grams per kilowatt hour. So we have all these numbers in there. We also have lifecycle greenhouse impacts, so upstream impacts. That is, what does it cost to build the concrete steel, put that in the ground? The energy embedded in that. The ongoing non-combustion costs—so, maintenance, parts things like that that go into keeping these things going. We have downstream decommissioning takedown costs. Some of these are estimates. Most of this comes from NREL's *Renewable Energy Future* study. And then we have fugitive methane emissions, based on an average one percent leakage rate of the entire natural gas grid from wellhead to city gate in the U.S. For greenhouse gas, the damages also vary depending on when they're emitted. Ongoing emissions are calculated over the lifetime of a plant and tied through net present value back to today, so, depending on how long the plant's going to run, that's a different price of carbon there. Upstream emissions are the carbon emitted to date to build said plant. And then downstream is emissions related to decommissioning. And then down at the very bottom of this table are fugitive methane emissions, given how much more global warming potential methane has versus CO2.

So we rolled all that into one equation to get a levelized cost of electricity, because we wanted to do a whole lot of things with it.

All of that bringing us back to this reference case. This is the same map that I showed, which reflects all of those things have gone into this. We did 12 different calculations in every county, for each type of energy resource, and we found the cheapest one and put it on the map. And this is where we've ended up. There's lots of natural gas combined cycle, wind, and nuclear.

Question: Is this new build?

Speaker 4: This is new build, yes. I should have mentioned that.

Question: So your map says that in West Virginia and Pennsylvania wind is the lowest cost source, and it beats coal.

Speaker 4: When you take into account carbon SOx, NOx, PM10, PM 2.5.

Question: So all this assumes a carbon price?

Speaker 4: Yes. I'm trying to find the cost, including the health cost, associated with emissions. Here's a map that shows just the levelized cost of electricity, without the emissions externalities. If I do not consider externalities, we start to see coal show up. Here there's some coal in West Virginia. The only time coal shows up here is when I do not consider externalities. When we don't consider externalities, we get more fossil plants, mostly kind of at the edge of that wind corridor there, where the prices were really close, you do see some of those, some of those counties flip to coal.

Interestingly enough, you actually get more solar PV in this reference case without externalities. And we see that if we put a high price on CO2 or methane, you actually see less utility solar PV. You see more wind, and less natural gas combined cycle, and more nuclear. And a lot of that comes down to the fact that there's some pretty high up front embedded energy associated with the solar PV--the energy it takes to actually create the solar panel. So the upstream greenhouse gas costs, levelized over the lifetime of the plant, can be rather high, whereas for wind, they're quite a bit lower. So, before it was about 40 grams of CO2 equivalent per kilowatt hour for solar. It's about 12 for wind. If I have a low price on the CO2, or methane, you go kind of the opposite direction than you'd expect. You get more natural gas combined cycle. You get a little less nuclear and you get a bit more wind. But the numbers are not as responsive as I thought they would be. This low cost externalities scenario assigns about 20 bucks for carbon. And then if we get down to the DOE SunShot goal of $1.50/W for residential PV and a dollar for utility scale solar, you see a lot more solar come up. even with the higher embedded greenhouse gases in its build. But there's still roughly a three way split between NGCC, wind and some solar.

Question: Why does residential beat out utility scale in some spots?

Speaker 4: One big thing I did forget to mention that actually is also included in my analysis is 11 different criteria for whether something could be built in a given place. So for places that are very highly mountainous, you're probably not going to be able to build a very large plant, or places that are already have EPA non-attainment zones, it's probably going to be harder to site something that emits something. Water availability is an issue in certain areas. It's going to be more difficult to build a massive thermal plant somewhere where you have water constraints.

And then, to give another scenario, if you look at something like PPA-backed reduced finance costs for utility scale renewables, you see a lot more build, particularly in wind, other than in the Southeast, where the wind resource just isn't that great, and in California.

With respect to PV, I treated that little bit differently, this next analysis is something I thought was really interesting you can do. This is an LCOE map for residential solar PV. This one looks pretty because it's mostly based on solar radiation. And so at $3.50 a watt installed for residential solar, this is kind of what I estimate that the levelized cost of electricity is. If you compare that to average electricity rates in a given location, these are also quite different, all the way up from Washington state rates, which were really cheap around the Grand Coolie Dam, to California, where things are a little more expensive, to up in Michigan. And then, in this next map, whenever the county goes blue, it shows where I estimate that, based on a net metering scenario (and I know there's a ton of imperfections built into this, because it's not the way it works everywhere), as the cost of utility electricity gets to the point where you're close to the levelized cost of electricity from residential PV, that is probably getting close to an area where it would make sense to flip over. Notice it says rate parity, not grid parity. There's a pretty big difference there.

And so my conclusion is that it all depends on where you are. And do we need a miracle? I think perhaps just putting prices where the costs are can get us pretty close in a lot of areas. I'll stop there.

