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EIGHTY-SIXTH PLENARY SESSION**

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Rapporteur's Summary*

Session One. Load Serving Entities and Utility Distribution Companies: Expanding or Shrinking Role Going Forward?

Trends regarding the future of end use suppliers (LSEs and UDCs) are diverging widely across the states. Some jurisdictions appear to be reducing their role to perhaps only wires providers, not even operating the systems they own. Non-restructured states do not seem to be deviating in any appreciable way from a vertically integrated model. Even some restructured states seem to be looking to some degree of re-verticalization. What is the appropriate role of a load serving entity or utility distribution company? To what degree, if any, should they be engaged in the generation business? If they do enter the generation space, should it be on a full-scale basis, or simply to assure reliability or perhaps diversity of supply? Or should UDCs focus on facilitating markets, as in New York's "Reforming the Energy Vision?" What role, if any, will LSEs and UDCs play on the customer side of the meter, through programs such as distributed generation, storage, or demand side management/response of one form or another? Do such entities have to play more of a role than mere providers of the wires in order to remain financially viable and to attract and retain motivated personnel? How important is it that LSEs and UDCs be enabled to assure reliability and/or diverse resource options? Is the market itself insufficient to meet those services on a cost effective basis? If LSEs and UDCs play a role in the market beyond merely connecting suppliers and consumers, to what extent should the tariffs for non-wires services be unbundled and the risks be ring fenced so as to protect against socializing risks?

Moderator: Good morning. I'm excited to moderate our first panel topic today, which will explore the wide range of options being considered for providing distribution services to end use customers. That debate spans the spectrum from current vertically integrated

utilities providing more customized services behind the meter, all the way to concepts that have been dubbed "retail competition 2.0," or New York's REV. There are also rebundling discussions taking place in retail competition states. It's a smorgasbord of ideas and concepts.

* HEPG sessions are off the record. The Rapporteur's Summary captures the ideas of the session without identifying the discussants. Participant comments have been edited for clarity and readability.

With us today are four very distinguished panelists that will enlighten on their perspectives on this topic.

Speaker 1.

Speaking from the point of view of a large combined utility, we are seeing that our customers are looking for renewables and energy efficiency, and that the majority of our largest customers have some sort of goal, either for renewable or energy efficiency.

And so our anticipation is that the future will be more distributed. It will be more personalized, and that means that customers will be able to identify very clearly what their goals and objectives are. And that means that somebody's going to be stepping in there to meet those goals and objectives. That's clear to us.

We think that the market drivers for that largely are the customers. In some cases they are looking at environmental drivers. In some cases they're looking at cost drivers. In some cases, it's reliability drivers, or some combination of the three. But those are really what are driving our customers, we think. Some have subsets of those. Some may be looking at all of those.

A viewpoint that we have is that there's a convergence going on among the new technologies that are available--the dramatic reductions in the cost of solar, and the dramatic reductions in the cost of batteries. And that is ultimately converging with our customers' changing desires, and will result, and is resulting today, in changes in our overall industry. The changes are still relatively small for us in our franchise service territory, but we see that that will definitely grow over time. We do have a view that the centralized grid will remain important, but we think it will diminish in importance, and that's probably not where a lot of the growth will occur over time. But it's

really important for utilities like ours to be sure they're taking actions today to position themselves to participate in this new future, where customers are wanting a more personalized solution from some entity that is out there.

So, the question might come, "Well, does that mean vertical integration will go away?" And we don't think that's the case. We just don't see that there's a lot of appetite with the regulators in the Southeast to move away from the current business model, nor the current market structures. As a company, we see a lot of value in vertical integration, and we think that the regulators in the Southeast see a great deal of value in that as well. Our focus is really on our customers and maintaining those high levels of reliability, maintaining the low price, maintaining high levels of customer satisfaction, and enabling those customers then to get the products and services that they really want.

So, does that mean we relax, just because our regulators don't seem to have an appetite? And the answer to that clearly is, no, that's not the case. We see that customers' needs and their desires are changing, and so that means that we've got to be even more innovative as a company to be able to meet those needs and desires. We're looking at distributed energy resources at microgrids, at new ways of interacting with the demand side, at a number of things like that that we're pursuing pretty aggressively at this point. And it's really based on a foundation of growing the culture of innovation. We've got a long history of innovation with our own internal R&D function, but it's also about evolving the business models, not revolutionizing those, but evolving those as needed, and then ultimately delivering those new products and services.

So, some examples are energy innovation centers. We set up a Georgia power marketplace within just a matter of a month or two. And today they've had \$1.3 million in sales. So that was something that got stood up very quickly and has been very successful, really meeting the needs of our customers. Another opportunity we see that is out there is indoor agriculture (and we're not talking about illegal drugs). [LAUGHTER] What we're referring to here is how in urban areas, where there may be abandoned multistory buildings, those could be revamped to house indoor agriculture for either locally grown produce or for pharmaceutical purposes, things of that nature. It's good for us as a company, because it provides electrical load growth, but, more importantly, it's good for the local communities, because it does create jobs in the local communities. It re-utilizes those vacant buildings that are out there, and, ultimately, it provides fresh local produce or pharmaceutical goods.

Another example is Pivotal Home Solutions. This is a subsidiary that we have that serves primarily our residential customers, and basically they provide things like home warranty and leasing services for customers. They've got about 1.2 million customers spread across 17 states. So it's a very robust business. They're able to maintain high levels of margin in that business, and it's a very good way for us to assist those customers.

Another avenue for us is a business called Power Secure, another one of our subsidiaries. Power Secure is more a commercial and industrial business line, primarily, and they have distributed generation. They provide energy efficiency services for customers. They also do some utility infrastructure work, meaning transmission and distribution for other utilities. But, really, the first two items there are their core business. And Power Secure really can

provide solutions all across the spectrum of the grid. So, they can provide some central station storage, central station solar, things of that nature. But, at the same time, their real forte is down at the customer end, and they've got a variety of products and services, many of which are actually integrated together, and that's one of their strengths—for example, integrating storage into customer solutions with things like rooftop solar and energy efficiency. Also, Power Secure has some good experience from a microgrid standpoint, and for customers who want those things, they are well positioned to be able to deliver on those. We've entered into a strategic partnership with Bloom Energy. And we've really leveraged the Power Secure expertise with the Bloom technology, and the intent here is ultimately that Bloom and their fuel cells can benefit from the integration of onsite energy storage, and that's one of Power Secure's strengths, is integrated onsite energy storage. And so this partnership now has resulted in Bloom, for their standard offering, basically including the Power Secure integrated energy storage. What that allows the Bloom fuel cells to do is really do load following for customers much better than the fuel cell as a standalone technology could do. So we see that there's a good platform for delivering value to customers.

We've got an R&D function. We've got the energy innovation center, venture capital fund, our operating utilities, as well as the Power Secure and Pivotal Home Solutions, and the combination of those really is a great platform. We think to meet customers' needs down at their level and allows us to personalize those for the customers.

We have a belief that a customer focused distribution company really enables high value for customers. And one of the primary ways that we believe that occurs is by being able to aggregate the various value streams that those distributed technologies and resources can

create. So there may be values on the distribution system. There may be value at the transmission system. There may be value from generation capacity. As a vertically integrated utility, we're able to see all of those value streams and aggregate those for the benefit of our customers.

Some services might get rate-based if they benefit all of the customers. Others may be unregulated. Gulf Power entered a settlement last week that will allow them to rate-base behind the meter electric vehicle charging stations where it benefits all customers. That's something their Commission will vote on next week. We anticipate that that will get approved. That's an example of being able to deliver those products and services to customers, in that case on the regulated side of the business, and to do it very effectively for them.

But for a utility really to be successful in this space with the changing needs of customers, they've got to be adept at what they're doing. They've got to be nimble, and they've got to be very customer focused. That's very clear to us.

There are some issues, of course. One of those would be affiliate transactions. If you've got some regulated businesses and unregulated businesses, that's always a concern. Our regulators have dealt with that for years. We've had unregulated lighting subsidiaries and unregulated appliance sales and service subsidiaries for decades, and our regulators have successfully been able to deal with that and ensure that there are no cross subsidies there.

We've got to be able to incorporate the changing role of the distribution system in our planning processes, recognizing that flows will be two way, that some customers are going to want differing levels of reliability from other customers. But that's really true regardless of what the business model is and what the market

structure is. That has to be done from a planning standpoint.

And the regulatory frameworks are really important, especially the retail rate designs for electricity. We just don't see the current paradigm with retail electricity rates as being sustainable in the long term. So things will have to be addressed there over time. And that also means you've got to deal with the low-income issues that come with that. As you address those rate designs, you're going to have to find a good way to address the low-income impacts.

So, in summary, we see that there is meaningful disruption occurring in the industry today. Utilities such as ours have to evolve. We've got to be nimble. We've got to be innovative. We think that preventing a customer-focused distribution company for participating in that evolving industry is really not in the best interest of customers. It may be, in some regions, but we think that in our region it's really not. And I look forward to the dialog and discussion.

Speaker 2.

Well, you would think that we had actually planned our talks, because everything Speaker 1 said is absolutely right, except his conclusions are 100% wrong. And so this is really fabulous.

And what we look for as a company is we want to do all the same things that Speaker 1 was talking about. We want to go to commercial customers. We want to go to distribution customers. We want to deploy energy efficiency and demand response. But we think, and our thesis is, that we can do it faster, cheaper, better, and that if we have a competitive structure, we'll be able to leverage and bring additional benefits to ratepayers and keep those costs down. So, really, all we ask is a chance to compete, because where we have competed, where markets are open, I think, for the most part, we

and other companies have been incredibly successful at deploying and innovating. And that should be something that we should have on a national scale.

So why are we doing this? One of the reasons that we feel so passionately about deregulation and competition and the power of a competitive market is that we have an enormous climate change problem that we are facing. And we have to be ruthlessly efficient in using competitive markets to leverage private capital into these markets. And if all we do is rely on shareholder dollars to fight climate change, it'll be too little and it'll be too late. And a part of what I'm going to do today is to try to convince you that that is indeed a true statement.

It is all about the ratepayers, at the end, right? And what we're really talking about is that the utility domination of a sector, especially one as important as the distributed energy sector, is not in anyone's best interest. And, again, I come back to that climate change issue. We have 2030 targets and 2050 targets that are incredibly ambitious. One of my favorite statistics is that the 2050 climate change targets require that the entire United States economy--transportation, building, energy, everything else--emit less than 80% of what the electric sector emits today. Shareholder dollars are absolutely needed to make this challenge work, and if all we're doing is putting the burden on ratepayers, then we simply won't get there, and the low-income issues and some of the others that Speaker 1 talked about are absolutely right there.

I just saw in Greenwire the other day this headline: "Utilities look beyond traditional infrastructure to manage new technologies." They want to rate-base cloud computing. That's a fascinating example of something I think probably should be being done by the private sector, not by utilities with rate base. But it's kind of where we are right at the moment.

When we talk about distributed resources, where do companies see a value chain? There's the range from the single facility up to the bulk system. And a lot of us see our value in really three places there. First, we're an aggregator of individual facilities that we can do at scale. We can go in, very much like what Speaker 1 was talking about, and put in distributed generation. We can put in solar panels. We can put in batteries. And then we can aggregate it and sell it up to the ISO level, or perhaps on behalf of utilities as well in areas where the ISO isn't an option.

One of the really fascinating things about the REV (Reforming the Energy Vision) process in New York, which I know many of you have followed, is there was Track One, which was all about how we're going to do this and who should operate the distribution system, who should operate these grid networks that they're talking about in New York. But to me, the far more interesting track in New York was Track Two. And this was the track that was going to talk about how we incentivize utilities to buy into the REV infrastructure. And, unfortunately, that process has kind of gotten a little bit bogged down. But (and this is something true whether it's an integrated utility or a competitive market), when it comes to the question of what the PUC should be doing to ensure that their utilities are bought in and have a financial incentive to encourage third party distributed resources, they should make it part of their earning cycle. You have to have an interconnection timeline that makes sense. You need to put in firm targets—something like, "You will get a rate demerit if you don't have X percent of DERs being owned by competitive third parties." All that sort of thing. And if we do that, we can actually get everybody on the same page.

This slide here illustrates one of the fundamental reasons why we need to have a competitive market. What the chart here shows is four boxes, organized along the dimensions of low to high innovation, and of level of risk to ratepayers. And, to me, this is one of the really prime examples of why competition and competitive markets will put us in that high innovation, high competition box in the upper left. That's where we really want to be. That's where I think every regulator wants their customers to be. With private capital being deployed. With shareholders, not ratepayers, taking technology and stranded technology risk. Why should ratepayers be taking risk for things that are not part of the natural monopoly? It just makes no sense to me. And we really do see the cross-subsidization issues as extremely problematic. We want to have that shareholder capital at risk. That's what we do as a company.

And one of the things I'll talk about in a minute is why, when the utility is there offering riskless ratepayer dollars, it really undercuts our incentive to deploy capital. It just doesn't work. And if you end up in that situation, you end up at the bottom right-hand box where you have a utility monopoly, low innovation, and a lot of risk on the ratepayers.

There is an excellent paper I really liked by A.J. Gouling. It has one of the great titles of all time, "Railroad Utilities and Free Parking, What the Evolution of Transport Monopolies Tells Us about the Power Network of the Future." And, basically, it says, it's not telecomm that's the analogy to the electric sector today. It's the railroads from the 1800s, where they built these massive infrastructure networks and then have gradually scaled back and continued to be the best darn rail operators they could possibly be, but have stayed out of the rest of the business. And it's an incredibly successful model, and,

frankly, one that I think makes a lot of money for the parties who own them.

One thing you'll hear from us is that we're not anti-utility. We depend on the utility for everything we do. Whether it's for centralized power plants, whether it's our aspirations on the grid to do distributed stuff, the utility is an essential business partner. It's often actually very challenging to come in and talk about your potential customers and tell them, "Hey, you don't need to be growing your rate base, you need to be shrinking it, and you'll make more money doing it." At least, again, that's our thesis. And that can be a very difficult conversation when you're also trying to sell these same utilities on working with you and perhaps co-branding or marketing.

But here's why we see this as an imperative. So, this is a very simple representation of a revenue requirement built out of expenses, taxes, depreciation of equipment, cost of debt and equity. And then, traditionally, as your costs increase and sales decrease, rates must increase. That's a very simple thesis, right? So, as we have more people fleeing the grid, the costs are going to go up as the sales go down. And so what do you do? You simply increase rates. And this is the utility death spiral. As the DERs come in, they put an effective rate cap on what a utility can charge. So, as you have defections and rates naturally go up, as the rate base stays the same, the DERs are basically saying to a customer, "If you're paying than this amount, you should go ahead and flee the grid as well," and, obviously, that's a real problem.

Now, the social programs that Speaker 1 mentioned are incredibly important as we think about long-term utility sustainability, because those social programs are basically a floor. So now we have a relatively low rate cap, as DER technologies come down in price, and we have a

floor that's equal to the cost of all these social programs.

I was shocked when we came across the figure that 14% to 20% of Americans are on some sort of subsidized energy program. That's enormous in terms of the cost shifting and the cross-subsidization, I mean, obviously it's for a good cause, and I don't see any way around it, but it really does put an incredible strain on long-term utility stability.

So what should we not do? The first thing we shouldn't do is make the problem worse. The first rule of holes is, if you're in a hole, stop digging. The answer, in our opinion, is not for the utility to come in and say, "Hey, we're going to rate-base an entire new class of technology that's not part of the natural monopoly, increase the rate base, and make this problem considerably worse." Because they're trying to basically cannibalize their own wires company by investing in these DERs, increasing the total rate base that they have to recover while decreasing the total number of customers and decreasing the possible rate amount that they can charge. So it's somewhat of a vicious cycle, and we think that this is an important part of the discussion. It's not this simple, but it has to be part of the equation to think about these kinds of issues.

So what do we do as the volumetric numbers go down? Well, then there's a natural shift to either a demand charge or a connection charge per month. And one of the things we can talk about is that that's extremely problematic for a person looking to deploy private capital. Because often what we do when we go out and contract with a customer is we have a shared savings agreement. So, for example, "Hey, we saved you \$100,000 a year in charges, we'll take 20% of that or 50% of that," or whatever the number we negotiate is. And as the market shifts, it's very problematic

for existing investment. So, say we build an investment agreement based on today's rate structure. If the rate structure changes, does that make our investment worthless? As regulators and as policy makers, I think we all have to address that question. We want to enhance private deployment of capital. And so some sort of tiered grandfathering system is often what's necessary. That's a real issue for us.