Question: This whole thing is dependent on your input. So is detailed information on the inputs to your model available?

Speaker 4: Yes. This is, this has been submitted for publication. The decision should be coming back soon. It's a 13-page paper with 80 pages of appendices that has all the information about every single one of my assumptions is spelled out.

We've also actually built the maps into a calculator, where you can interactively change the price of CO2 or the price of natural gas or the capital cost of things, and it actually changes, in real time, the maps. Those haven't gone up yet, because we're waiting for the paper to go through first, but you will be able to change some of the inputs and have it spit it back live.

Question: Will it be at Energy Institute? Is that where you'll find it?

Speaker 4: Yes. It will be on the Energy Institute website.

Question: Did you do a reference case without quantifying any of the externalities, just the actual cost per county as we speak today as a reference case, before you start doing all the next layers?

Speaker 4: Yes. So I did one here (and, again, this is for new builds), without carbon.

Question: So you're showing West Virginia as wind over coal today, as we speak, no externalities?

Speaker 4: Yes. That's coal with a 30 percent carbon capture built onto it because of the point standards.

The other thing about West Virginia, you know, is that coal is an expensive new plant to build. I wouldn't build it in West Virginia anyway, even without any of this stuff. I guarantee you that something certainly gas would beat coal in West Virginia.

General discussion.

Question 1: As many people around here know, I've got a bit of an obsession with net metering and rooftop PV. And to just put it simply, because all of the utility scale alternatives that you all described are in the wholesale market and have to sell their energy at the wholesale price, and rooftop solar PV, because of the combination of net metering and bundled retail rates, is effectively, for every kilowatt hour generating, getting a price that's two to four times higher than wholesale, how is that and I didn't see that showing up in any of your analyses or your numbers? My sense, from work I've done, is that that disparity is attracting huge amounts of capital towards solar PV. Maybe that's starting to change, but how is that distorting the outcomes that you all are seeing and reporting? And is this something we ought to be worried about, in terms of getting as much clean energy for reasonable prices as we hope to get?

Respondent 1: Yes, there are, as you know, tremendous subsidies, and if one uses any kind of cost comparison in terms of dollars per ton of carbon reduction, it's clear that utility scale in most applications is cheaper than residential. One of the pages I show that I just kind of ran through was taking away the retail based net metering subsidy and using a wholesale price, and then a variant on that, which is some of the value of solar work that's been done in Austin and Minnesota and so forth, and using that to see what happened from a developer's standpoint looking to build a solar project and whether it would still get built. And we looked at about 500 different tariffs, including both residential tariffs and C&I tariffs. And based on those tariffs in place today, and the current definition of the demand charge, and so on and so forth, that would be economic at an eight or 10 percent internal rate of return to build without receiving the full retail price, just assuming, you offset the full retail price to the extent you self-consume, and then you export it at something like a wholesale price.

Questioner: But you still get the net metering subsidy for the portion that you self-consume? In other words, you still continue to assume that retail rates remain bundled so there's very substantial subsidy still built in there?

Respondent 1: That's right, and we're not assuming a transition to TOU or RTP rates in that or to a higher demand charge. That's exactly right.

Respondent 2: Well, in Austin's value of solar tariff, there's actually two meters on the house, so you actually pay at the full retail rate, but you get compensated at a pre-determined rate (that changes every year). So they're giving you what they calculate is the value of that solar energy, but there's two meters on it. And you can argue about the value of the solar tariff calculation all you want.

Questioner: We can indeed, but thanks. In this case we just carry it the way it is, and it definitely does affect the results, and it comes down to who's going to pay, primarily, for the distribution system. And in some sense people who don't have solar are going to pay larger share of the distribution, and not just the distribution system, but the expanded and more expensive distribution system that's required to manage power flow in two directions.

Respondent 3: You certainly have a point, and I think we need to look at rate design here. I don't know the economic policy justification for paying the retail rate. I mean, I have PV on my house, and when I sell back, I still need those wires in my neighborhood just as much as I ever did. So I don't think I should be getting a discount on them. And on the other hand you could say, "Well, it's a subsidy. It's an incentive, just like other clean energy incentives that exist out there, the economic policy justification being that they're maybe second best for a true carbon price or externality based pricing." But the problem is, I think we're in a new environment now where we have vastly differing incentives for zero carbon energy, and if we had a true carbon price and all the externalities factored in, everybody would get the same payment for the same product. So unless and until we sort of have that clear carbon price and we're just relying on that, I think we do need to look at how the different supply sources are compensated to make sure it's nondiscriminatory.

So two things. One, I don't think it's fair to assume that you get the carbon tax and the other subsidies go away. I think it's as least as likely that you get the carbon tax on top of the existing subsidies. My second point is that it's the utilities who are carrying this net metering fight, and the real losers in this fight are the merchant generators as you move down the line, and wind and utility scale solar. And I think a very interesting thing is that the utilities are taking the political heat for something that in many respects is less their fight than other people's fight. Thank you for letting get on my soapbox too.