So, for example, we're seeing a lot of proposals for residential fixed charge increases. 44 actions across 25 states and DC. That's a real fundamental shift in how the market's going to work. And long term, it's probably not sustainable. But it certainly makes it very difficult to go and deploy capital today, knowing that the fundamental terms of the agreement are probably likely to shift in the near future. And we have a lot of fun projecting out 20, 30 year deals where we have a battery, for example, that we want to put at a site. And you look at the NPV of that investment, and if you can take a static rate case today, hey, it's a great deal and you should do it. But as we look forward and predict how the rates are going to change and how the demand charges are going to shift, that becomes a much more problematic investment, and it's a real drag on deploying these kinds of green and innovative technologies.

So, I have five really quick principles. The first one's really the key. Utility rate base is precious. It's a precious commodity. It should be husbanded. They should not be going out and investing in these things that the market can provide. They should stick to providing those natural monopoly services and be the best damn wires provider they can be. They should resist the temptation to increase rate base in the short run.

Second, state PUCs or legislatures often have really well-intentioned, green-looking, forward-

looking strategies that then totally kill the market for private investment. For example, we were in the process of putting together a national electric vehicle charging network using shareholder money. And I have to tell you, it failed. It failed for a variety of reasons, and we wrote off a huge amount of capital. But that's competition. That's the way things are supposed to work. So, in the DC metro area, we were actually going out and deploying charging stations. And then shortly thereafter, PEPCO, PG&E, and the other utilities all came in and said, "Yay, that's a great idea. Maryland Public Service Commission, why don't you let us do that, but we'll do it with ratepayer dollars as a pilot program?" Pilot programs just kill me, because there's only 100 charging stations needed in the DC metro area, right? And if you have a pilot program that does 30 of them...or the microgrid pilot's even worse, because there are only a few really good sites for microgrids. And you have a pilot program that comes in with ratepayer dollars, you can't compete against free. Of course, it's not free. Every ratepayer's paying it. Again, my thesis is we can do it more efficiently, so they're probably paying more. But they're taking technology risk and they're putting ratepayer dollars into a space where private capital was already there.

Another example is a Minnesota commercial solar program. Again, a really well-intentioned piece of legislation coming out of the Minnesota legislature, allowing Xcel to come in and directly market...it's a little more than green tariff, because it's actually backed by physical ownership of a facility. And they want to let them come in and do that, and it was great, and all the environmental groups said, "This is good." Well, I think what they don't realize is that now the private capital that's there building out the community solar programs is being driven away, because our customers are now saying, "Hey, we'll just go buy it from Xcel."

And there's nothing inherently wrong with that, but it makes it very difficult to compete, and, again, if you accept my fundamental thesis that we cannot leverage enough investment over the next 20, 30, 40, 50 years from shareholder dollars, we need that private capital. It's extremely destructive to private capital to have that kind of program come in. And it's particularly offensive to me because, of course, we have a state that's trying to do the right thing and a program that's really been successful. I mean the Minnesota community solar garden program has been enormously effective at bringing in private capital. And all of a sudden, we have this program that's coming in and making things difficult.

So, we have been undertaking an extensive modeling effort. It turns out it's very complicated to model the economics of a small battery using actual load data. This data happens to be from Walnut Hospital in California. But the only thing I want you to look at here is the NPV chart. This is for a very small battery installation of a couple hundred thousand dollars. Under existing rate structures, it's NPV positive. Not hugely positive, but it's a small project. But it's NPV positive. That's great. But if we then come in and reallocate the demand charge, move the demand charge down, and increase the amount of fixed cost recovery that the utility charges, such that the utility earnings are relatively flat, the NPV goes negative. This is the kind of investment decision that we struggle with every day. And, again, I come back to the idea that we need a regulatory fix, some means of grandfathering or otherwise protecting sunk investments so that they're not eliminated by future changes. And, listen, a lot of states are already on this. I mean, the net metering panels are sort of the number one poster child for a lot of these principles, but they're actually even more important as we

move past net metering and come into some of these larger programs.

And this is our hypothesis, that retail competition in the Eastern markets in particular is really being hamstrung right now by a price that includes an energy pass-through and a T&D rate that encompasses all the other things that competitive suppliers have to pay. So, let's just take the case of Pennsylvania. The T&D rate is set, obviously, by the rate case. The energy charge, which includes energy and capacity, is simply a pass-through to the retail customer. Where is the billing center cost? Where are the call center costs? Where are the account management, the marketing, the wholesale acquisition and hedging costs coming from? They're all kind of mysteriously in the T&D portion of the retail rate. But the price to compare is simply a pure energy capacity pass-through at cost to the utility. And so one of the reasons we haven't seen the full promise of retail competition in the East fulfilled is because of this dynamic.

If you look at ERCOT as, of course, the example that we all love, ERCOT gets the first-place purple ribbon there. They don't have that problem, and what we see is that they actually have a much lower T&D cost, because it doesn't include all those extra factors.

So we're very interested in exploring this with people, and this is a hypothesis, we haven't proved it out yet. And I'm sure some people will be seeing red, but we should certainly talk about it, and it's certainly something that we're interested in really examining. I have someone working on this right now. It's hard. It's hard to go through a rate case and dig out all the various pieces.

The last thing I'll mention is the federal-state showdown over jurisdiction for DERs. This is

probably only fascinating to the FERC people in the room, but it's really an interesting question, long term, whether a DER selling to the grid is making a sale for resale. And I don't know how we fix that problem, but it's really kind of fascinating. And I'm happy to go over the legalities of that over cocktails.

Speaker 3.

I have been flown here today at great expense by Harvard University to mediate between Speaker 1 and Speaker 2. [LAUGHTER]

And also to reflect with you all for a moment that I'm a historical member of the Harvard Electricity Policy Group. In your packages is one of the historical artifacts of the early work of the Harvard Electricity Policy Group, which is an article that had my name on it from September of 1998. Now, this is an article about the distribution company of the next century, and here we are in the next century.

A couple of observations about context. That article, "Energy Distribution Monopolies: A Vision for the Next Century," was published six months after the initiation of full retail competition in California and about 18 months before the collapse of full retail competition in California in the form of the electricity crisis of 2000 to 2001. The article was informed by early discussions with Hogan and a number of you that led me to a couple of conclusions that have evolved some over the last two decades, and I'll try to acknowledge the evolution and suggest some useful lessons from it.

First, I became convinced early on that there was no natural monopoly over generation, that robust competitive wholesale markets were in everybody's interest. And a big part of the restructuring efforts of the mid-90s were built around trying to create those fully competitive markets and to empower the grids and the grid

operators to make sure that they worked. And we've still got some work to do, and I was proud this week to be part of a coalition to establish more support and more momentum, for example, behind full integration of the Western power grid. But it seems to me that that, for me, is one of the places from which I began, and I didn't really hear Speaker 1 argue that there was some kind of fundamental public policy argument in favor of a natural monopoly over generation. But I did hear him begin to move in the direction of an argument about the scope of natural monopoly in the distribution sector that does go beyond the wires.

And here's where I think I'm more aligned with Speaker 1. NRDC has believed for many years, and Hogan and I have gone back and forth on this, that there is a natural monopoly, not just over the wires, but over a function we called "resource portfolio management." That is, the assembly of a diverse and robust portfolio of generation and energy efficiency services that would collectively create the best solution for customers, in the public interest, in the form of the lowest cost services and the most reliable services.

I am a service fanatic and the place where I differ with both Speaker 1 and Speaker 2 has to do with vocabulary. I counted, and Speaker 2 used the word "ratepayer" in his presentation 35 times. I want you to reflect on that word for a minute. I have dedicated my entire career, totally unsuccessfully, to expunging that word from the American vocabulary. Speaker 2 appears to think that the typical American is absolutely obsessed with commodity cost of electricity. Now, look, the average residential electric bill is just over 100 bucks a month. That's just over three bucks a day. With all due respect, the notion that the commodity price is a critical calculation to someone getting that kind of

service for that kind of bill ("bill," not "rate"), is a proposition I push back on gently.

I push back even more strongly on the proposition that we want to think about distribution companies as providing commodity service to customers. I think they're about much more than that. And part of what they're about much more of is the environmental performance of the sector. Speaker 2 started out with climate change and all that we need to do across the full spectrum of environmental performance. One of the things I feel pretty good about, not complacent, but pretty good about, and one of the things I want to commend all of you for, collectively, is the environmental record of the distribution companies after Sonstelie and I wrote that article in 1998.

So, what's happened since? Since 2000, the rate of growth in electricity use has been less than half the rate of population growth, completely changing a trend that had been strongly entrenched since World War II, where, in fact, electricity use was growing at more than double the rate of population growth. So, there's been a fundamental shift in the patterns of demand growth, and a fundamental shift in environmental performance. As Tempchin loves to brag, and I'm happy to join him, the electric sector has cut its carbon emissions more than 20% since 2005. It is more than two-thirds of the way toward reaching full compliance with the Clean Power Plan of the EPA, a full 13 years before the deadline. That is something quietly to celebrate together. We did not necessarily anticipate it at the early meetings of the Harvard Electricity Policy Group. But it's no argument for complacency, because Speaker 2 is absolutely right, we're going to have to do a lot better than that if we're, in fact, going to be able to achieve the very appropriately ambitious environmental objectives in this sector.

So what does that imply in terms of the role of the distribution companies going forward, seen from the perspective, not of 1998, when Sonstelie and I were first writing about 2017? And let me just give you a quick preview of what NRDC is trying to do there. My colleague, Miles Farmer, is working on this with me and is our most important voice in the New York proceedings, and he'll be an important part of this conversation, going forward, as well. I'm delighted that he's here. As we look at it, essentially in 2014, the Edison Electric Institute and NRDC put out a joint statement which has been made part of the archives and records of the Harvard Electricity Policy Group. It essentially made two arguments, and it really was an attempt to bridge between Speaker 1 and Speaker 2. It said, first of all, look, the electric distribution companies should be seen as critical partners with entrepreneurs, with competitive businesses, in the continuing evolution of the United States toward a clean energy economy, toward a decarbonized economy. This is a partnership. This is not a rivalry. This is not a fundamental zero-sum proposition.

We also argued in that in thinking about how that would evolve, it was critical to avoid the notion that somehow distributed resources, distributed technology, and energy efficiency innovation were grid disrupters, were drivers of an imminent death spiral across the utility sector. The death spiral myth has been out there for as long as time. Sonstelie and I devoted an entire page and a half to it, and as you look back at it, you will see an argument that sounds refreshingly like the current one, except that then the principal driver of the disrupter myth was the Toshiba or Mitsubishi natural gas engine that would fit into your basement and take you off the grid effortlessly and at lower cost. Now, it's a different story, but the fundamental argument that I would make to all of you is that people aren't fleeing the grid. They're doing all

sorts of interesting and innovative new things. They are embracing new technology. They're looking with interest at new options, but everyone who is doing that, by and large, is staying on the grid.

This then raised the question, isn't there something unsustainable about a system that lets people increasingly reduce their consumption, either through efficiency or through distributed resources, and put more and more of the costs on the non-participants? The concern was that we were moving toward a system in which, even if everyone stayed on the grid, many of those who stayed on the grid wouldn't be paying their fair share.

And this is where I want to close my opening remarks by putting forward a modest proposal for how to deal with this, so that, first of all, we retain a robust vision of what distribution utilities should be. We recognize the natural monopoly argument, that there's a public interest in having some functions in a regulated entity, goes beyond more than just the wires, but does not reach out to encompass everything. We recognize that, whether you call it a resource portfolio manager, an orchestra conductor, or a distribution system operator, it is helpful to have an integrator. It is helpful to have someone who, as Speaker 1 says, can see all of the value streams and can help make sure that rewards for benefits that reach into all those value streams are fairly apportioned.

But the orchestra conductor doesn't have to own all the instruments. And here is where I'm with Speaker 2. There is room for partnerships that allow for competitive entities to maintain a robust role and not to have utilities appear to be muscling in and suppressing competition.

So, how do we evolve a pricing model for distribution services that fits that? I'm not sure

where Speaker 1 was going, entirely, with his rate design argument, but he could have been heard to say that volumetric pricing doesn't work anymore. We need to move toward a system in which distribution services are paid for essentially based on whether you're connected to the grid or not. So, you think of very high fixed charges, very low volumetric charges. Of course, for someone like me, for a typical consumer advocate, for a typical low income advocate, that doesn't look like a very good system--suppressing rewards for saving energy, and imposing higher costs for lower users.

But is there a way of avoiding that problem while still taking head-on the issue about making sure that distribution services, the cost is fairly allocated? We think there is, and I'll leave you with our three-part proposal. PEPCO was a pioneer in moving in a direction I've urged all of you to go for as long as you've been listening to me, which is, get out of the commodity model by breaking the link between your utility's financial health and its commodity sales. Distribution companies should not be rewarded based on what happens to commodity sales. They're fundamentally service providers, integrators, orchestra conductors, not commodity sellers. They don't have ratepayers. They have bill payers. Don't reward them as if all they had was ratepayers. That's revenue decoupling. That's the first piece of this. Modest true ups in rates, up and down every year to level out unexpected fluctuations in commodity sales. The theory of revenue decoupling is well set out in the article I wrote with Sonstelie 20 years ago. Sonstelie's was one of the first utilities to take it on.

But that's not enough by itself, as I know Speaker 4 will point out, because if all you're doing is adjusting for fluctuations in sales, and commodity sales are going down, you run the

risk that the adjustments become too big to bear for the non-participants. So you have to do something else. You have to have minimum bills. You have to say, basically, that every residential customer who's connected to the system is going to make a minimum contribution to the system as their share of the cost of the grid and the grid's enhancement. But in doing that, the difference between a minimum bill and a high fixed charge is extremely important. The minimum bill disappears once your kilowatt hour use goes above a certain threshold. Once you're above that threshold, you're being charged per kilowatt hour, just like you are now. The rewards for saving energy are the same. The inducement to do distributed generation is the same. The minimum bill creates a much better competitive environment to adopt Speaker 2's framework than a high fixed charge, and I think I could get Speaker 2 more comfortable with it, certainly than he rightly is with the prospect of higher fixed charges.

And then the final thing we would do as part of an effort to get a good pricing model in place is to move to time-varying rates. This is something Hogan has been arguing for since day one. I herewith embrace it in public. Yes, kilowatt hour charges should tell the truth about daily and hourly and seasonal fluctuations in the cost of electricity. It's still volumetric pricing, but it's volumetric pricing that varies appropriately with the cost of service hour by hour.

Revenue decoupling, minimum bills, time varying pricing. Think of that as a formula going forward for a better system of distribution pricing that unleashes distribution companies to do what the natural monopoly functions would call for, that does not induce them to get out into areas where they don't belong, and gives us a hope, going forward, of continuing that clean energy partnership which, again, is not

hypothetical anymore. It is a robust and glorious feature of the record of the electric distribution systems over the last two decades. It is a record that applies to public power as well as to investor-owned utilities, as I need to acknowledge here. And the solutions that I'm urging, I believe, are as applicable and useful in the context of public power as they are for investor-owned utilities. Public power is nonprofit, but its financial health is tied to commodity sales, just like investor-owned utilities. Removing that conflict of interest, and recognizing the critical distinction between ratepayers and bill payers and voting for the bill payer vision, the customer service vision, as opposed to the commodity vision. That's where I hope we'll go. Thank you.

Question: Could you expand a little bit upon the minimum bill. How is that different?

Speaker 3: The way a minimum bill works, if your kilowatt hour consumption is below a threshold, call it \$20 a month, then you pay the minimum bill. You pay 20 bucks. If you're using more than 20 bucks for electricity, you're on a straight volumetric charge just like now. So, the point is, actually, if your consumption drops to a very low level (think of a house with a big PV system or a vacation home) you're going to pay 20 bucks, regardless of your consumption, because you're using almost nothing, but you're still putting cost on the system by staying connected to the grid. But once you go above the threshold, it's full volumetric. The difference between that and the high fixed charge is that the high fixed charge applies to everybody. Everyone has a reduced incentive to conserve or install distributed generation under a high fixed charge. In the case of the minimum bill, that's true only for people using very low amounts of kilowatt hours. And the difference, therefore, is that the minimum bill preserves the volumetric incentive for most

customers. The fixed charge reduces the volumetric incentive for all customers.

Question: And how can we decide on the minimum bill amount?

Speaker 3: Through a spirited regulatory negotiation. [LAUGHTER] But in part driven the actual evidence of what is the value of that distribution service. The house that's connected to the system is getting value, obviously, by being connected. What is a reasonable contribution for that house to make to the cost of enhancing an upkeep of the grid? Tempchin's position is the answer is \$50 a month. My position is \$20. Ashley, you, as the regulator, are going to set it at \$22. Once we're done.

Question: I just wanted to make sure I heard what you said correctly, which is that the utility would be the orchestra leader that determines the value of the services that someone like Speaker 2 would provide to its customers. What is the role of the utility, in your view, vis-à-vis the public service commission, and how would the utility be the one to determine the value of those services?

Speaker 3: So let me be careful. I didn't say quite that, but I could easily have been careless enough to sound like I was. The point that I think Speaker 1 was making, and this is where I am sympathetic, is that he's the guy who is managing the grid. He can see all the different value streams that are coming. He can see locational value, location of resources in different parts of the grid that are stressed. He can see the value associated with reducing the acquisition cost of additional resources. He can see value in reducing stresses on the transmission system. And one of the market barriers to success for the distributed resources is just that, since those value streams are

normally separate, it's hard to get paid for all of them.

What I think the grid operator can see, therefore, is the full value of distributed resources, and it's in the best position to reward that value, but, yes, since it's a monopoly, it needs regulatory oversight in devising those payments. And the way that's historically been done, the model I like, is what I've called the competitive procurement model, where you have a regulated distribution company going out for bids to create a diverse portfolio of resources, for example, or to move distributed generation to a stressed part of the grid. You do competitive procurement. You make sure everyone has a fair shot...and here's where I'm with Speaker 2. I don't think the independent producers ought to be competing against a utility affiliate. So Speaker 1 will be mad at me. But I want Speaker 1 to be in the position of running the competitive procurement, and essentially picking the winners and losers, under regulatory supervision. Speaker 2 won't like that, but the fundamental, that is basically –

Speaker 2: Actually, I do.

Speaker 3: Well, hey, then let me shut up right now. We're there.

Speaker 4.

Good morning, everyone. Before I start my slides, I want to say that I'm very flattered to be invited to come and speak here and a little puzzled. I'm not an economist. I am not an engineer. I don't think about things in the same way that I suspect many people in the room do. However, I do live in Washington, so I want to start by saying that I live in a place where agreement is in short supply. I think you all know that. And I'm happy to say that I agree with a lot, if not all, of what most of the panelists have said.

One of the things that I have spent most of my career on is working in system operations, actually the day-to-day operational electric system, and then I moved in to deploying smart meters and smart grid elements. And so one of the things that I work very hard to do is connect the dots right down to the customer. And so, when I've listened to some of the comments and I've read some of the prep material, I know that we in this room, we like to think about things as a macro environment that people are operating in. We've got these large markets moving in various ways. I think it's useful sometimes to look at it from an individual residential customer's perspective, and that's what I'm going to try to do with my points.

So I want to start by saying I really hope that my grandchildren and my great grandchildren live in a world that's largely fueled by renewable energy. I just ordered my Bolt. I'm hopeful it will arrive any day. So I'm fully vested in the notion of a future that is renewable and clean, and I think that, when we look at it from a utility perspective, and I think that Speaker 1 pointed this out very well, we know that climate change is requiring action. We know that technology innovation is accelerating even more every year, and we know that our customers are not only increasingly digital, but increasingly moving to this notion of a sharing economy, and all of those things have impacts on the way we operate. We, as a utility, really believe in clean energy. We believe in being as efficient as we can (which is why, by the way, cloud-based software should be allowed in rates). And we need to support this decentralized move that our customers are embracing, and we need to find new partnerships.

But we also need to fully understand the effect of this distributed world on the electric system. I already told you I'm not an engineer, so I'm not

really qualified to go into deep detail, but we know that there are impacts on every point of the grid from having distributed points of entry, whether it's changing the local voltages at a residence, or impacting the way voltages behave on transmission, all across the value chain of delivering energy from multiple sources to the consumer. And those are impacts that it is incumbent on the distribution utility, in most cases, or sometimes the transmission utility, to mitigate. That's our obligation. Whether it's installing equipment or changing the way the systems behaves on a minute by minute basis, we've got to manage that.

So we are *de facto* the integrator, whether or not our regulators and other market elements understand that. We are doing that, and we're doing it pretty well. But we're also doing it at a time when we have a relatively small percentage of generation that is distributed. And so, when I think about, for example, Washington, DC, where I just spent two lovely weeks in a rate case, they have an RPS standard that requires 50% renewables by 2032, and a five percent carve-out for solar inside the District borders. So I'm going to sit here, as somebody who is supposed to be thinking about the utility of the future, and I have to imagine, what changes do I have to institute between now and 2032 (which is not that far away) to accommodate 50% renewables, five percent of it inside the borders of a relatively small city that's pretty highly congested from an electrical perspective? Those are big challenges that we have to meet.

We're also doing a lot of work on what I call the grid edge stuff. We have one microgrid project that is more of a traditional campus microgrid that we're working on at Chesapeake College in southern Maryland. What's interesting about this is simply the partnership. When we first talked to the college, they wanted to put in 1.9 megawatts of solar, because two megawatts is

the magic number. You hit two megawatts, then we require you to put controls on and spend more money. So everybody's coming in at 1.9, which is a little annoying to me, because I think it's kind of cheating and avoiding the real problem that we've got. We require controls because we require controls to safely operate the electric system, not because we want to make it more expensive.

But, in any event, we told them that if they put two megawatts on, it would close out the feeder to any other renewable energy until such time as we upgraded the feeder, because we were at capacity on it. And they said, "We don't want to do that. We don't want to close out the neighbors around us from pursuing some sort of renewable energy, what can we do?" And so we worked with them to talk about some advanced controls that we were willing to help design to get onto that. We could minimize those days when there was too much inflow from their site, and that also allowed us to look at putting an edge of network grid optimizer on there to flatten the voltage and make it more normal. And so, by being very transparent with the customer about what problem they were creating for us that were impacting other customers, we were able to come up with some creative and innovative solutions.

One of the things that customers don't understand is what we mean by five kilowatts or seven kilowatts of solar and how their appliances and their home consumes that. They don't understand that, and, frankly, they don't want to understand it, nor do I think they should understand it. But our regulators need to understand, and policy makers need to understand it. And so one of the things that eighth grade science has not taught most of us is that electricity flows at the speed of light. And we don't even understand what that means. And so customers don't understand it when I say, "If

a cloud goes over your house and you don't have a battery and you're not connected to the grid, 100% of the electrical devices in your home will stop, just flat out stop." And they don't understand that. And they also don't understand that the largest appliances that they have this inrush current, such that, even if you have a lot of PV, that still isn't adequate to start your air conditioner. It still isn't adequate, in many cases, to start a compressor. So they don't get that and, honestly, if I could be critical of a lot of the solar providers, they don't explain that, either.

We have an employee who put 19 kilowatts of solar at his home, most of it ground mounted, and then put one-second monitoring on. So, God love him, we've got all this data. So what we can see here is, on a typical day, the number of times during the day his 17 kilowatts were not adequate, so that his house relied on the grid for energy. It's very instructive. And then, we just mapped out the solar irradiance for a month at the Convention Center in Atlantic City, looking at every day, and we said, "Well, how often does the sun not shine at that particular point?" And it's just a point of reference. So in this slide, everything underneath the orange line that's not colored that light blue is when the grid is going to be required to provide energy. And there's literally not a single day for which, during the daylight hours, the grid isn't providing something. And of course we know that the grid is providing certain fundamental values to customers that we don't charge them for, and we don't ever talk about.

Some of this is our own fault. We said, "We're going to provide you energy." We said, "Your appliances use energy," and we stop the conversation there. We didn't say to them, "We're also providing you reliability, we're providing you startup power, we're providing you voltage quality," and we've never had to, until recently, say, "We're also providing you a

platform from which you can transact your energy sales." So we're doing all of that. Customers don't understand any of that.

One of the things that we do is we provide is we provide customers hourly data. And so they can look at their bill, and they can see how many hours are they actually exporting to the grid, how many hours are they importing from the grid, and when do those things occur. And so, they look at this and...oh, no, wait, they don't look at this. I forgot. [LAUGHTER] They don't look at this. Now, there are a couple of people, usually the early adopters, people who are very interested in the way their solar panels are providing, that are going to look at this data, but, largely, they don't. And so here's the problem.

So, this slide shows a bill for my friend, and his name is right there because I'm very proud of him. He is quite a leader in the distribution circles around how to integrate more and more renewables on a feeder at the least cost possible. At this point in time, he was running a credit of \$490. So I would venture to guess that if he weren't Steve, he were, for example, my brother, who's a great guy and a smart guy, but doesn't know anything about energy, he would think, "Man, if I'm getting a \$490 credit, I don't need that grid at all." And he wouldn't appreciate all of these other things that the grid provides.

I just want to spend a moment talking about some of those challenges that I mentioned earlier about being able to make the grid available for the future. We've been spending a lot of time talking about DER and how much of it we can consider to be firm. One of the things that some of our external stakeholders are talking to our regulators about is, if we're putting in new advanced technology like batteries and solar panels and in some places wind, and developing microgrids, we're doing all that, and it will help

offset investments that the regulated utility will have to make. And so it made me think.

I started really thinking hard about how true is that. I mentioned that I worked in system operations for many years, and I don't believe very much in lightning striking only once. Because, in my experience, coincidences and bad things happen exactly at the wrong moment, and we have to pull the rabbit out of a hat and save things from going down. And that's why we design our systems to N minus one or N minus two, and that's why we design all of our systems with as much redundancy as possible in distribution and transmission. Because we have 100% obligation to serve. We have a fundamental obligation to serve 100% of our customers. Now imagine a time when somebody is going to build a microgrid, and they have told the regulators that the local utility will not have to build the additional infrastructure they might otherwise have had to build, and they have this microgrid here to satisfy that need. And so the regulators, who are increasingly under pressure to find ways to prevent rates from going up, they say, "Well, that's a really good idea, we'll let you go ahead and do that." And now, fast forward to 10 years from now, and I don't know why, but that gas fired generator, it blew up, and half of those solar panels were damaged in a hailstorm, like what happened in Austin a while ago. If I don't have capacity on the interconnection point, if I haven't maintained capacity to handle 100% of that load, have I abrogated my fundamental responsibility to serve my customers?

If I no longer have that obligation, then regulators are going to really have to think through how we're going to manage this for all customers in the future. This is not a small issue. It is the fundamental reason monopolies were set up. I'm not arguing that we should stay in the past, but I am arguing that you've got to

remember why we are where we are today, and make sure that you're taking that into consideration. We have a long history of saying that the greater society is served by all customers having access to efficient and affordable energy. That's what our obligation to serve is all about. And you have to keep that in mind as you're moving into the future.

And so, how firm is DER? How much can we consider that to be firm in our planning? Right now, we have some strategies in place. Are those the right ones? Are those the ones that are going to sustain us in the future? I don't know.

The other thing that we've been challenged to think about is all these demand response programs that have historically been targeted at forestalling the need to build generation. That's what they were designed to handle. And some of our regulators have said, "Could you use that program to diminish your need for distribution infrastructure?" And that's an interesting notion. So, certainly, direct load controls, devices that we control and we get to operate something in your home, typically your air conditioner or your hot water heater, they sort of lend themselves to that. But what about dynamic pricing and critical peak rebates, and critical peak pricing? They really provide a great deal of financial incentive to customers, but will customers suffer fatigue? So, on a distribution level, there might be, at any particular location, 10 times over the course of a summer where I'm exceeding the peak capacity of that local feeder or that local set of distribution transformers. And so, are customers going to be willing to actually conserve? How firm can we expect customer behavior to be, over time? So, maybe I'm really not affected by it, because I'm at work all day (and I work for a utility, so I work 18 hours day), so you can operate my air conditioner. I don't need it until 10:00 at night, I'm good. And then I sell my house and I move. And somebody

else, who works from home and really runs their air conditioner a lot, moves in. Well, I don't know, as the utility, that that transaction just happened. But I had built a system that depends on a certain amount of cooperation from the customer.

And so I think that doing some pilots and really thinking through what these long-term implications are would be very useful.

I know I'm running out of time. I want to just say that this platform for the utility of the future, it's pretty much, I think, what Speaker 1 and Speaker 3 have talked about in terms of the utility being the integrator, being in the position to see all these things and understand the interactions and take action is really important.

One of the things that I like to end my discussions with, and this is personal, this is real, is a story about my grandfather. My grandfather did what many people in his generation did. He came to this country. He started a family, and he started a business, and he happened to be a tailor. So he started a tailor shop and he had six kids. He had five daughters. My mother was the youngest of those, but they kept going until they had that sixth, because somebody had to inherit the business, and, God knows, women couldn't do that. But notwithstanding that, I loved my grandfather a great deal.

So my grandfather had his tailor business, and he noticed a trend, and the trend was that there were things called ready-made shirts. That was big news. And so he started incorporating them into his business, and, slowly but surely, ready-made clothes began to be more important in his business. And by the time he died, his tailor shop was, like, 70% ready-made, 30% custom tailoring. And he left his business to my uncle, who I did love, but he wasn't as smart as my

grandfather. And one day somebody said, "There's a new shopping mall opening up," and, by the way, curiously, the shopping mall was Menlo Park in Edison, New Jersey, the first large shopping mall in the country. And my mother said, "You should go move your business there. It's the future." And he said, "No, the rents are too expensive, I don't want to move. I think customers are still going to want to go downtown. I'm staying put."

And we all know how this story ended. My grandfather built a successful business. His son went out of business within two or three years of the decision not to move into a shopping mall. And so I think about him, and I think about the lessons that my own family offers, and I think about our industry. And I think about how it's changing, and how I want to make sure that I'm remembering my grandfather and not my uncle, and that's why his picture is in front of my face every day at work, so that I can keep the memory of that notion of adapting to changing circumstances as a way to survive the future. Thanks.

General discussion.

Question 1: To Speaker 3, you won't be surprised by my question, but I'm really concerned that your advice for the regulatory process in ratemaking dates from 1998, and I'm old enough to remember that. I fear that today that's like putting a Band-Aid on a crack in a dam and expecting it to hold, because it really doesn't solve today's problems.

The idea of decoupling was good when we were just worried about energy efficiency, and the loss of revenues from growth in sales did hurt shareholders, and I think decoupling turned out to be a way to take a bad rate design and make it palatable to utilities, and utilities went home fat, dumb and happy, but it doesn't solve the major

problem we have today, and that is, as customers go from being full requirements customers to partial requirements customers, where they're generating some of their own power, there is going to be a cross-subsidy issue. It's going to affect other customers, and, in the case of solar, my fear is that a lot of those customers that are going to have to pay higher rates, even under decoupling, are going to be low-income customers.

So I don't think that decoupling really solves the problem that we're facing today. And we do care about our customers. We do care about the rates that they're paying, because, in the long run, if our rates aren't sustainable to customers, we're just going to go out of business, ultimately. Taking volumetric rates and making them time of use doesn't solve any problem, either, because they're still volumetric rates. It still means that we lose revenues for every kilowatt hour that we don't sell. And it doesn't necessarily track the costs that we pay, unless there's a demand component within those time of use rates that actually reflects the cost to the system of using power within a particular hour. It doesn't really help anything.

Respondent 1: Why can't it?

Questioner: If what you're talking about is demand rates that are time of use, then maybe we're in agreement on that component, but you said, specifically, volumetric rates that are time of use.

Respondent 1: Right. This is actually an important nuance, and one that I just plead with all of you to help me tease out. Consumer advocates, historically, have been incredibly hostile to demand rates. They have a whole litany of reasons why they don't like them, but they're willing to go with time varying rates that have demand components in the hourly charges.

And, for all of you who've been struggling with this over the years, my quiet plea is, take yes for an answer. They're moving your way.

And I have been listening, also. So, this article said, "Decoupling's the solution." I just got up in front of all of you and said, "It's necessary, but not sufficient. You also need time varying rates with some demand components in the hourly charges, and you need [and I think this is the other crucial part of it] minimum bills, so everybody on the system is making a contribution to the cost of the integrated grid." If I give you all three of those things, you are vastly better off than you were with pure volumetric rates, and you're also better off than just going in and arguing for high fixed charges which you're not going to get. As Speaker 2 pointed out, that that hasn't been working well lately. There is a way forward here. Grab it.

Questioner: To me, "minimum bill" just means negotiating fixed cost.

Respondent 1: OK, and then the question of what the minimum bill should be is an important one. We should spend more time together on the minimum bill concept.

Questioner: OK, that's fair enough.