Question 2: Thank you. If you take Speaker 3's map of where the potential is for renewables and where the projects are, that map showed the percentages of reduction that would be needed with the Clean Power Plan, and then where the actual projects are. In looking at that map, first of all, you saw some mismatch. You saw a lot more wind going in in New England, up in Maine, where there isn't really any need for a lot of carbon reduction. And then, down in the Southeast, where there was a need for carbon reduction, you saw no wind projects there. And then you take Speaker 4's map of where it makes sense economically, and what the costs are.

I would think you could overlay those two maps and still see some disconnects. Why is that? In the Southeast, and particularly the Southeast coastal countries, where there were no wind projects, what is the reason for that? There's no wind? Or is it policy? And then, turning to the costs in Speaker 4's map, it just was an interesting…if you can figure out how to put those maps and layer them and do some comparisons, you'd still see a disconnect in many cases.

Respondent 1: I think that, generally, there's a pretty good overlap. For example, the central sort of region and Great Lake states, where maybe two thirds of the reductions are needed and there's really good wind resource there. That's not true, necessarily, for every region.

The Southeast is not the wind energy industry's strong point, shall we say. But with taller towers there's quite a bit of opportunity that opens up. And with imports--through transmission, there has been a lot of recent importing of say, Kansas and Oklahoma wind into the Southeast, and there are a lot of people looking at doing more of that. But, you know, gas is going to be tough to beat in the Southeast.

Respondent 2: If you look at the wind capacity factor map, that will show you why there's probably not much build out of wind down there in the Southeast. Wind's much better in the middle of the country. But this map shows where wind plants either are being permitted out to be built or in the process of being built. Most of them in New England, New York, and such.

Questioner: And just a follow up question. What do you see as the future? I mean taller towers says to me offshore wind, which might meet with a lot less objection, versus putting them on mountains.

Respondent 1: No, off shore's not going to show up in a cost model, currently, without state based policies. No, the higher hub height opportunity is not just offshore. There's a lot of land-based opportunity. I mean, generally, for wind projects to be realistic, think of agricultural land--farms, ranches. That's where you're going to get quite a bit. There's going to be some smaller projects in more densely populated areas and some on ridge lines, but those are much harder to site.

Question 3: So I noted in a couple of presentations, comments on learning by doing. Some of the multi factor analyses that I've seen suggest that learning by doing is not such a major factor compared to other factors when you look at cost reductions and technology. I'm wondering to what extent any of the panelists have looked at that multi factor analysis and have thought about you know, what is the best way to think about learning by doing, number one. And number two, I found this a very interesting panel and, but when I tried to put this in a context of climate change and think about it as a global problem, I still see a lot of projections of a lot of fossil fuel fired generation coming in the developing world where it's "new on new" competition, and one might think that there would be more renewables coming in. And I'm curious as to why that doesn't seem to be the case. Or should we be more optimistic about what will happen in the developing world, than current projections suggest?

Respondent 1: I'll start. Thank you for raising that question. That is a key question that Bill Gates is appropriately focused on. What do we do around the globe? We've got a billion people without electricity. We've got very low living standards in many countries, and they need growth, and they need all the basic services electricity provides. They also need to do it in an affordable way, and, hopefully, a low carbon sustainable way. So what are they going to do?

One of the great opportunities, I think, for PV is places that are really far from the grid. Think of Africa. A massive continent. I'm going there this summer to look at this very question. And there are a lot of places that are far flung where you're just not going to be able to fund a grid out to those areas. Which means there will be some places where utilities get wind, as cheap as it is, and you're just not going to be able to deliver it to some places. So PV has an opportunity, and hopefully there is a tolerance for not having 24/7 power. They don't have 24/7 power now, and they can maybe store some for evening use. But I think those are opportunities.

Some of the countries, like Tanzania (I'm going there) have found a lot of gas. So you're going to see some gas, I'm sure, there. Other countries don't want to be importing gas and will look more for renewables. And so I do think, in those cases, if they have the ability to build a grid, and they don't have a massive gas reserve they're sitting on, I do think the utility scale renewables are likely, again, to come out as the optimal long term choice, taking all factors into account. If that is the case, they're going to need to work on the grids, which is why, again, I would like Bill Gates and others to be focusing on the grids, so we can have a robust grid that balances wind against wind, wind against solar, and other resources, that can develop the regional balancing that makes it all work.

Respondent 2: EIA just did an international outlook. It did not take account of COP 21 in particular, but even so, a lot of the countries met a lot of their INDCs, which is kind of interesting, even though we didn't explicitly take account of them. That may tell you something about whether their INDCs represent a stretch over what they already planned to do or not, but that's another story.

But we get to the point where, globally, coal, gas and renewables end up having about equal shares of generation by 2040. When we talk about renewables here in the U.S., I mean in the EIA charts, we include hydro, but there's no hydro growth. When you talk about renewables in the rest of the world, there is a lot of hydro growth, and a lot of wind and solar growth going on as well.