Question 2: This question is probably mostly for Speaker 2, but I should preface by saying that I am sympathetic to the idea that we have to be very careful about drawing the boundary around what the regulated entity should do and shouldn't do, and there clearly are areas for competition. So, Speaker 2, you were pointing out that you were very worried about the ability to deploy private capital when there is uncertainty about to what extent the pricing or the rates that attract private capital might change over time. To me, that sounds a little odd. You're arguing for competition, but then you're

arguing that competitive activity should be completely isolated from price or regulatory risk. So there has to be some kind of understanding that competition occurs in the space where stuff changes. And I'm particularly worried, because I wonder whether the argument is based on the fact that some amount of the private capital gets attracted based on currently uneconomic incentives. So there has to be some kind of movement away from, let's say, rates that are out completely or significantly out of line with underlying cost structures, creating an opportunity for private investment, which from society's perspective actually doesn't make any sense.

Respondent 1: I largely agree with you, actually. And no private deployer of capital is ever going to say, "We want to be 100% insulated from regulatory risk." But the magnitude of the threat is very large. All it takes is one regulatory action, even a very well-intentioned action, and it completely wipes out the value of your investment. And that's kind of unique, right? Because usually, if we were a more normal kind of industry, we'd just take our marbles and go home. But we can't do that, once we put money into a large piece of equipment. And so I think what regulators have to be is sensitive to those concerns when they make and change new policies.

I actually think the minimum bill discussion is a wonderful one. Because we've spent a lot of time looking at and evaluating that. And one of the things we would just really ask regulators to think about is that the value proposition for a customer installing a piece of distributed energy resource equipment is very different under three scenarios. One is the existing rate. OK, we understand that. The other is a very high fixed rate, which basically eliminates the value of the investment. But the minimum bill approach actually can work for all parties, because it

protects the utility, to a certain degree, from revenue loss, and we've run the numbers on this, and so we've actually supported minimum bills in a lot of places, because that value proposition for us and the customer still works.

And so one of the things that we ask is not that we be insulated from 100% of regulatory risk, but, when the regulators make a decision to transition from one kind of rate structure to another, that they really, really seriously do the numbers. If we go to a minimum bill of \$20 a month, does that still make this investment economic? Is it still sufficient to attract that kind of capital? And, generally, the answer is, in most of the structures we've seen, yes.

So I think it's a matter of degree and education, and just making sure that everybody in the room understands it, and we don't end up in one of these scenarios where we're trying to deploy an electric vehicle charging station and charge for it, and then somebody else comes in and just does it for free.

And I'll give you a perfect example. Princeton University. I drive through Princeton University and drop my wife off every morning, and our headquarters is two blocks away from Princeton University. We wanted to do electric vehicle charging there, and we couldn't, because the head of their microgrid (they have one of the most advanced microgrids), a wonderful guy, Tom Nyquist, said, "Hey, PSE&G says they'll give it to us for free. Why would we ever pay you for it?" And we're like, "Well, yeah." Now, I have to say, it's also been four years, and there are still no electric vehicle charging stations on campus, which makes me a little bit crazy. So I think it's more of a sympathy and understanding of the commercial lifecycle that we're asking for, rather than any kind of guarantee or insulation.

Respondent 2: Can I just add something? Let me just make sure that we understand that the pilot that PEPCO did included having a 50% shared cost to the consumer for charger on their property. So it wasn't public charging. It was private charging, and it was a closed pilot with a finite number of customers. Now, you can argue about whether or not PEPCO should get to recover those dollars, but the fact is that PEPCO needed to then and continue to need to do pilots so that it understands the interaction of customer behavior and the electric system. And, by the way, one of the things PEPCO did that was very innovative, and it was the only utility in the country to do it, was to treat that charger like a demand response device and actually fluctuate the charge on peak moments. The utilities have to learn these things. We have to be able to run tests that enable us to prepare for the future.

Respondent 1: This is the debate we need to have, because, actually, with respect, I don't think PEPCO does need to do that. Using EVs as an electric battery and varying it and selling into the PJM regulation market...we've been doing that for a couple of years.

We've been using it as a demand response product as well. And it's not that you guys can't do it, or that you'd be bad at doing it, but you don't need to do it, because there's a competitive market, again, investing shareholder dollars, that is willing to do exactly the same thing.

OK, and so it wasn't free. It was 50% off, with the rest the other 50% cross subsidized across your ratepayers. And maybe that's the structure we want.

Man: Customers.

Respondent 1: Customers, fine, I like customers, too, but that's the kind of debate that we need to have, and I just say, if it's outside the natural

monopoly, and people like my company are willing to come and invest shareholder dollars, isn't that better for the long-term stability of the grid? And it also avoids putting too much into rate base and exacerbating all the factors we talked about earlier in my slides.

Respondent 2: So, I think that it's very convenient that when you talk about innovation, you can proclaim the utilities are bad at it, but when we want to innovate, you say, "Oh, they shouldn't be allowed to." You got to pick your battle. We are an innovative industry. We've been innovating behind the scenes a lot. We've been innovating less in front of the customer. That's what you're objecting to, that we're innovating in front of the customer. Pick. If you say that I'm bad at it, you should be perfectly willing to let me compete with you. Because you're going to win, because you're so much better at innovating than I am.

Respondent 1: Unfortunately, our failures cost us. My favorite example is actually nuclear development. Speaker 1 probably won't like this one at all, but NRG, actually, right along with Southern Company, had the first license to build a new nuclear reactor in the country back in the mid-2000s. We pulled the plug on that project in 2009 and wrote off \$375 millions of shareholder money. I can tell you, my bonus was affected that year. I remember it very well. But we recognized that that was probably not going to be a great investment, and so we went ahead and pulled the plug. No ratepayer should have to bear the consequences of a bad investment. These electric vehicle charging stations, maybe they'll get used, maybe they won't. But why are ratepayers taking that technology risk?

Respondent 3: There are really two things I want to touch on. One is the minimum bill issue, and the second is the last comment.

On the minimum bill issue, I try to think about what's going to happen over the long term, and I think efficient price signals are really important. And I think restructuring rates is the right thing to do. I think that if you just put in place minimum bills, and we do see very high penetrations of things like rooftop solar over time, volume goes down. And with respect to the revenue requirement, if you assume rate base for the T&D system stays stable over time, then the revenue requirement doesn't go away as that volume goes down. And so you have to continually raise those minimum bill levels over time. And eventually, they're going to approach what a fixed charge would ultimately need to be anyway.

And so it's better to go ahead and give the efficient price signals up front by setting the appropriate fixed charge to cover the fixed costs, the variable charges to cover the variable costs, and that's demand and energy.

The second comment I have is around nuclear. So, we think about, not whether this is good for shareholders in the near term, but, really, about what the best thing for customers is over the next 60 or 70 years. That's the way Southern is looking at nuclear. We see that nuclear will be critical if we're going to meet carbon reduction needs over the long term. We think there's a very clear role for that. We've put provisions in the contract to help protect our customers. And we think that this is the right way to implement the large scale nuclear. We're also looking at other nuclear technologies for down the road, both small modular as well as technologies that we don't anticipate would have some of the same challenges. And so we don't just see this as being the nuclear that gets developed, and then there's no more. We think there's got to be a role for nuclear in the long term if we're going to see the carbon reductions that are ultimately needed.

Respondent 1: It sounds like we're going to have a preview of the next panel. I actually was very sympathetic to someone who said the minimum bill feels like a Band-Aid and that we need something really fundamental. What does a decoupling 2.0 actually look like? And I actually feel like there's been a lack of innovative thought about how to really restructure the rates of the utility of the future, because we all seem to agree that the current course isn't that sustainable. We all agree that things like a minimum bill or high fixed charges don't drive the kind of innovation we're looking for because it doesn't create a friendly marketplace, whether it's a utility or private capital being deployed. So, who out there is actually rethinking and reimagining the revenue model? And it should be the people in this room, but I'm not sure it is, at the moment. Because we spent so much time sort of going over these Band-Aid solutions.

Respondent 4: The third element is time-varying rates. The reason why that is going to be critical is Speaker 4 had those wonderful slides showing you that people who look like they are net zero in terms of their draw on the system are actually drawing on the system all the time. It's just bouncing up and down. As everyone gets digital meters, as everyone's use is transparent, it will be possible to charge on a minute-to-minute basis for what you're actually taking off the grid. Combine that with minimum bills and revenue decoupling, and you have a system that allows a distribution entity to thrive without seeing itself as a commodity provider.

An innovative suggestion on how to structure time varying rates to flag for all of your attention is from the Regulatory Assistance Project. Their proposal, which is on their website, written by a classic consumer advocate who's dug in hard against all forms of fixed charges and demand charges, suddenly puts on the table a time

varying rate with clear demand elements that works with digital meters. Take a look at it. Think about it in conjunction with minimum bills. It helps, Speaker 1, if Speaker 2 says he's willing to look at that, and you know he and everyone like him has dug in against fixed charges, whatever the theoretical arguments, which you and I could have at length, there's a practical argument for taking another look at this, because it's clearly got more appeal among the stakeholders and rate proceedings than higher fixed charges. Look at the combination. None of these is a panacea. None of these is enough by itself, but the combination is interesting.

Respondent 3: I've been enamored with the idea of real time pricing for residential customers for 20 years. I think when we first started thinking about a deregulated market and watching what was going on in California, and then what was going on in PJM market, which is where I'm most familiar, it always seemed to make sense to me, because there are lots of things that I do as an individual and you do because you want to get the best bang for your dollar. But what I have finally concluded, and I still conclude, is that until the technology for consumers to manage the devices in their homes are simple and easy to do...I mean, customers have not got a clue about the elements that go into their bills. Our bills are an abomination. And they've evolved over time, because interveners want to make sure that we're making clear certain surcharges and certain adders and all these things, and if you try to make sense of it now, it's impossible. People who are pretty sophisticated don't understand their bill. They just look at the bottom line. They don't understand that we're decoupled. They don't understand that generation charges are separate from T&D. And now, we think that they're going to be paying attention to hourly pricing, let alone minute pricing, right?

So I think the theory is sound, but you have to have enough technology that doesn't require the customer to understand it. That means all of their appliances have to be replaced. They have to be able to tie to some really intelligent home management device. I think all those things are possible, and I actually am geeky enough that I'm probably going to want to buy them, but they're not there yet. They're not there at a price point that most customers can afford. And I don't think that real time pricing for residential is going to make sense until we get there. Now, real time pricing for large commercials who have those systems, at least in 15 minute increments, probably makes more sense.

Respondent 1: One of my favorite things about the ERCOT market, again coming back to a truly competitive retail market, is that NRG and Reliant and Direct and a number of other retail providers of electricity are advertising based on how good our residential demand response program is. It's kind of amazing. I mean, things that the East Coast would think is like, "Whoa, we can't do residential demand response on a mass level." It's done. We're doing it. And it's not always pretty. Because you're using load shapes that aren't really accurate to any particular customer, but with smart metering, you can say, "Hey, listen, we sent out a conservation signal, you reduced your consumption by X number of kilowatts, we're going to pay you."

Respondent 3: You just described the dynamic pricing program that we have in place everywhere that we have smart meters that can provide that, and we consider it successful. The regulators are concerned, because of the changes in the PJM market, that we can't monetize it the way we used to and they're a little worried about the fluctuation. In fact, they're a lot worried about the fluctuation in those prices. But

demand response is a really smart thing. But if you're leaning on it a lot, how will customers respond? If you're doing it four to eight, maybe 10 times a season, maybe that's OK. But if you're doing it twice a week, customers may not like that. And at the end of the day, we all have to satisfy the needs of these customers.

Respondent 1: Well, I just come back to the first principles again. If it's not a natural monopoly, why shouldn't it be shareholder dollars?

Respondent 3: In Washington, DC, there was a proceeding to talk about demand response and whether or not the utility should do it. And a number of the third-party suppliers said that this should be a competitive thing, the utilities shouldn't do it. And what I said is, "I don't think anything's stopping the third-party suppliers from offering this. The fact is, in that market, none of them did. And none of them do today." And I think that's fine. I think that there is a difference between saying, "Only the regulated utility can do it," and saying, "Everyone but the regulated utility can do it." Those are two extremes. And I would not necessarily be comfortable in either one.

Respondent 1: Just, again, from the perspective of someone who talks to our people going out and developing products and marketing them, the very fact that there was a rate proceeding in DC where the utility asked to get into the business or wanted to be in the business has a chilling effect on our willingness to deploy capital, for all the reasons we talked about. If it's a truly competitive product, where we're the ones competing, hey, we're really interested in that. But if the utility is sort of standing off on the sidelines waiting until we move into the market and then comes in and uses their clout--their name is incredibly valuable. I mean the trademark, PEPCO, right?

Respondent 3: The most hated company in the country. [LAUGHTER] I would be careful going down that line.

Respondent 1: We actually have tested this, and where we have co-branded home warranty services and other things, where we put the utility's name on it and do it with them, we get an orders of magnitude better response rate.

Question 4: A lot of what all of you are talking about is where are we drawing the lines as to what should be within what the utility provides, versus what should be outside of that. And when we look at EV charging stations, I think that will change over time. And when you look at them now, they look like a very traditional service that the utility would provide. You're providing the ability to get electricity and to use it to charge a machine. That sounds pretty traditional.

Now, if we move to significant EV penetration, and everybody's got advanced metering infrastructure, which in a lot of states they don't now, and there's going to be more of a back and forth, well, then it starts to look like something different. I'd love to hear from the panel what you think about these lines around what the utility provides changing for a particular product, let's say a charging station, and also about the concern of if the goal is to increase EV penetration for lots of different reasons, doesn't it make sense to, at least in some jurisdictions, have the utility be very involved, because they can get it online more quickly, and then maybe it transitions to something else?

Respondent 1: First of all, I think EVs are going to change the world. I think that when you think about one single technology that has the greatest opportunity to have the greatest amount of change, I think EVs trump solar panels. But I also think that there is a chicken and egg problem. I would love the ability to install

chargers everywhere and make money on that. I'd love it. But, at the very minimum, I think that the utility can play a role by being the organization that installs chargers to get the market going. Specifically, in some of our jurisdictions, the question is, who's going to install chargers in the places where, today, the people who have the money to buy EVs don't live? There's some concern from some of our regulators about making sure that this infrastructure is extended to lower-income neighborhoods. And so, whether or not there is an opportunity in long term for the regulated utility, I think in lots of places, where competition by the third parties isn't as attractive, the utility can help jumpstart the marketplace. But I'll also point out that VW is making a ton of lemonade out of the lemons that they've been served, and they're going to be doing that in a number of markets, and I'm sure the competitive companies are not happy about that either.

Respondent 2: Let me throw out an olive branch. One of the things that we proposed in California was actually a split responsibility where, if you look at the conduiting that you have to install as the backbone of an EV infrastructure, you have to run a wire. You have to bring it over to a stub in a parking lot. You have to do this, you have to do that, you have to put in special wires lots of different places, and I couldn't begin to tell you what they actually did. We proposed a very clear demarcation where the utility would install, own, and rate base the things that look like distribution associated with the EV charging. And then the competitive market would be the one to market, sell, maintain, and install the actual box. And I thought this made a lot of sense, because it gives a role for both parties and keeps the utility in the place that looks like a natural monopoly. You certainly wouldn't want to have a parking lot where eight different charging companies are all coming in and

installing their own conduit under the parking lot. That makes zero sense. It's economically inefficient. It looks a lot like a natural monopoly. Have the utility come in and do that backbone work, but then leave it to the competitive market, and, win or lose, that investment on the marketing and the sales side and the actual piece of equipment, when that becomes obsolete, we bear those risks, not ratepayers.

Respondent 3: That analysis makes sense to me. There were settlements achieved in California for all three major utilities. They were not unanimous, and they are interestingly different.

For us, right now, we have a practical perspective. We don't want a perpetuation of situations in which Speaker 2 keeps dropping people off in places that should have EV chargers and they don't have chargers. We would like the chargers to go in as quickly as possible. We would like to jumpstart the electrification of the vehicle sector. We agree with Speaker 4 that it is transformative, maybe the most important single element of decarbonization, along with decarbonizing the grid itself, of course.

And this is a place where regulatory proceedings and the kinds of negotiations they can generate may make, I hope will make, a significant contribution. It's been rocky so far. There have been some very intransigent parties, and given the fact that there so many potential winners from getting this moving, I'll just express more than qualified optimism that we will find multiple ways up these hills and we'll get there together.

Respondent 4: With respect to EV charging and the distribution companies' role in that, I don't see it as an either/or. I don't see that it's only the distribution company that ought to be doing

those things or it's only third parties that ought to be doing them, to the exclusion of the distribution company. I think there's a role for both. I think Speaker 4 hit on the role of sort of jumpstarting markets, and I think that's an important role for distribution companies. I made reference to Gulf Power rate-basing some charging behind the meter. That's really to help jumpstart the EV market in their footprint. They're not a very high density population area. They've got a few good size cities, but they don't have a lot of EV penetration today, and they do believe, in fact, that that will help to jumpstart their market.

Over the long term, you get past the jumpstarting of the market. I think there's a role still for the distribution company and third parties to both play a role. And examples that we've got within our footprint where that's been the case over the long term is our unregulated lighting business. They compete with third parties for lighting of parking lots, lighting of ball fields, things of that nature. That's not necessarily a monopoly utility kind of thing, but that unregulated business of the company is still competing over there. It doesn't have to necessarily be regulated distribution. There is a role, though, for regulated distribution, and that's typically street lighting. Think about going up and down the streets for an entire city or municipality. I think that's clearly a good role for a distribution utility. The second piece has to do with how an individual residential customer can hang their own light in their backyard if they choose, or they can get the utility to come set a pole that becomes a regulated piece of infrastructure to provide lighting in the customer's backyard. So I don't see it as an either/or. I think there are roles for both in these situations.

Respondent 2: Is the EV stuff being rate based, or is that a non-regulated subsidiary? That one at

Gulf Power will be rate based if the commission approves it next week, and I expect that they will, but the way it will be rate based is in a manner such that it will not have upward pressure on other customers' rates. And what that means is that for customers who want behind the meter charging, they may have to pay some fee for some of that behind the meter infrastructure, so that other customers aren't bearing the cost of that. There will be additional kilowatt hour sales as a result of higher EV penetrations, and, again, we can see that entire value stream, how that helps to put downward pressure on price where those kilowatt hour sales are in off peak periods, and that's a benefit for all customers. So that's a good way for the distribution company to play in that kind of a world--rate base it, but require revenues over and above the standard rate to make sure that it's not putting any upward pressure on rates.

Respondent 2: This is interesting, because I feel like we have a fundamental lack of communication or lack of understanding of both positions because what was just said. If my business people were here, they would say, "Well, that's the death knell. We would never go into that service territory, because they've already, using rate based funds, put their marker down." And especially something like EV charging. You don't need more than one EV charger per X radius. (I love EVs by the way. I could go on all day about EVs. I have one, I think they're great.) But there's a wonderful study in Japan where they showed that having one charger on one side of the city increased people's willingness to drive by huge amounts. And so, when we hear, "Oh, your private sector can compete with our rate-based investment," or, "We're jumpstarting the market," we hear, "Oh, that market's dead to us."

Respondent 4: That may be true for NRG, I don't know, but I can point to a number or

examples within our franchise service territory where the regulated utility is participating in spaces. They are rate basing things. There are also competitor third parties that are still making investments. So, as an example, solar. The company is rate basing some five, 10, 20 megawatt solar projects at customer sites where those customers have been looking for solar. There are also third parties investing in solar at customer sites. So it doesn't prohibit or prevent third party investment. I see that in our unregulated outdoor lighting business. So it may be true that you might shy away from that, but I know there are a lot of other companies that won't shy away from it.

Respondent 1: I just want to throw out two tangential facts about EVs and distribution systems, just so that you all can think about it. A typical EV charging is equal to half an average house load. And so there is some need for us to be monitoring how many EVs are charging at homes, so that we're not facing, across the country, trillions of dollars in upgrading distribution transformers. It's one of the reasons that our pilot in Maryland was designed to look at how effective using the EV charger in demand response was. It wasn't to monetize it in the market. It was to manage the load at that distribution transformer. It's a really important point. And then the other thing that I want to mention is we envision a future, maybe in the next 10 years where there's a fair number of fast chargers. I'm not sure I completely agree with the Japanese study that was just mentioned. I've seen other studies that would indicate that when you start looking at volumes of EVs, you need to have a lot of charging options available, dispersed correctly. You've got to think about the fact that people aren't going to pull in and charge and come back and move their car, and how's that all going to work? There's some complexity. And the complexity always comes in when you're factoring in human behavior.

And so one of the things that we know is that our ability to support fast chargers may be one of those things that forces us to increase our investment in the distribution side. I mean, that's a pretty hefty draw.

And I do know that studies have indicated that where you have one charger, you should have two, because chargers break, and if customers find out that there's a charger there and it's broken, then they're not going to ever come back to that place. So, if there are two chargers, then they'll keep coming back, and there'll be opportunity for somebody to fix that broken charger. And then, finally, when it comes to the utilities' rate basing of chargers, I just want to add that we are also not in the market of building our own chargers. And so, one of the ways that you can see a point of collaboration is with the charger manufacturers. If we're going to install a charger someplace, we're going to go out with an RFP and competitively bid that work, and it's going to be somebody else's product. We're not going to build our own. There are lots of different vendor points and providers with an opportunity to enter this market in a collaborative way.

Question 5: Thanks to this terrific panel, which has been interesting. I want to try to connect a couple of dots here between Speaker 4's excellent presentation, which I found extremely helpful, and the orchestra metaphor that Speaker 3 talked about. As I recall the comment about the orchestra was, does it need to own the instruments? And the answer is, no, it doesn't. The musicians own the instruments. That's decentralized ownership. That's OK. And the orchestra, of course, sets the salaries and the bonus payments for the musicians, and then they respond to those, whether or not they stay with the orchestra or leave or go someplace else. But at least at the Boston Symphony, it is quite clear that the orchestra does not allow for

decentralized decisions. So, say I would like a little more violin now, personally. That is not allowed. We have a very commanding presence at the center who is saying, “Louder, quieter, more here, get the flutes.” This is decentralized ownership. This is incentives for the long term, but in the operational decisions, this is a highly-centralized decision. This is not decentralized decision.

I think, when people are talking about distributed energy resources, they don’t just mean distributed ownership. They mean decentralized decisions, in the sense that I have a little device in my toaster, I’m not there at home, I’m at the office, but I have a device in my toaster. My toaster’s getting information. I’m programming the toaster. Not the concert master. I am going to decide when the toaster runs, based on the signals that are coming. That’s what I think they mean, and I think that’s the undercurrent. If I’m right, and that’s the thing that we’re talking about, then we have to address all of these things that Speaker 4 has talked about.

And dynamic pricing, I think it’s terrific. I’m all in favor of it. Real time, down to the minute, yes. But pricing of what? Well, it’s pricing of the things that Speaker 4 talked about. So, if you’re going to have this, at a minimum (and there’s this wonderful white paper from New York that went through this story, which as near as I can tell has been widely ignored) you’re going to have to have, of course, real power prices. That’s completely obvious. But you’re also going to have to have reactive power prices and you’re going to have to charge and bill for reactive power. And you’re going to have to have information about the voltage sag that’s taking place. And it’s going to have to be done in a very short horizon, and you’re going to have to have signals about both of those things, and you need them both in some way or other in

order to deal with the voltage problems and the cycling and the surge and all of the other things that are going on.

But I don’t see anybody talking about actually doing that. And the reason, I think, it was widely ignored in New York is because, when people pick up that rock and look underneath it, they are terrified, and they say, “We can’t do this. We [the regulators in the market and all those] we are just so far away from being able to do this.” I’m not personally saying that. I’m all in favor of it. But I do think it’s a reality that if you take Speaker 4’s presentation seriously, and you want to have decentralized decisions, not just decentralized ownership with a command and control at the front that’s running the orchestra, then you have to do a lot more in this pricing area than anybody’s even talking about.

Respondent 1: One of the innovations that we expect to see happening is something that we all call advanced distribution management systems. And I’ve been looking at the offerings on the marketplace, and they are infantile compared to where we’re going to need to be to do the kind of management that you’re talking about, even if you weren’t decentralizing decision-making by customer behavior at that level. Even simply managing DER, EV ,and real time pricing in the wholesale market, just managing all of that, is beyond the capabilities of most of the commercially available technology. And so, it’s something that we’re going to have to evolve.

One of the things that we have been working on is the ability to back cast cloud cover. And so, I’m having a conversation with the person that’s working on this project, and he said that we can look five seconds back and look at the way the clouds are moving and then forecast what impact that’s going to have on load for five seconds in the future. And I was home telling my husband about that, and he said, “Wow, you can do that

every five seconds.” I said no, that’s not a good thing. That is not a good thing. My SCADA system is getting cycle information. We are scanning at two second rates, and we’re getting alerts at cycle times. So, five seconds is an eternity in real-time control. And that’s really pretty much the best that we’ve got right now when it comes to those externalities.

So, we’re going to get there. The technology will get there, but it’s going to take a little bit of time. Now, the good news is, your toaster’s ability to get smart is pretty limited. It’s not going to be there for a couple years, so I think there is time for the evolution of this technology to match what people imagine the markets to be able to do. Markets, in my mind, are virtual. It’s imaginary. Electrons flowing in operating equipment--it’s real and it happens, regardless of what people theorize markets should do. So we’re thinking about markets and dynamic pricing, which I think is great. That does change customer behavior. But it takes time. In the meanwhile, those electrons, they’re instantaneous, or as near to instantaneous as something can be. And so, how do you reconcile those? It’s pretty challenging.

Respondent 2: In an effort to help reconcile them, when you think about distribution pricing, there are two major issues to address, and they’re separate, and they’re interestingly different. One is just the recovery of the costs of the system in an equitable way, which a number of you have been raising, saying that that’s got to be there or this isn’t sustainable. That’s important. The other is sending accurate price signals to guide customer behavior. And both of them, ideally, we would have, and both matter.

On customer behavior, my caution is that with an average electric bill on the order of three to four dollars a day, you don’t have a very potent signal anyway for the typical customer. Don’t

overplay this. Don’t over plan it. Don’t assume that there’s an immense amount that the signal can do by itself to change behavior, although getting the signal more and more accurate is important. I’m not suggesting it’s irrelevant.

I think right now, though, with respect to the issue of recovery of costs and allocation of those costs in an equitable way, it is a significant step forward if we can do what we’ve been talking about here in terms of evolving away from a pure flat volumetric structure and/or increasingly high fixed charges. The useful thing about this discussion is that it has identified some alternatives. And the questioner here is going to keep driving us deeper and deeper, and I’m all for it. Let’s by all means get all of those ancillary services in, because even if you don’t effect behavior at all, the more progress you can make, the more reassurance you’re going to give people around the table about equitable recovery of costs. And right now, if we give our distribution systems that kind of confidence in the future and their ability to thrive in a changing environment, that, I think, is our best hope to a good outcome.

The cautionary tale for me and for all you retail competition advocates in the room and for all the believers in the genius of the marketplace, is that back in the mid-90s, when the California restructuring occurred, to which Sunstelié’s and my article was responding, the one thing that everyone remembers, the awful thing that happened was that all the distribution companies got frozen in the headlights. They couldn’t move. They couldn’t innovate, they couldn’t invest, because they could not see, looking forward, a plausible story about cost recovery and a plausible future for them as anything other than minimalist wires companies. We need to come out of this conversation with a collective confidence that there is a robust future for entities that are much more than minimalist

wires companies. And to the extent we can contribute together to a sense of self confidence within the sector itself, that's an achievement.

Respondent 3: This is one of these places where there's really common ground. The utilities will need to be the concert master, and they will have to have DERMS, distributed energy management systems. It will be very complex. It's something that only they can do, in their monopoly capacity. And so one of the things that we've been urging in the REV process for is to actually allow the utilities to create that platform.

Now, nobody likes this analogy, but they're almost mini-ISOs, and everybody goes "Oh, we don't want that," and I understand. We have to apply a rule of reason here. But there's absolutely no doubt that the utilities will have to invest, and they will have to have a system that uses price signals, but the signal is going to come to aggregators for the most part, or sophisticated individual customers. And they're the ones who will actually be in charge of going out and doing the action that the utility tells them to do.

I hate wholesale analogies, because everybody just squirms in their seat, but you almost need security constrained economic dispatch at the distribution level, right? Because at the end of the day, the utility has to be able to step in and say hey, you, do that or don't do that for reliability and we all need to be in a position to do that. And I don't think that's really a serious question. But so how do we, and this is where I think the REV process is having trouble in New York, how do we actually make that happen? How do we set up those price signals so the people actually respond? And with respect to my utility colleagues, I think they have to decide do they want to be the neutral arbiter, the people who are rate basing the cost of that system and

using those systems to grow, or do they want to be competitors and turn that function over to somebody else? And independent distribution operator. And I think you can have one or you can have the other, but when you try to mix them and have the utility play in both those fields, I don't think it'll work.

Respondent 4: I want to touch on the price signal piece. I think there is a critical role for pricing, and we at Southern have the largest real-time pricing program I'm aware of in the world. We also have critical peak pricing for residential customers, things of that nature, and I think they're very valuable. But pricing, particularly when we get down to the residential level, when we get down to reactive power, ancillary services, things of that nature, I think it can become a little more challenging.

One of the things that I think benefits a vertically-integrated utility is not being able to live in the moment at what are the prices today and expecting customers to respond to those prices today, but to be able to plan for the future and look ahead in time, to ask where the constraints are likely to occur in the future, and then to either cause or incent investment that would prevent those things from occurring. And a prime example of that for us is that we saw in metro Atlanta a need for hundreds of millions of dollars of transmission investment. Instead of making the transmission investments, though, we issued an RFP for generation in metro Atlanta, got generation sited there, and avoided the need for the transmission. We could have had pricing of transmission constraints that would have gone into place, and that would have eventually, perhaps, incited some generators to locate there, but we were able to proactively prevent those constraints on the front end.

I think there is a role for pricing, don't get me wrong, but I also think there's a good role, from

a vertically integrated standpoint, to do long-term planning and to incent in the right way, and it doesn't have to necessarily be through some sort of real-time price or necessarily through some sort of one second or two second price signal.

Respondent 3: This is another place where I think we actually have a lot of agreement. A long-term price signal is actually far more interesting for a deployer of capital than a short-term price signal. Look at the great experiment they're doing in New York. Sounds like you're doing something very similar in Atlanta. Where you have an RFP, to me that is competition at the distribution level. A lot of people, particularly in our industry, say competition has to be marginal cost pricing and it's this instantaneous thing. No, competition can be identifying a need and then putting it for bid to the lowest bidder.

Question 6: I think we're somewhat losing perspective with our customers or ratepayers. We've all seen how consumers are buying products at an ever-increasing rate, or adopting new services at an ever-increasing rate. Uber came around, and within months, suddenly everyone was using rideshare. So I guess the question for the panel is, how do we move the paradigm to where the wires companies and the distribution companies start enabling our consumers to do things--those same consumers who also happen to be the investors in all these new great technologies that we want and need? I think at least two of the panelists have EVs. They probably didn't buy those because of a price signal. And are EVs going to be around in five years? We're now talking technology with carbon neutral ethanol powering fuel cells. So, EVs could be done in five years.

Respondent 1: One of my favorite stories about EVs are about the engineers who said to me,

"From an efficiency perspective, EVs consume more energy in their building than they save you, and they're not really ecologically sound," and da da da. And by the way, they don't make any financial sense. They don't pass cost-benefit analysis. At which point I always say, "Who here owns a Mercedes? Did you do a cost-benefit analysis before you bought it?" Probably not.

Customers buy what customers want to buy, and they have lots of different drivers. Most of them, when it comes to vehicles, are tied up in either a certain level of luxury or efficiency, because those are the two big drivers that people have.

But, to your point, I think that whether or not EVs are the driver of the future the way I think they are, the investment that I made is a five-year investment. That's not a big bet. I'm going to have to spend that money to buy a car, and so I bought an EV. The question is whether or not other people see a value in it, and how customers make their choices. I don't think we're losing sight of our customers. I think we're trying to simplify things for our customers. They walk in a room and they flip a switch and the lights come on, and that's what they expect. And so, when you start thinking about all the variations that we're throwing at them...fundamentally, they flip that switch, that light better come on or they're calling me. Whether they live in a microgrid or they have an EV or they've got solar on their rooftop, they look to their local utility to provide their essential service.

Respondent 2: And the part of the question that I would like to address was the initial part, which said, how do you empower utilities to let their customers make choices? What's the best way to put that utility distribution platform into a mode where it's open to and indeed supportive of

innovation by its customers, and not trying to drive all the outcomes itself?

The best single way I know to do that is to take the distribution utility out of the commodity mode, to remove the whole concept of ratepayers from its consciousness, to remove its inherent interest in boosting commodity sales above and beyond everything else. If you do that, so that it no longer has an interest in whether the customer solution raises or lowers kilowatt hour sales, that is the most powerful single thing I know of. The fact that the effort and the conversation has been around for a long time doesn't make it any less relevant now.