But, again, if you're really talking about sort of the ultimate carbon goals, like 80 percent reductions, the electricity as a whole has to be at zero or negative emissions for the world.

A 10-dollar carbon value adds about a penny to the cost of a kilowatt hour of coal fired generation, and about 10 cents to a gallon of gasoline. So in any kind of economically efficient carbon reduction, the electricity sector is completely transformed before any of these other sectors even start to catch a cold. But, of course, that's not the way we're doing it. I mean, we're doing it, in this country, across all the sectors, because it's a more of a process that works in a more political way, not on the principle of getting the cheapest reductions first.

But if you're going to get an 80 percent reduction in carbon dioxide emission, you need a carbon free electricity sector, or a negative carbon sector, where you're burning biomass and sequestering the carbon that comes out of those plants. And even then you'd have only a fighting chance to deal with the transport sector and some of the other places. So it's a real, real challenge.

Looking ahead, the EIA sees a lot of renewables, but also a lot of fossil fuels still in the world. And the question is how serious people are about these goals, and what they really want to do. You know, we talk about Olympic sports in Washington. And, you know, aspirational pole vaulting is a very big Olympic sport, [LAUGHTER] where people stand at the end of the runway and they say, "I can clear 18 feet," and the next guy says, "I can clear 24 feet." And the next person says, "I can clear 80 feet," but no one ever has to run down the thing with the pole and get over the bar.

Respondent 3: I have one or two quick observations. What we've observed over the last 15 years is that it's been industrial organization and supply/demand balances that have driven the really sharp inflections in price that we've seen in the marketplace. So that, combined with subsidies and predictable excessive entry in solar, and before that in wind, have really driven it. This is a fascinating fundamental question.

In terms of the developing world question, what we're seeing at the project level, with a number of our clients, is a battle between basically putting in fixed costs to get LNG, versus doing wind or solar plus storage. So that's a decision which is being made right which will have ramifications for the next 20, 30 years. And in most places that I've seen (at least in Asia and Oceania), gas seems to be winning

Respondent 4: So, obviously, having no electricity is bad, but, honestly, people want the same electricity that we have. You know, so Respondent 1 was talking about how we can have all these intermittent or non-dispatchable resources and work them into the grid and have reliable service to load. Well, people there want reliable service to load, and this goes back to Respondent 2's thing about the cost of storage. Storage is a really a big issue. And when you look at the world, renewable energy might look very good in these levelized cost terms. But, again, having power that you can switch on and off and having power where the load has to follow the generation are very different value propositions.

Question 4: I have a compound LCOE question, the first part of which is very easy, and the second part of which is philosophical and harder. So, to begin with the easy part, I think, on the LCOE calculation, that all those numbers, even the past report LCOEs, they remain essentially estimates, in the sense that you know, the L stands for "levelized" over some number of years and I wonder whether you've collected enough evidence to actually suggest that the expected lifetimes and O&M costs line up with what people are putting in these calculations in the first place. So that's the easy part.

And then the harder part is that everybody used to LCOE and trashed the LCOE at the same time. A lot of these projections are based on optimization models of some kind or deterministic calculations of cost. I wonder whether that's really the right way to think about that. Someone pointed out avoided cost as an alternative. Avoided cost is sort of an elusive concept. I mean, avoided cost today may be extremely different from avoided cost in five years, depending on how the system evolves, and this is all making predictions under lots of uncertainties. So I'm wondering whether anybody has any good alternatives, where you assume a decarbonized electricity sector and think about well, what might be a robust mix of technologies that might get us there? I mean, just recognizing that in the end we're going probably have a mix, because the real world understands there are uncertainties, and we're going to build a mix of stuff. But how do you evaluate the relative value added any given time? I'm not sure, so I'm questioning whether we revert back to sort of the very imperfect LCOE and just recognize that, "Oh, yeah, we have to do other things to integrate these things at some point."

Respondent 1: I'll start on that part that's supposed to be easy, and I have to admit, I don't know that anybody's looked at current O&M costs, relative to prior LCOE calculations, to see if it's on track. I do know O&M certainly is a big issue with these large machines that are put in the worst weather conditions and beat up by winds and shears and all of that. And one of our favorite factoids about wind now is that, nationally, the largest growing job in the country is wind technicians. So that indicates something about the need for workers, and therefore costs to keep wind turbines running. And then, on the second, broader, question, one process we have is states' integrated resource planning. You know, with Clean Power Plan targets, utilities look at portfolios in that process, they're not going to build just one kind of resources. It's not going to be a decision where they say, "Oh, this is half a penny cheaper than the next one, so we're going to do only that." No. I mean, you get declining capacity value for some of the technologies if you do a lot, and there's risks and unknowns, and you can measure that, to some extent, and that will lead you to a portfolio. There are fuel price risks for the non-renewables that you can factor in, which would tend towards adding renewables instead of doing only gas for example. So not every state has integrated resource planning, but in those that do, that's one opportunity to integrate other factors beyond LCOE, and you can use LCOE as a start, but add the other factors.

Respondent 2: Another part of this full cost electricity study is capacity expansion models. We look 50, 40, 30 years ahead and try to figure out what would be the optimal mix to build, going forward, to meet escalating load, depending on what we think it's going to be. One thing I think is useful about the LCOE part is that you can put the externalities into the capacity expansion models as well, and I think the model can make decisions with any kind of constraints, any kind of costs like that.

Respondent 3: On the wind part, [LAUGHER] be careful. We have seen quite a lot of work in looking at historic trends in O&M, and capacity factors versus projections, and in many cases, with many of the manufacturers there have been negative surprises, and as I'm sure you know, a lot of the question is, was it limitations in terms of modeling of the wind resource and the effect of turbulence and the implication for capacity factor there, and then O&M? Similarly, production has been understated in many cases. So there's actually a lot of work on this, and we're actually seeing one of the ramifications of that, and something I wanted to ask about is the opportunity for retrofitting existing wind farms, particularly as the tax investors exit those contracts. We see quite a lot of interest among investors in taking over some of those portfolios.

Respondent 4: Just quickly on that, if you look at the Department of Energy's wind vision analysis, they did find quite a bit of a market for retrofits in the 2020's. You know, we're coming to the end of the design life for some project, and given the significant performance improvements and capacity factor improvements from the new tech, relative to what's in the ground, there is an opportunity there. Not, I don't think, for five or 10 years, but at that point.

Respondent 1: And then on the philosophical question, it's really a great question. The analyst in me says that actually you can address what you said, and you can get much more complicated about it, or you can be much more kind of Zen about it. So, as I'm sure you know, there are people that do agent based models, which we've done with different representations of the psychology of uncertainty and how that affects decision making. And you can get outcomes. The problem is that it's so unconstrained. You can get just about any outcome you could possibly imagine. And then, more broadly, there's the question of, well, if we have an aspiration towards a certain set of policy outcomes in the future…If you step back and look what's happened over the last 15 years, in terms of the rise of renewable energy and so forth and its role in the sector, I think it is very surprising, from where we were. And on the demand side as well, frankly, in terms of improved efficiency. So it's as if there was some broad social desire towards some sort of outcome, and we kind of somehow, very expensively and noisily, migrated there.

Question 5: So, this is terrific and very helpful. When respect to LCOE, there are a lot of components that go into it. For most of them, I know what to do. The numbers that I find the hardest to deal with are the capital costs that are going to be used for these facilities in the future.

And the question I would like to know the answer to is, when we're talking about a new one going in, how much money do they need to get in order to break even, given an adequate return and so forth? And sometimes the capital costs will be higher or lower in the market because of excess capacity. And there're a couple ways to approach that question, and a lot of the supporting documents in the EIA analysis use what I would characterize as engineering estimates of those costs. So, somebody sits down and says, "You need a widget, and so forth, and it's got so much steel…" and you add it all up and you get a capital cost number out of that. And at the other end of the spectrum, just to make the case, would be what happened in Mexico a couple of months ago, where they had their first auction, and they got the winning bid for new solar panel facilities in Yucatan, and if you back out the cost of that, the cost of panels is zero. So they beat SunShot already down there. [LAUGHTER] So I'm a little suspicious that the cost of panels in the future is not actually zero. So what's going on there is somebody's subsidizing this in a hidden way. This is not subsidies from the Mexican government, but it's from the suppliers' loss leaders, whatever. Or it could be that this is a bubble in the supply of technologies, where the Chinese have over built their capacity and now they're dumping, as we say.

So it's very hard to sort those numbers out, and Lazard calls up people and asks them, "What do you think you'd sell it for?" Well, you're getting a strategic answer to that question. If I could believe the engineering estimates, I'd feel much more comfortable that I do with a lot of these other things which have got all these short term fluctuations or strategic estimates in them. And it's really critical, in terms of deciding prospectively if you're going to hope for a large scale expansion of all these renewable technologies.

Respondent 1: On the LCOE, we capital structure quite explicitly, both the cost of capital and the leverage. So for LCOS, we very intentionally had it with 80 percent in equity, whereas with the LCOE what they see as market practice is 50/50. So there are easy ways to play with that.

On your broader question about, do I use engineering estimates or market behavior? I don't know what to say, except that in the long run, the engineering economics should play out, but I don't know if we ever get to the long run. And what we've actually observed, in both the turbine market and I think in solar, is this strategic behavior, many times, dominates what the engineering and economics says. So I don't know. I guess it depends on what ends you're pursuing in trying to make this decision. But certainly in the market which I'm closest to, which is storage, nobody really is pricing rationally. People are pricing strategically to get market share, in order to get run hours, in order to demonstrate their technology, et cetera. It's not sustainable, but it will be until it stops.