My editorial observation on whether electric vehicles will be around in five years is that, actually, I have been persuaded, having started, like you, without any rooting interest in transportation outcomes and been an informal advisor to Arnold Schwarzenegger who was the most passionate believer in hydrogen fuel cells that ever walked the planet. I think the case for vehicle electrification is now robust enough so that it is not imprudent for us to begin thinking about designing systems to accommodate it. So I think that that debate has moved, but I say that without being so arrogant as to think I know the answer. So I want my distribution platform to have no rooted interest in the outcome, and if you leave them as commodity providers with a paramount interest in increasing commodity sales, they are going to have the strongest interest in electric vehicles you can imagine, and that may not be appropriate.

Respondent 3: I do love EVs. I have one. When I put my order in, gas was at \$4, and I was like, "Oh, this almost makes sense," and then, of course... But that's not why I bought it. I bought it because it's a fun car to drive, and I love it, and I love the technology, and I'm a big nerd.

To me, this goes to, frankly, why the utilities shouldn't be in that space. Because you might be right. Why are ratepayers potentially stuck with stranded costs associated with the move away to a new technology? That makes no sense to me. And, by the way, we talk a lot about EVs, but you could substitute any distributed energy resource, whether it's behind the meter solar, whether it's behind the meter storage, any resource. You just take out "EV" and put in that resource, and all the policy debates are exactly the same. EVs are just sort of a fun stand-in.

But with respect to the other part of your question, what could we do that would enable adoption of these technologies today by utilities, I think you have to look at the competitive market in the East, in particular. In ERCOT, this is really a solved problem. But in the East Coast, the person selling you the commodity electricity would also like to be selling all sorts of other things, including cool distributed energy toys. But we can't market to our own customers in the East, because we don't have supplier consolidated billing. The utility sends the bill, and we get one line. It's often a very cramped line, saying, "Hey, we're supplying you your commodity. Isn't that exciting?" And then the utility, at least PSE&G, who's my utility, sends me 10 little leaflets every month about various things that they would like to do for me and market to me.

So the first thing we can do is take the utility out of that business. Have supplier consolidated billing. There's a petition in Pennsylvania to require this right now. Excuse me, "require" is the wrong word, but allow for it. And if we control the bill as a third-party provider, that also means we could do really cool things like finance. We can finance your distributed energy resource on your bill.

Because everybody's right. Most customers are incredibly apathetic. The last thing on earth they want is two or three or four different bills for their energy supply--one for the supply, one for the wires company, one for their electric vehicle charging station, one for their little magic box in their basement. So if we can consolidate all that onto one bill and have the option, not a requirement, but the option to do that, that would be huge. And along with that, all those other common sense reforms like instant connect. It took me two months and multiple calls to the head of our division to get me moved over to retail supply in New Jersey. And it wasn't anything, but you have to have your account number, you have to do this, you have to wait months. And when I moved three blocks down the road, I had to do exactly the same thing again. These are the kind of barriers to customer involvement and engagement with their electricity that really turns them off. And so many of them are fixable.

Question 7: I'm going to come back to something that was asked earlier about something that was missing from the conversation about pricing. We can't get anywhere, I think, without getting the prices right, but I think there's even a more fundamental question. We're getting into decoupling. We're getting into whether we should have distribution system operators. By the way, I agree with Speaker 3. We should have a DSO that doesn't have a dog in the hunt in terms of the infrastructure to kind of run things. That makes sense. We have ISOs and RTOs, why couldn't we do the same thing at the distribution level?

But I think there's a more fundamental issue, and sometimes I think we've lost the forest for the trees, and that is, how did we even get here to begin with? Why is it that distributed energy resources and DER and REV and the new

proceeding that's going to be launched in Ohio, how did this all happen? Why are we here?

I've got some hypotheses, some questions, but I'd like to get the panel's impression of what they think the biggest reasons are. Are we here because we simply have really bad rate design? Speaker 3, you talked about volumetric charges with a minimum bill, and Speaker 2, you were talking about large fixed charges, basically straight fixed variable pricing that we see in gas pipelines. Is it because we have really bad rate design that we have uneconomic bypass that's been incentivized and that, really, these technologies really wouldn't be in the money if we had the right rate design and the right price signals in place? Is that why we're here?

Or is why we're here the desire for customers purely to reduce their bills? Again, that's a great thing, but are they able to reduce their bills because of uneconomic bypass and then fobbing those costs on others, as Speaker 3 has pointed out as a consumer advocate? Is it truly because of environmental considerations? I could put DER in my house. I can run a diesel generator at my house. Is that environmentally friendly? Or is it because of something else?

Is it because of reliability? All of a sudden, after Hurricane Sandy hit the Northeast, the Princeton microgrid was held out as the paragon of where everybody should go. So, maybe it's for reliability, but how much do we truly value reliability? Is it really for that? Or is it for some of these other things?

And has the technology cost coming down really truly been a driver for this? We've seen adoption long before the technology costs came down. Is that really a driver for this?

And so, before we even go any further, we need to think about how is it that we even got to this

point and answer some of these questions before we move forward, because if we don't understand the history and why we got here, we'll never be able to get to where we want to go.

Respondent 1: My sense is that it's pretty much all of the above. And my recollection is that in the early days of deregulation, the biggest drivers were the energy costs that the really largest manufacturers were faced with and their desire to have competition in the market to drive down that price. But then, I think, other things piled on. I think that the earlier adopters, I think people who have deep concerns about the environment, saw DER as an opportunity to further that agenda, and were willing to pay a premium to get it. And then as those prices started dropping, other customers said, "Gee, I see a payback with federal incentives," (which, by the way, may be drying up in our new world).

And so it's all the above. It's everything happening all at once. And so, while it's useful to maybe trace back in history, it probably doesn't matter so much now, because we are where we are. And by the way, I don't want to minimize the profit agenda that any business person has. They saw an opportunity in a market, and they decided to get in it, "I want to go sell solar systems," or, "I want to sell EV chargers." Because there's a market there, an opportunity to make money. I think that's the great American way. I don't have any objections to that. And so that's a part of the way we got here, too.

Respondent 2: And here's the good news about where we are. The real price of electricity, the electricity commodity price, has been relatively flat for five decades. The electric bill, as a fraction of the economy, has dropped steadily. Carbon dioxide emissions from the generation sector, as I noted, are down more than 20% since

2005. The overall environmental performance of the sector continues to improve. We need to do better. I don't want us to be complacent, but I don't want us to start thinking we're somehow in the slough of despond and mired in disaster.

That myth was out there 20 years ago and was part of what drove, I think, some bad restructuring decisions. Historically, as we thought about rate design, we thought we had two choices, fixed charges or volumetric rates. What we've tried to illumine today is that we've got other choices, and we do not have to view the options as zero sum tradeoffs between those two rate design concepts, where you can't get anywhere, because there are theologians on both sides.

The other thing I hope I was not heard as saying is I was not arguing for the replacement of regulated distribution companies by independent distribution operators. I was arguing that, in fact, regulated distribution companies are capable of taking on that role. And I think the New York REV, in fact, made an important tactical decision early on to give them a chance to step up and do that. And I think that the New York distribution companies responded in a constructive way. I think we should definitely give them a chance to show that they can do it, but I do want to make sure they do not have a rooted interest in outcomes that boost commodity sales, hence my continued argument for the need to break the link between financial health and kilowatt hour sales for the distribution companies.

Respondent 3: I love that question. I think there's sort of the aspirational place where we all think we're going to be, and then there's today. My sense is that when we talk to corporate off takers, and they're kind of the ones that are the most sophisticated about this stuff, they're not signing up with us for some sort of

cool DER technology because it's cheap. That's not to say that there isn't that kind of opportunity out there, but a lot of our corporate off takers are very interested in burnishing their green credentials. They want to be seen as leaders in technology. They want to have cool technologies and cool things, and they're willing to pay a little bit more for that.

Others are very concerned about high reliability products. Hospitals are wonderful. You talked about Princeton University. I was living right next door to Princeton during Sandy, and my power was out for a week and a half, and, literally, across the street was Princeton University, all lit up. It was quite amazing. But the people who value reliability at that level tend to be fairly sophisticated. It's first responders. It's hospitals, it's others who put a high premium on that, and they're willing to pay for that service. So, that's one class of customer, and the corporate off takers interested in doing it for the green cred is another.

The fascinating thing is what happens when it's not just these sort of one-off isolated customers. What happens when these technologies actually really do become cost effective? The cost curve is so steep right now. Take the hospital example that I showed in the talk earlier. I think it was just shy of a megawatt load. And we found that putting in even a really small battery system, even at current battery prices, was economic. It was like a \$250,000 investment for which there was an NPV of \$55,000. That's pretty good. That's really interesting.

So we're finally getting to the point where, if you have the right kind of rate design, and if you have battery costs that are coming down, and if you have someone who values reliability at a slight premium, it can make real sense.

I think we sort of have the current status, where it's still kind of an interesting thing, but not necessarily going to be a major driver of savings. I often feel like we actually make a mistake when we talk about cost as the sole driver of consumer behavior. We talked about the Mercedes and the electric vehicles and everything else. Most of the corporate off takers we talk to have signed wind or solar PPAs, with their NPV negative at this point. And I think almost everybody will tell you that if they signed a long-term contract, it's almost certainly underwater now. And, of course, that's just the push of progress. But they do it for reasons other than 100% cost. It's the interest in the technology. And those are the things that I think are driving us to where we are today, and where we're seeing that demand come from.

Question 8: An observation, as someone who works primarily in New York, is that it sounds like what Southern Company is doing is extremely similar to what's going on in REV, and that there's really a branding issue, which is what is making it seem so different. If you look at REV in terms of what markets are actually up and running and working, it's non-wires alternative markets. It's RFPs, standard offers, etc. And they're looking to move to auctions, but that's not something that Southern Company would be precluded from doing either.

In listening to the debate, sometimes it's framed as being about utility DER ownership, but, really, isn't the fundamental issue a debate around competitive procurement and how that competitive procurement occurs? And then, in looking at the problem, and how is it we can't get these markets working better, and what's preventing more actors from entering a more robust market, I would ask, is the problem actually that we don't have stable markets, we don't have long-term price signals, and that's in large part due to the fact that utilities are having

to do all of this in the rate case context, which is a one to three-year horizon? And so, if they're setting an RFP, it's all happening in a very disorganized fashion? Sometimes there's a pilot. Sometimes there's an RFP. It's hard to figure it all out.

And in the vertically integrated context and in the REV context, would a solution in both cases be to set up separate, consistent rules that apply from rate case to rate case surrounding how we're going to decide on cost recovery, on what the values that are going to be factored into the decision making are going to be, etc., and is that something that everyone can get behind?

Respondent 1: I'll just add to that. I think you're right on target. It's the long-term price signals that are really important in long-term certainty. And so long-term contracts are really important for folks, as is the stability of knowing what kind of rate design is going to be in place. That's why I think it's important to go ahead and move to the long-term efficient price signals, rather than have price signals that are going to migrate over time, as a minimum bill might as penetration goes up. I think that's what will help folks.

Respondent 2: I tend to agree with a lot of that. RFPs aren't a perfect solution, but they certainly are a competitive market that we can participate in. And where they're driven by cost savings and overall reduction in utility rate base, I actually think that makes a lot of sense. Every utility should be doing it.

In New York, they do have the added pieces that they're trying to do, which I think is actually even a little bit more exciting, which is things like the distributed load relief program (DLRP), which is basically a zonal feed-in tariff for demand response or for small behind-the-meter generation or storage of other sorts. That's really

exciting, because that is a long-term capacity price signal that they send. They don't call it capacity, because capacity's a dirty word. But it's basically a capacity payment, plus an energy payment when it's dispatched, and those are stated rates, and they're geographically variable. I think that program is a wonderful collaborative model, where the utility sets it up. They identify where they need the resource. They put forward the value proposition and then allow people to compete for it with the combination of both long and short-term price signals.

Question 9: So, first I want to say, great panel. There's nothing like this topic to get the head spinning, and mine has been spinning over the last hour and a half or so.

A couple of thoughts are percolating in my head. So much of this is customer driven. And while we do have our EV drivers, there's also the market that's kind of the show-me-the-money market that has driven the more aggressive penetration of solar rooftops. And so, while we have both camps out there, and they overlap and interact, clearly, "showing me the money" is important. So we've got that over here about how consumers are responding.

And then, on the other hand, we've got this carbon problem, which is kind of the backdrop and to some extent the reason why we're doing this all. And I typically come at this, not from a distributed world, but from a whole system perspective. My biggest concern in all of this has been whether we're doing the right things, the things that we need to do to get there, whether we're using our carbon bucks efficiently. And some of the things I've seen, some of the things one of the speakers alluded to about rate structures promoting certain technologies over others, I think, has not been helpful.

My question is this. Given that this panel is about distribution companies versus competitive companies and how those markets interact, which one of your models do you think, if I'm someone concerned about getting the price signals right so we're making the right choices about implementing the right technologies that'll allow us to solve these problems, which model should I put my money on, because, from my standpoint, the differences in the cost of deployment of the two things, between a distribution company versus something like NRG, is going to be fairly small, compared to picking the wrong horses and doing things in a much less efficient way than we otherwise could.

Respondent 1: First of all, I don't think distribution companies are going away. And I think that there are some really significant challenges that regulators are going to start to deal with, and, quite frankly, I'm very glad I'm not one of them, because they're hard, they're really hard.

So, when we think about the distribution companies' obligations as they are today, I have to react to customer choices, and I have to react really quickly to those customer choices, even if I'm in between rate cases. If, all of a sudden, 10 people on one distribution transformer buy an electric vehicle, and I don't have a regulatory ability to manage that load, I'm putting in a bigger transformer. If, all of a sudden, every customer wants to put in DER, and relatively large systems, on a feeder that hasn't otherwise been upgraded, I'm going to have to go upgrade that feeder.

The question for the regulators is, do they want me to be simply reacting all the time? Do they want me to be able to predict? So, if that EV market goes away, but I've already had to build capacity to handle that, what are they are going

to do? Take those rates away from me? How are they going to manage through this?

So do I react or do I plan? Do they want everybody to be able to do whatever they want, knowing it forces costs on to the distribution company? Do those costs get socialized across all of the customer base? Or should the cost causers pay for it? If the cost causers pay for it, the last one to buy an EV is going to have a hell of a bill. The last one to put DER on their roof, they're going to be footing a large part of the bill.

These are really tough questions. So, while we've been having this very robust discussion about what the competitive players want to do and what the regulated utilities want to do, what we haven't been talking about is the role of the regulator in figuring that out.

I would agree that the distribution system is the orchestra leader for what's installed at this moment, but the regulations that are put in effect by our local regulators will have an enormous impact on whether we're reacting or staying in front of things and how the market plays out in any jurisdiction.

And what we know is our customers are different. The customers in New York who have smaller properties in smaller space and lower bills because of that are really different than some of the customers that I have that have really big, giant 10,000 square foot homes and lots of stuff. And those people are really different than renters in a condo downtown or an apartment downtown. And I know my customers in Delaware behave differently than ones in DC, and differently than the ones that are in rural areas in southern Maryland and Jersey. Regulators are going to be making a lot of decisions that impact not only how I behave, but how companies like NRG behave.

Respondent 2: That we certainly agree on, but I take fundamental issue with your premise that the regulators are currently allocating our carbon dollars well today.

I've gone an hour and a half without mentioning the nuclear subsidies in New York. \$7.6 billion in New York and two point something billion dollars in Illinois buys a hell of a lot of renewables. And we did not even bother to put it out for bid.

Ratepayers have a limited amount of capital to spend to take on the climate challenge, and regulators are going around and spending those very limited resources without ever looking to see whether it actually makes sense. Is it the greatest carbon reduction for the buck? We don't know, because they won't even look at it. It's a politically-driven solution, and it doesn't make sense on either an economic basis or environmental basis, and it's one of the greatest lost opportunities to invest and make this country a really truly green country that I've ever seen. \$10 billion is going to be given to those aging nuclear plants to keep them afloat, and that's \$10 billion that's not going to be spent on wind and solar and storage and other distributed resources.

Question 10: Speaker 1 put up a slide that said that 30 of their largest 50 customers want 100% renewables. Those are some big names. and he also mentioned military bases. So these customers have definite needs for energy products and services.

The way I understand it, customers want a utility option. They don't necessarily have to have those products and services from the utility, but they want a utility option. So I just want to put this back to the panel. What are you hearing

from those customers, and how are you meeting their needs?