Respondent 2: So we're doing a lot of work with Mexico's energy reform. In Mexico, they have clean energy credits, and I believe they're worth about 50 bucks per megawatt hour, and big firms are required to buy them. And so there was some talk about being unsubsidized, but I think those are actually a subsidy, too.

Respondent 3: The questioner is right. There was an auction that surprised everybody who was involved--wind, solar, others… There was a very surprisingly low bid that won, and I don't know what happened there. I think it's important to benchmark the engineering/economic data with market data. You do have the risk that there can be times and places where there could be other things going on, and bids that don't reflect cost. I mean, in the wind industry, with 75 gigawatts in the country, I think we have a pretty robust and competitive market that's mature enough, such that it's hard for me to believe that there's rampant strategic bidding going on in all the utility RFPs.

So I think there is a lot of useful data in the PPAs, and you can kind of back out the capital price, if you know something about their performance and capacity factors and the general financing approach. And there's a lot of industry practice, and you can benchmark those things. I don't know how we exactly know coal plant or gas plant or nuclear plant costs. Obviously, there's been a lot of debate about what an actual nuclear plant costs, and there's a thin market for that. So anytime you have a thin market, it's hard to do, but when there is more actual development going on, industry surveys can be more robust. So I think a combination of those two generally leads to a result, but you're going to probably see some fluky market results in certain places.

Respondent 4: I sort of agree with both my colleagues. I mean, the stuff that isn't getting built is very hard. The EIA is actually now starting to collect the data from the stuff that is being built. So it will be more than a survey. It will be basically all the utility scale plants, including all the wind plants. The EIA is collecting this data on a regular basis. I think we just released 2013 data. We're releasing 2014, so we're starting to actually collect that data.

LCOE has a lot of problems. Obviously, a lot of people see a lot of issues with it. I certainly do, but PPAs are like much worse. Using PPAs as a proxy for LCOEs is just…A PPA does not represent the levelized cost of energy.

On the wind side, I would say another factor that's very, very, very important is the capital cost. And, by the way, the same problem actually occurs in the oil and gas industry even more. So, right now, oil prices have fallen a lot, and with all this talk, you still have some drilling going on. You know, maybe you already signed a contract for your drilling rigs. The drilling is free, and you already leased the land, and you think you might lose the lease if you don't drill it. So there's, like, short cycle economics. There are mid cycle economics, where you still have to pay for the drilling and the completion, but the lease is already yours. And then there's full cycle economics--what would make me go out and want to sign a new lease? And those are all different. Over time, full cycle economics, which is kind of like your engineering analysis, matters.

On the wind side I would say that the actual capacity factors, in addition to the capital costs, are really critical. And there's a lot of talk about 50 percent capacity factors, I noticed in one of Speaker 4's charts, there's a whole region of the country with a capacity factor of 50 percent. The EIA also collects the actual generation data from all the wind farms, and I realize that some of them are older technology and some of them are newer technology. And I can tell you, there are definitely some that have above 50 percent capacity factors, but there's also a lot being built now that, based on what they're reporting as their generation, are nowhere near that. So in addition to the capital cost, in the case of wind, at least, I think the assumptions you make about the capacity factor are very important, and sometimes you will find these analyses being done using plausible, but not typical, capacity factors.

So I worry about the capital costs, exactly as you do. I think you framed it correctly. I don't think there's any answer to it, really, except that, over time, you would expect the thing to fully pay for itself, thinking in terms of full cycle, long run average cost, as opposed to short run costs.

But on the wind, you've got to think a lot about the capacity factors and what you're really getting. Because, again, you can talk about the cost of the unit, but you are moving from the more optimal sites to the less optimal sites, both in terms of the wind itself, which I'm kind of less worried about, but also in terms of distance from the transmission grid. And then the question is, when you look at the cost, if you move further away from the transmission system, do you associate that intertie cost with the project, or do you socialize that over the system? That is a really important question for us. We would tend to associate the cost of tying it in with the project, not to think of it as something to be spread across all customers. And in that world, going back to oil and gas, it's always sort of like Murray Adelman's battle between depletion and advances in extraction. And I think there is a sense in which there are some factors that are less happy, in terms of some of these technologies. Although generally, in terms of the progress of the physical plant itself, we're usually not going backwards, except in the case of nuclear, which we used to be able to build at a pretty low cost, and now the country is much richer, and presumably has much more capability and much more science, and the cost of these things is just…

Question 6: Interesting maps, Speaker 4. I have a couple of quick questions about them. Just looking at your very first map, it looks like there are about 75 percent more counties where the least cost technology is residential PV, compared with utility scale. So I wonder what the explanation for that is. And the other question is, since your analysis is at a county level, I wonder how to interpret that, given that most dispatch, at least for the central technologies. For example, in New England, it's done on a New England level. Anyway, it's much broader than the counties.

Respondent 1: Honestly, wherever residential PV kind of won out, it was because you couldn't really build anything else there. I assume there was a shack with a roof you could put some PV panels on and call it good. [LAUGHTER] National parks, very mountainous regions, places where you'd have a tendency for landslides, things like that, are places where you don't want to build some very large capital intensive thing. So I've got an exhausted review in the 80 page appendices of the paper going through all of these things. But that was basically the backstop. If I couldn't build anything else there, I assumed you could put residential PV there.

And you are right, these aren't the boundaries of dispatch and things like that. And these maps aren't meant to show, this is what should be built here because it's the cheapest cost. It may be that the cheapest thing to build is in a more expensive location, but you have better access to transmission, or things like that, and this map is not showing that. Transmission is very, very, very difficult to price, depending on where you are. I mean, it's orders of magnitude different, depending on whether you put transmission through New York City versus through West Texas, or something like that, I mean, the cost differences are quite large. And I didn't feel comfortable enough with my estimates for locational transmission on a detailed enough level to include that. So this map doesn't speak to that.

Question 7: We briefly talked about hydro development in the developing world. I'd like to know the panel's opinion about hydro development and U.S. or the North American perspective. Where does that fit in to the renewable picture, what are the challenges, and is there any chance of it coming back on the screen? Because it was absent in the renewables picture.

Respondent 1: So, in fact, hydro in the U.S. probably is going backwards, with dam removals and stuff. There are some large scale sites with potential, but I think it's not going to happen. Potentially, there's some small scale hydro.

Canada's obviously different. I went to college in in the province of Quebec, and there's still a lot of hydro. So I'm sure there's a lot of talk about further imports of hydro power into New England. Clearly Canada has huge amounts of hydro in its electricity mix. So hydro is relevant in North America. I think Canadians are very interested in selling more hydro power into the United States. And that's what I know about that.

I think it's fairly safe to say that there won't be a lot of massive hydro development within the United States. And in the world, I think we will see a lot of it.

Respondent 2: I believe Mark Jacobsen out of Stanford finds hundreds of gigawatts of run-of-river hydro and things like that that are available now. Actually getting that built is definitely a different story.

Questioner: So is it because they're all capital intensive, or environmental issues, or all of the above, in your opinion?

Respondent 2: Yeah, people just don't like dams anymore.

Respondent 3: Every few years, there's enthusiasm for retrofitting some of the smaller dams, particularly when there have been a number of attempts, which you probably know better than me, for making the regulatory process easier, so you don't open up the entire permitting process if you're going to retrofit something. But then nothing comes of it. They get stuck in permitting issues, and most investors don't want to take that kind of risk, because it's so hard to quantify.

Question 8: When you look at the renewable development happening nationwide, in the last five years, I think roughly 40 percent of renewable development has been non-RPS related. And I'd just be curious to know if you have a perspective on what some of the drivers of this non-RPS procurement might be. Is it simply renewables competing on an economic basis? Are there other motives driving that?

And my second question is, most of that development is happening in regions that have organized markets. And the question there is, obviously an organized market can help tremendously with the integration, but do you think an organized market can actually facilitate greater levels of non-RPS development than you would see absent a regional market?

Respondent 1: Sure. Good questions. Certainly, an organized market helps renewable energy development, for all the reasons we've talked about. I mean, the integration costs are minimal if you have a large regional pool. And there's a regional planning process that goes with it, so you can get infrastructure planned and paid for. So the larger and the fewer RTOs we have, the better, from a renewable energy perspective. That has always been clear, and it's certainly playing out in the West with western initiatives towards greater regionalization.

It's also true, as you say, that a lot of the renewable energy development in recent years has been non-RPS driven. Think of Texas. We're way beyond the RPS of Texas. I think having the transparent price, with an active market with entities who can hedge, helps. You can sort of get both synthetic PPAs and actual physical PPAs in that type of market, so you can have merchant and non-merchant projects. And, from the buyer's perspective, a lot of gas price forecasting and a lot of the wind development was probably done before the utilities saw the current trough era low gas prices. So a few years ago, they were looking out at higher gas prices, and wind was a hedge against that. And it's anybody's guess, of course, what gas prices are going to be five, 10 years out. So I think wind-gas competition is the main factor there, and increasingly now PV, as well.

And then when Clean Power Plan targets come into that, then you'll certainly see a lot of states and utilities doing a lot of utility-scale renewables without RPSes, as long as there's some type of carbon regulation or price in effect.

Question 9: A quick comment on the last point and then a question. We're a developer. We do solar, storage, and wind, and we're definitely seeing a lot of interest among municipalities and coops, which generally speaking do not have RPS obligations. The interest level is, I would say, largely more in the medium scale size--like a 2-20 megawatt project size. Maybe a little bit higher in some of the western states. With the exception of Colorado and a couple others they are not under a mandate, but yet they are pursing these projects.