Respondent 1: I think you're absolutely right. Our customers do want a utility option for renewables. Some of them meet those needs through the utility option. Some choose not to. And that's their choice to be able to do that. We just think it's important for the utility to be able to participate in that, and if the customer wants to choose the utility for it, that they are allowed to do so. Some have specific reasons for wanting to utilize the utility. Others are just looking for whoever can best meet the needs. And so, again, it comes back to personalization. Every customer's got a different combination of drivers and a different set of needs, and I think it takes, not only the utility, but also third parties, to collectively meet those needs.

Respondent 2: As long as the utility option is met through competitive procurement, I think everybody's happy. And as to what those customers want, they want assurances that their load is being met with renewable resources. The distribution company can both competitively procure for them, provide the integration services, and avoid cross subsidy paid for by other customers. This is a great role for the orchestra conductor. And what those customers are not doing is threatening to drop off the grid and run their own little utility sectors. Isn't that interesting?

Respondent 3: I would cite you to a Google white paper. Google is one of those companies that's committed to getting 100% renewable power. And they really do a wonderful job in their most recent paper explaining why green tariff programs run by utilities are a second-best option, and that they vastly prefer competitive markets for the procurement of green power.

Respondent 2: Right, but we could do both.

Respondent 3: Well, we could, but we come back to this dilemma. If it's not a natural monopoly, why is the utility offering a value-added service that the private market --

Respondent 2: No, no, I'm just saying the utility could do the competitive procurement.

Respondent 3: They could, but where the utility affiliate is competing --

Respondent 2:...without the utility affiliate competing.

Respondent 3: This is why the California model has been very, very good to NRG. We've won an incredible number of contracts out there, because the utility wasn't there, and we've provided incredible value to the consumer, as witnessed by the number of RFPs we've won.

We don't have a problem with the RFP model, but it needs to be done in a way where the utility affiliate isn't competing. You could have all the standards of conduct you want, but there is a perception, real or imagined, from our side that we will not get a fair hearing. So I think you come back, and you look at what the companies are actually telling us, the ones who want to do this, the corporate off takers, are telling you that green tariff programs are really a second best to being able to go out and procure in the market.

Question 11: I think we understand, on the wholesale side, that we need a security-constrained economic dispatch with nodal prices. We know that from all the work that Professor Hogan's done over 20 years and has taught us that.

And I think what needs to happen here is a similar sort of thing, with best practices, whether it's in a regulated environment like Southern, or

in a deregulated environment like a Texas or a New York. So I commend the panel for surfacing these issues, but I think, really, the hard work is still to be done, which is to try to synthesize this into something that regulators can use, because I think there is a lot of confusion out there and, looking around the room, there isn't anyone here, or maybe a very few, from the existing commissions who really have to make these hard decisions.

Respondent 1: I think the "More Than Smart" initiative in California is trying to tackle this. You've got the REV in New York that's trying to tackle this. You've got the Maryland and DC commissions, who have both, at various times, looked at this. I mean, it is going to be an all of the above, right?

But, fundamentally, it is a tough question, and there's a real concern, and I understand this concern, about recreating bureaucracy. We have a wholesale bureaucracy. Do we want to recreate that at the distribution level? We probably don't, right? I mean, I don't think we do. I don't think that's economically efficient, which is one of the reasons I come back to these programs that they run in New York, like the feed-in tariff on a geographically varying basis, where they sort of set a rate that makes sense, and then people can compete for that. To be that kind of model really is sort of a first step that a lot of states could do.

Obviously, we're big fans of retail competition, where the states could come in and take the utilities out of the default service business. Let us be the ones who do the billing, who do the customer acquisition and retention function. There's really no reason why the utility needs to do these functions; there's no natural monopoly on that, as ERCOT, obviously, has shown incredibly well. And then, if you do that, I do think you enable some of the customer innovation that would come from having a fully

competitive market where we're competing on things like who offers the best residential demand response program.

Competition, it's good, right? I mean I know I'm in a roomful of economists. I've got the easy part here. But I do think it's true.

Respondent 2: I just want to say that, as I said earlier, I'm very sympathetic to the challenges and the decisions facing distribution regulators. I think they're real and require knowledge of a lot of factors in the industry. And one of the things that I worry about is I understand that now the average tenure of a state regulator is under three years, and they're not necessarily coming in with any deep experience in the industry. So it's a little worrisome that there's this ramp-up time. There are big decisions. It's hard to see how this is going to work out in a lot of states.

Question 12: I'm going to use the earlier analogy. We have an orchestra. How come the orchestra leader is the only one that gets the music? You can't have an orchestra without the musicians having the music. And what this industry needs is open-access data, like we had open-access transmission, because that is one of the major barriers, in addition to deployment of capital, for us in competing.

For example, if you're curtailing a customer 10 times a day, that's a price signal that somebody should know about and come in and fix. And you have that data, and we don't. So I would say that you have an orchestra, and everybody needs the data, and nobody's talked about that today, and that is what is making the difference and the disadvantage between the competitive sector and the regulated sector.

Respondent 1: I will say that we aren't doing that. That was a hypothesis about what might happen, but I will say that, just in the last week or two, the hosting capacity on 100% of our

distribution circuits is now available online for everyone.

Questioner: But is there still the fiction that the customer data is so sensitive that only you can have it?

Respondent 1: In several of our territories, it's against the law for us to give out individual customer data. And so I don't know that it's a position that we have because we don't want to share the data. Rather, it's a question of law. It's not even regulation, in fact, in two of our jurisdictions.

Question 13: I'll be very brief. My question is about how much we believe in all of this. If we're moving to a world where we think that customers are responding to price signals, do we believe in it enough that we would change our planning standard and actually have those customers potentially face the consequence of basically being off the grid, so that we actually stop buying products for them, so that when the cloud is going over, guess what, the lights go out?

Respondent 1: I think that that's a very important question. The only thing I can do is look to the way, in our jurisdictions, the regulators chose to deregulate. They asked us to step up and be the standard offer service. And they clearly are not willing to let customers completely fall on their face when things don't play out right. And so, they want that safety net in the backdrop, and the utility is serving that purpose.

Respondent 2: From Southern's standpoint, there is a continuum, I think, in terms of reliability. Today, our regulators are very focused on reliability for those customers who want firm service. We have programs today that allow customers to voluntarily give up some of that

firm service. I think that will have to advance over time, but, at least today, customers do have the choice to differentiate themselves, and that's their conscious decision as to whether they choose to do that. The regulators, though, want to be sure that we are able to maintain reliability for all of those other customers who don't choose voluntarily to go on those programs.

Respondent 3: And there is an ethic of community, that is in tension with the notion that the unsophisticated and those without resources are going to be second class citizens for reliability purposes. I don't think regulators will stand for it, and I don't think they should.

Session Two.

Subsidies in Electricity Markets: Tilting at Windmills?

There are few, if any, resources used in electric generation that do not benefit from subsidies of one sort or another. Whether they be direct tax benefits, public funding, governmental guarantees, liability limitations, cross-subsidies built into tariffs and rates, or more subtle forms of subsidization such as unfairly differential regulatory burdens or risk mitigation mechanisms, subsidies of one sort or another pervade the electric energy market. How does the existence of these subsidies skew competition? How are these benefits used and/or exploited by their recipients? To what extent are the stated public objectives of the subsidy actually served? To what extent are otherwise non-economic assets made sustainable by the subsidies and at what cost, if any, to overall market efficiency? On balance, what resources are most benefited from the various forms of subsidies, and which ones are most adversely affected? Do competing subsidies level the playing field or simply raise overall costs?

Moderator.

This is a very timely topic. You may have seen the House Energy and Commerce Committee had a hearing yesterday about subsidies and energy markets. You may have seen that FERC announced a technical conference for May 1st and 2nd about subsidies and organized markets in the Northeast. You may have seen a lot of debates around nuclear plant payments in Illinois, New York, and coming soon to a state near you. And, of course, you heard our morning panel talk about that a little bit. So there's a lot of controversy at the State level, and now it's spilling over into the RTO and FERC level.

Speaker 1.

It's great to be here. The title of this session is "Subsidies in Electricity Markets." I'm going to start the panel off by trying to broaden that a bit and put subsidies in electricity markets in a broader context of energy incentives in general, looking at different types of energy, not just focusing on electricity, and looking at incentives as well.

We've got lots of different types of energy incentives. We have federal and state financial subsidies, like the production tax credit and the investment tax credit. We also have federal and state mandates for particular types of energy resources. And we have federal property incentives (primarily eminent domain) and state

property incentives (split estate laws, eminent domain, etc.). With regard to federal property incentives and state property incentives, we can also put siting authority, who's allowed to apply for that, and who makes those decisions in this category of property incentives. So for some of these things like federal and state mandates, its certain energy resources that may be preferred. And with some of the property incentives, sometimes it's focused on energy resources, but sometimes it's focused on particular players in the energy industry, where some have incentives and benefits and some do not. And then another form of energy incentives, of course, is limitations on tort liability. There's the Price-Anderson Act, in the nuclear context, and also the Oil Pollution Act, in the oil context.

I'll talk first about financial subsidies, and, as I said, others on the panel are going to talk about this in much more detail, but we're talking about federal tax subsidies and grants. We're talking about state tax subsidies and grants, and also research and development money and loan programs. So these are obviously a major, major energy incentive across all sorts of energy resources.

Now I put this slide of the "historical average of annual energy subsidies," up, not because these numbers are accurate (they can't be accurate if we're going back to 1918, and they're also not through the present), but I put it up only for

scale. We have so much focus these days on subsidies for renewable energy because, as of now, renewables certainly get the bulk of the federal energy subsidies, but, of course, if we look at subsidies over time (because we've been having energy subsidies for oil and gas and for nuclear for a much longer time), those numbers for total subsidies for non-renewable energy are bigger. Are they bigger in these exact amounts? No. But they still are bigger, simply because they've been in play for such a longer period of time. We often focus on the last 10 years or the last 20 years, but these types of subsidies, these types of incentives, have been in play for a very, very long time.

Moving from subsidies to mandate, we have a lot of state and federal mandates for particular types of energy resources. We have the Federal Renewable Fuel Standard for ethanol, which is clearly a major incentive and benefit to that industry. We have state Renewable Portfolio Standards. We have the Renewable Energy Credits at the state level, and now, as a result of recent legislation and regulatory activity in both New York and Illinois, we also have zero emissions credits on the nuclear side, which I'm sure we will talk about in more detail on this panel. We've got PURPA and state and local feed-in tariffs that provide certain types of mandates for particular types of energy resources. We have net metering, particularly on the solar side, and also energy efficiency resource standards, which, in some ways, go the other way, because you're going to have less electricity, but it still is a mandate, at least on the utility, in many states.

And then we've got liability limits. Certainly there is an incentive and some type of subsidy provided by limiting tort liability for nuclear or for oil pollution. So these need to be included as well when we're talking about our big picture of energy incentives.

And most people may not think of property rights serving as energy incentives, but, clearly,

they do. So, for interstate natural gas pipelines we have Federal siting and eminent domain authority for this type of energy transport infrastructure. It makes it easier to build. That's why it was enacted in the 1930's. It provides a significant benefit for building that type of infrastructure. There was an effort in 2005 to get eminent domain authority for LNG terminals. The act did not pass, but there is federal siting authority, and, of course, you can say there's not as much need for eminent domain for LNG terminals, because it's a fixed site. You don't need to cross multiple states. But that still was something that was in play in that legislation.

As everyone in the room knows, we have very limited federal siting or eminent domain authority for interstate electric transmission lines. You have federal siting authority when transmission crosses federal lands. If you have federal projects under Section 122 of the Energy Policy Act of 2005, there is perhaps federal siting authority and eminent domain for projects that DOE partners on with private parties, but that is in litigation right now, and we will see what happens

There's no federal siting or eminent domain for interstate oil pipelines. There was for a short period of time during World War II. The Germans were bombing the ships going up the East Coast, but South Carolina and Georgia said they didn't want these oil pipelines that were going to be built as a substitute, so Congress did create Federal siting authority and eminent domain authority for oil pipelines during that time, but the legislation sunset at the end of the war, and we went back to state by state siting for oil pipelines.

I would argue that for oil pipelines you actually don't need siting authority as much as you do for electric transmission lines, simply because we have multiple ways of transporting oil in this country--by ship, by train, by pipeline. So, to the extent you're comparing oil pipelines and electric transmission lines, I don't think they're

quite equivalent, just because the resource is different.

And then we have energy incentives at the state level as well. So, we have split estate laws for oil, gas, coal, and minerals that allow the mineral owner to be the dominant estate and to be able to interfere with the rights of the surface owner to access those minerals. We have eminent domain for utility-sponsored electric generating facilities. That's not used that often these days, but a lot of state legislation is broad enough to encompass generation facilities. Some states have carve-outs to confirm that you can't use that authority for wind, although not all. And we have state siting and eminent domain authority in just about every state for utility-sponsored electric transmission lines, but not necessarily for merchant transmission lines. That differs state to state.

And then we have what I would call some energy disincentives. There's a moratorium that's been proposed in the North Dakota legislature to say no new wind development in North Dakota because it's competing too much with the lignite coal industry in North Dakota. So no more new wind for two years. We'll see what happens with that. That is certainly a disincentive for particular energy resource. Also in State legislatures this spring, we have new taxes proposed on wind generation in Wyoming (which already has a severance tax on wind, but they're thinking about increasing it), and also in some additional states as well: Oklahoma and South Dakota. Again, these state are concerned about competition with oil and gas industries. More states are proposing user fees on electric vehicles, based on the argument that electric vehicles are not paying their fair share of road use, because they don't pay the gas tax, so the states will charge \$100 a year, or \$150 a year. One of those is pending in Minnesota right now, and I think Virginia has a user fee, and several other states do as well.

Many states do not allow merchant transmission lines to get siting certificates within the states or to exercise eminent domain authority. And recently we've had state pushback against eminent domain for oil and gas pipelines in Georgia and South Carolina, which, I guess, have a history of not liking pipelines going through their state, as we talked about, during World War II. Both states have enacted moratoria on eminent domain for oil pipelines.

New York has had its own state pushback against fossil fuel infrastructure with regard to the Constitution Pipeline. I'll show a map of that in just a minute.

And an older sort of throwback case is Minnesota, which has a unique "Buy the Farm" law for electric transmission lines. There were some controversial electric transmission line projects in the 1970's, and so when the utility goes in to use eminent domain for a transmission line project, the land owner has the option to say, "No, you can't just take an easement, you have to buy the entire property." And the Minnesota Supreme Court recently confirmed that the law says what it says under challenge.

So, to talk about some of these property incentives and disincentives, I want to focus on some of the Clean Line projects. So, the Plains & Eastern Clean Line project, which goes through Arkansas and Missouri and some other states, was granted certificates in a couple of states, but then in Arkansas, the Arkansas Public Utility Commission denied a certificate and said, "Our legislation is not set up for merchant lines. If you do not have retail customers in the state, you can't get a siting certificate." And so the Plains & Eastern Clean Line applied to DOE under Section 122 of the Energy Policy Act of 2005, to partner with the Southwestern Power Administration to build that line, which maybe provides them Federal siting authority, overriding Arkansas' denial, and also may provide Federal eminent domain authority. We'll see what the courts have to say about that,

but you see that certain types of transmission builders have incentives, through property law, to be able to more easily build these lines, but if you have a different type of electricity, they don't necessarily have those same incentives. And with the state by state approach, that makes it difficult.

Last week there were hearings on the Grain Belt Express line further north. That's one where Iowa had said yes. Illinois had said yes. Missouri had said no. But then Clean Line worked out a deal with some of the municipal utilities to provide them with very inexpensive wind energy. The municipal utilities now say that they are now in favor of the line, and so in Missouri, the Public Service Commission is holding new hearings and had a trial last week. We'll see what happens with that.

I put the Constitution Pipeline up here on my slide only to show that because of federal siting authority, interstate natural gas pipelines have it easier than interstate electric transmissions lines, in terms of dealing with state boundaries. That doesn't mean they always win. New York has a big pushback against fossil fuel infrastructure. They have said no, under the Clean Water Act. But I would say that's more the exception than the rule. So, by having Federal siting authority as opposed to state siting authority, you make it easier. It doesn't mean that every project sails through and isn't expensive. But there's a big difference, depending on where those incentives are created as a result of federal law.

Do we see any shifts in energy incentives in the Trump administration? I thought it was interesting that the morning panel today could have been given before the election. No one really mentioned any changes with regard to there now being a Trump administration. Which is actually not surprising, but at least worth noting.

There's been a stated emphasis on infrastructure. We heard that during the campaign. We have

heard it, from time to time, since the election, but what does that really mean? Are we actually going to see an expanded eminent domain authority to try to build some of this infrastructure, or expanded Federal siting authorities for transmission lines or for pipelines? I don't think so, but that is certainly something that may be talked about.