My question goes back to something I raised earlier with your interconnection costs, which increasingly we see as significant, and interconnection itself as a barrier. So, for example, in PJM right now, if you want to interconnect a project in PJM there's a three year waiting period. A three-year queue to interconnect a project. Have you observed that or studied that at all? And in wind, is the same kind of thing occurring? I only work on solar and storage, so I'm just wondering what your experiences with that have been, and we certainly see it as a cost impact, because it delays the project, and you have to pay security deposits on all these things. So I'm just curious if you have any observations on the cost impact.

Respondent 1: Yes, the interconnection costs and delays are certainly a major issue for development. There was a question raised before about how do you factor in interconnection costs into these LCOE numbers, and certainly some of the costs of interconnection are directly assigned to the generator. That is something that would be, for example, factored into a PPA, so, from a utility buyer perspective, that would be the cost that matters to them. So that is an issue.

There are a lot of stories about rising costs. I don't know if interconnection costs are necessarily always rising. It kind of depends on where you are. If there was a big build out of transmission, then cost of the driveway's not that much. And if you can get onto a highway, once you're on, then you're great, but what we're finding is that there was a lot of build out, obviously, in MISO with the MVP/SPP highway, and that has really been a critical factor in the growth of wind, as we've seen in recent years. We are, however, reaching the limits of those projects. We're sort of filling up that capacity very rapidly and in some places have filled it up. And that's why the wind industry and AWEA are turning major emphasis back to transmission. We need to get busy on the next round of build out, whatever that's going to be, whether it's more of the new merchant DC-type lines or if it's more of the regional AC network build out, and hopefully a lot more interregional transmission, which was not addressed, and Order 1000 hasn't helped on that. So those are needs, but certainly the interconnection queues and costs are major issue. It's why AWEA had the petition to FERC to have a rulemaking and technical conference about the queue issues that happened recently. All right, what are the best practices, and let's see if we can't spread those around the country to improve the situation there.

Respondent 2: My analysis didn't really take that into account. Because I was considering technology to technology, I was agnostic about the costs of connecting to transmission. Speaking to the fact that some of these lines are being filled up, I think that's why you see the interconnection queue for solar is so very large right now. And West Texas wind and West Texas solar are complimentary in terms of when they're generating electricity. Their peaks are different, so I think while the transmission may be full for wind, there may be room for solar, because it happens at different times.

Respondent 3: In storage, what we're seeing is the delays and complexity of the queues driving a lot of the developers' interest in behind the meter solutions, including addressing frequency regulation and other RTO markets, but taking it from behind the meter for that very reason.

Question 10: We've had a lot of mentions over the last two days about rate design for renewables. And there weren't any panels on that, but just to let you know, NARUC has a task force that is working on rate design for renewables. I believe they are planning a preliminary report at the July NARUC summer meetings in Nashville, and that will be public.

My second comment was on the maps again. You didn't include transmission. The Department of Energy gave the EISPC, the Eastern Interconnections States Planning Council, over 14 million dollars of funding, and these studies and the maps that came out of that, the EISPC energy zones maps, do include existing transmission and planned transmission and they have all of the layers for the things that Speaker 4 talked about in terms of where there are wetlands and where there are prohibited. NREL (or one of the national labs) is continuing now to keep those maps up to date for the Eastern Interconnection and the EISPC organization, which has now morphed into a revitalized National Council on Electricity Policy through NARUC, and we're bringing in the Western states and the areas outside of the half of the country that was in Eastern Interconnect. I would expect that one of the projects will continue to be the mapping of that area. So that's a resource that's on, on the NARUC website. There are like 40 layers of different things that are there, including where airports are, where military installations are, as well as existing generation.

Question 11: The overall message I'm hearing from you folks is that the economics of alternative forms of energy are damn good and getting better. And I guess the fundamental question I would ask is, to what extent now is the growth of alternative energy baked in, based on economics? In other words, if the government got out of the way, and we just started growing our systems based on economics, would these technologies survive? At what point do you think they would survive without government support? And where are we on that curve, and are we getting close?

Respondent 1: You're getting rid of conventional incentives as well? [LAUGHTER]

Questioner: Sure.

Respondent 1: Just do it on economics, I get the argument. I've heard it a million times.

Questioner: Well, I'm not trying to be combative, I'm just saying those are relevant factors in that…

Respondent 1: You were trying to be combative. [LAUGHTER] Don't tell me you weren't. I was too. [LAUGHTER] We think alike. But there's that factor. There's also, what do you do as a state regulator, whose job it is to keep rates low for their rate payers? What do you do if one set of technologies has zero fuel costs, and therefore you have zero fuel price risk, and the other set has widely varying fuel costs estimates? Right now, the risk, in my view, is not factored into those state commission proceedings very well anywhere. And if that were taken care of, and all incentives were removed, I think wind, at least, could do very well. In other words, let's all compete on 25 year PPAs. And, you know, if you're a gas generator, bid your full 25-year firm power fixed price. I think wind could do very well.

Moderator: I want to thank all of you for sticking with us to the end and thank our panel for a very, very good discussion. [APPLAUSE]