Will we see less environmental review to speed up some of these projects? Perhaps. More limits on liability? I don't know. Where are we going to see current financial incentives go? Is there going to be less for renewables, more for nuclear, more for CCS, or just less money for everyone? We might see increases in financial incentives for oil and gas development and infrastructure. I think very likely we will see less research and development money overall, and less on the loan programs. I think that's a pretty safe bet. I will stop there.

Speaker 2.

Thank you for the invitation to be here today. I am excited to have a dialogue with this group after the presentations to get your feedback on where tax policy for the energy sector should go.

I'm going to talk about three things in my few minutes here today. The first thing I'm going to talk about is the history of tax-related support for the energy sector broadly. And then I'm going to talk a little bit about the changing energy tax landscape. What's happening under current law, and what might potentially happen in a tax reform debate? And I do want to spend a little bit of time talking about tax reform--what tax reform can mean for the availability of the existing energy tax incentives, but also broader tax reform issues. Sometimes I find that when you're looking at tax reforms for a specific sector of the economy you look at the targeted tax preferences for that sector when it really matters more to think about the big picture and big overarching structure of the tax code.

The first slide here that I want to spend a little bit of time on is the value of energy tax incentives over time. And this chart goes from 1978 up through projections under current law for 2020. And to be clear about what this figure includes, it first includes the value of tax expenditures, sometimes called “spending through the tax code.” Really, tax “expenditures” are the revenues that are not collected, due to what are deemed special provisions in the code. So tax expenditures can be credits, deductions, accelerated cost recovery, special tax rates, anything that the Joint Committee on Taxation (which estimates these tax expenditures) deems is a deviation from what is the normal tax system. This figure also includes the value excise tax credits, and this is mostly for fuels, through 2011. These were incentives for ethanol, and now they are incentives for biodiesel and renewable diesel. This figure also includes Section 1603 grants that were given in lieu of the investment tax credit and the production tax credit.

As I mentioned, this chart shows the value of tax incentives under current law. What that means is that, for the out years, this may change. You can see that the renewable fuels incentives are expired, so in the out years there’s no renewable fuels incentives. A number of the efficiency incentives for residential and commercial building energy efficiency are also expired. So if those are extended, you would not see those in the out years. There’s a lot of talk about what incentives may or may not be extended, and that will be an interesting debate come the end of this year, and in future years for other incentives as well.

So looking at this figure through the mid 2000’s, most of the support was for fossil fuels. There was a little bit of support for renewables in the 1990’s and 2000’s--that was for ethanol, and a little bit in the 1980’s was available for renewables. But beginning basically after the Energy Policy Act in 2005 and then again after the Stabilization Act and the Recovery Act it

shifted. Now renewables, through Section 1603, the investment tax credit, and the production tax credit, received the bulk of the share of Federal financial support for energy that’s delivered through the tax code.

One other thing that doesn’t stand out in this chart that I think is important to mention is the number of provisions that are designed to support the energy sector. So in 1987, right after the 1986 Tax Reform Act, there were six provisions that were deemed by the Joint Committee to be targeted for the energy sector. When I counted up what there were in 2016, there’s roughly 30. So you have all these kind of narrow, specific targeted incentives for different parts of the energy industry. And so I think that’s something that’s important to keep in mind.

One other thing that I think is helpful in the context of tax reform is to remember that the value of tax expenditures that are deductions is a function of tax rates. So it looks like there’s a drop off in tax expenditures after the 1986 tax reform. A lot of that is a consequence of the reduction in tax rates that happened in the 1986 tax reform, because the provisions that were available for oil and gas were for cost recovery.

This next slide here shows how the balance of tax incentives would change over time under current law. In 2015, there was roughly five and a half billion dollars for fossil fuel incentives, there was close to eight billion dollars for renewables, and then less for renewable fuels and residential energy efficiency. The 2020 column of this chart shows incentives under current law, no extension of expiring provisions. Most of the renewables incentive, again, is the investment tax credit and the production tax credit, and these are under the long-term extensions that were enacted at the end of 2015. And then at the top there’s a little bit for plug-in electric vehicles. And then in the third column here, what I’ve done is I shaded out incentives that are scheduled to expire, leaving kind of a

carry-forward with the production tax credit, since you get the incentive for 10 years after the facility comes online.

This really kinds of illustrates what incentives are available for new investment, versus what are kind of legacy incentives. What are things that are just hanging around? And that's a really important point when people say that in 2020 renewables are still getting the bulk of the energy tax credits. There's not a lot there to drive new investment. A lot of it is kind of legacy.

Looking at expired and expiring provisions, I think most folks in this room know what's happening to the investment tax credit for renewable electricity. Something that's worth noting is that there's a permanent 10 percent credit for solar on the business side, but the credit for residential investments in solar is scheduled to expire. It's also worth noting that the 10 percent credit for solar that's available on the business side is one of the few permanent features of the tax code. It's something that doesn't have a sunset provision that supports the renewable electricity sector.

And then, for the production tax credit, the phase out has begun this year. PTCs for projects that begin construction this year are subject to a 20 percent reduction.

It's also worth noting that the long-term extensions for the energy credit and the production tax credit that were enacted at the end of 2015, were only for wind and solar. There's a debate on the Hill about whether that was intentional or not, and whether the technologies that are or were otherwise eligible for the production tax credit should see the credit extended. That includes certain biomass, hydro, municipal solid waste, for example, and then, on the investment tax credit side, there's a debate as to whether the tax credits that support investments in fuel cells and combined heat and power should be extended.

Some of the other incentives that have expired are for biofuels, alternative fuels, and residential and commercial energy efficiency. They expired at the end of 2016. You can do retroactive extension through the end of this year. Whether or not Congress chooses to take on a tax extenders bill and address these expired provisions this year is something that I think is likely to happen and is kind of flying under the radar right now. There's a lot of focus on tax reform, but if tax reform doesn't happen, there are 32 temporary tax provisions that expired at the end of 2016. A number of those are in the energy sector. Congress will then likely turn attention to whether those should be extended, and most of those provisions have been extended in the past.

A question that I get asked a lot, and that I don't think is necessarily the best way to look at how the tax code supports energy, is, how do we compare the value of energy tax incentives to production from different energy resources? And in order to make that comparison, we just have to look at primary energy production by source. And I use primary energy production instead of electricity, because for a lot of the tax incentives it's hard to identify how much of them support electricity, as opposed to other energy activities. And so this pie chart is just EIA data from 2015, showing primary energy production by source. Having that data facilitates an analysis where we can look at the value of energy tax incentives for two different energy resources.

Now, as I said, I don't think this is the best way to look at this from a public policy perspective and there are a number of different reasons, but I'll just discuss a couple. One is that the current year incentives don't necessarily support current year production. So for solar, with the investment tax credit, you're getting 30 percent of your capital cost that's coming upfront, for facilities that going to be producing solar electricity over a longer period of time than that year. So, you have a timing mismatch between

when incentives are delivered and when electricity is produced and consumed. And also, different levels of federal tax subsidies don't tell us much about the policy rationales behind them. Higher levels of support for renewables can be used as an alternative to a price on carbon. So we're not thinking about why the levels of support might differ.

That said, it's a question that comes up a lot. Fossil fuels are associated with 80 percent of primary energy production and received about 34 percent of tax incentives in 2015. Conversely, renewables had a share of primary energy production of just under 11 percent and received about 60 percent of federal financial support.

I mentioned that there are lots of incentives for energy in the code. Some of the other provisions don't show up in those numbers, because they haven't had an effect on reducing tax liability, yet are things like the Advanced Nuclear Power Production Tax Credit or the Credit for Carbon Dioxide Sequestration. The nuclear PTC was enacted in 2005, and hasn't yet been claimed. There are some estimates that it could be worth up to six billion dollars for the industry, for reactors that are under construction.

And so, when Congress embarks on tax reform, will some of these parameters for the Advanced Nuclear Power Production Tax Credit be changed? Will the "placed in service" deadline be changed? Will the 6,000 MW national capacity limitation be removed? Or will the credit be left as it is, or will it be repealed?

And the same thing for the credit for carbon dioxide sequestration. The Obama administration in their budget proposals had proposed expanding this, and there's certainly been interest from certain members of Congress, too. Those are open questions.

Another thing that is important to note here is that cross-cutting subsidies or cross-cutting tax provisions are not included in this analysis, and

these can be very important for the energy sector, as well as other sectors of the economy. And one example here is the domestic production activities deduction. It's a deduction of nine percent of taxable income that is available for electricity production, or it's a deduction that's limited to six percent for oil and gas-related activities. The Section 199 deduction is available for about one third of all taxable income in the economy. So for anybody that's a domestic manufacturer, it serves to reduce their effective tax rates.

Now, this is really illustrative of the tradeoffs that are associated with tax reform. If you were to eliminate the domestic production activities deduction, the 199 deduction, for everybody, for all qualifying activities that affect about a third of the economy, but then you give rate cuts to everybody, not just that one third of the economy, the effective tax rates for tax payers who previously were claiming the domestic production activities deduction are going to go up, even though statutory rates have gone down. So that's an illustration of the tradeoffs that will come up when more details on tax reform come out.

Another provision that's cross cutting is bonus depreciation cost recovery, and how cost recovery is done is a big issue for tax reform right now, too.

When we look at tax reform, the conversation up until now had been to look at a base-broadening, rate-reducing tax reform in the spirit of 1986. In 1986, there was a fair amount of scope for rate reduction. Individual rates were reduced from 50 percent to 28 percent. Corporate rates were reduced from 46 percent to 34 percent. There was a lot of room to come down on those rates, and the base was brought in, so that the tax reform was revenue neutral. It didn't add to the deficit over time.

Chairman Camp, when he was Chair of the House Ways and Means Committee, put together what was a really thoughtful piece of

legislation on tax reform. The details were spelled out. It was in legislative language. It was clear what was going to be done if that proposal was enacted. And what that proposal proposed to do was to eliminate most energy-specific tax provisions, with notable exceptions, and those notable exceptions were primarily related to cost recovery in the oil and gas sector. Expensing of intangible drilling costs would have been retained. Two-year amortization for geological and geophysical expenditures would have been retained. And I think the deduction for tertiary injections would have been retained. But percentage depletion, that would have been eliminated. And it proposed to reduce corporate and individual tax rates.

But what happened when Camp released this proposal is the tradeoffs were exposed. Something else that's notable about the Camp proposal is what it did to cost recovery. Camp generally increased the asset lives for the purposes of cost recovery. So revenue was raised by lengthening the amount of time over which costs were recovered using depreciation, and that allowed for rate reductions in a revenue neutral sense.

The House Republicans, this past summer, released a blueprint for tax reform, and it's a blueprint. It's not in legislative language. The details are not spelled out, but the big picture, the overarching parameters, are. And in that reform, it's proposed to move to a top corporate rate of 20 percent, and then business tax pass through would have a top rate of 25 percent. Now, the blueprint says that the goal is to repeal special interest business tax provisions. These are completely unspecified in the blueprint, but one can imagine, if you looked at what would be talked about here, that it would be energy tax expenditures.

A lot of the renewable incentives are set to sunset under current law. Secretary Mnuchin did indicate that those will probably sunset as

scheduled, but things like the permanent 10 percent investment tax credit could go.

The other major innovation, and this is a really, really stark deviation from current practice, would be to move to a business "cash flow" tax. All capital investments would be expensed, so the cost would be deducted up front. That means that any provision that's in the tax code that's associated with cost recovery would more or less be mute. It wouldn't matter anymore, because you had expensing for capital investments. Also, there'd be no deduction for net interest expenses. So this is really important for debt financed capital investments, something that I'm sure is important for this room. And so that's a big tradeoff and there's a lot of utilities that are saying, "If we're looking at this, and we're trading expensing for the loss of net interest expenses, is that a tradeoff that makes sense for this industry?"

And then, finally, there's this border tax adjustment. The House Republican blueprint moves towards a cash flow tax which is something that is more like a consumption tax, moving towards the model of value added tax, but a deduction for wages is retained. So, by retaining a deduction for wages, it's not a true value added tax, and there's some question about whether this border adjustment mechanism that's included in the proposal would pass muster with the WTO. (But I will set that aside, since I'm not an attorney.)

The border tax adjustment idea would exclude receipts from exports. There would be disallowed deductions for imports, and that would remove the incentive for multinationals to shift profits abroad artificially. But it also could have some implications for importing and exporting activities. Economists will say that exchange rates are going to adjust, and this is all going to kind of wash out, but there's a lot of uncertainty surrounding this part of the code.

I want to close by discussing briefly the overarching framework in which I think it's helpful to think about these things. Why do we impose taxes in the first place? I'll have this conversation with Congressional staff, and they'll say, "Oh, well, we use the tax code to create incentives. We use it to drive activity." No, we use the tax code to raise revenue. The basic purpose of levying taxes is to raise revenues. Being able to then change taxes and kind of drive economic activities is something that's secondary.

So, why do we have these tax incentives? One of the key reasons is to address externalities, for example, to address unpriced pollution externalities from fossil fuels. Now, historically, in the United States, we've used subsidies to do this. It's kind of a backdoor policy. It's less efficient than taxing the externality directly. If we use a subsidy approach, then more revenues need to be raised elsewhere to meet that fixed revenue target. So you might have higher taxes on labor, you might have higher income taxes, something along those lines.

Another externality is learning-by-doing knowledge spillovers. If we have an industry that's ramping up, we want to encourage investment in that industry, especially to the extent that their learning can benefit others.

There are a couple of key challenges to using tax subsidies in the electricity sector, and the first one here I alluded to already. When you use the subsidy approach, you're reducing prices overall. So that runs counter to energy efficiency objectives, and it can distort other market signals. And it doesn't address the negative externality associated with fossil fuels. You're not pricing that directly.

Another issue, one that I think is not discussed as much as it should be, is the fact that a lot of taxpayers have limited tax liability, and so they're in a space where they're already generating tax losses. They don't have any

scope, any ability to monetize tax incentives directly, and so they turn to tax equity markets. And that means the tax code is not a particularly efficient way of delivering Federal financial incentives to them. I am going to close there.

Question: I think you said there was an evergreen tax provision for solar, but not for residential solar. Is there a size associated with that, or any kind of descriptor other than nonresidential?

Speaker 2: It depends on whether you file as a business or as an individual tax payer.

Question: On your slide six, the reference to fossil fuels, does that refer to incentives for pipelines, not for generating facilities or excavation and fracking or any of that? Is that correct?

Speaker 2: It includes the expensing for intangible drilling costs, percentage depletion allowance, the ability to structure as a master limited partnership, and some of the alternative fuel incentives that go towards natural gas.

Question: In the House version of a border tax or variations on that, is electricity considered to be a good or a service?

Speaker 2: I don't know. Things are just not spelled out that much. If you look at the House proposal and what is there, it is a paragraph that says that we will adjust taxes at the border.

Speaker 3.

I want to start off by thanking Ashley and Bill for giving me the opportunity to talk to you about some research we've done on the impacts of subsidies in the power markets.

The first point here is that these subsidies that we're talking about are all very, very complex. When I talk about subsidies with people, I'm often confronted with a very simple idea--that subsidies are simply providing a nudge to

accelerate changes that are kind of inevitable in power markets, and I don't think that's really the case at all.

The other thing that happens when you talk about subsidies is that there's a lot of resistance to looking at any particular subsidy, because people think that, because there's so many other things that are subsidized, it's not fair to pick on one subsidy without evaluating them all. But I think what Speaker 2 showed was that this production tax credit for wind is one of the largest subsidies that we've got in electricity markets, and what my research is saying is that it's also having some of the biggest distorting impacts on electricity markets. And even though they're being phased out, you have to remember that if you complete these projects before these deadlines, you've got the PTC for 10 years to come. So this is a distorting factor that's going to be with the marketplace for a decade or more. looking forward.

When I look at the production tax credit on wind, the impacts are that it suppresses wholesale electric energy market clearing prices. It reduces investments in efficient generating capacity. It frequently subverts the original intent of the subsidies, and then generates arguments for offsetting market interventions.

In order to try and explain how I get to that conclusion, the best way, I thought, was to give an example. I'm using ERCOT as an example here. ERCOT's a market that has got an awful lot of wind. Wind there provides between 12 and 15 percent of annual generation. In some hours it can produce as much as 50 percent of electricity. So if we look at this pattern of subsidized wind that we've seen introduced into the ERCOT market, we can start to understand what kind of impact it's had on the market outcomes. And it's important to think of this annual, real time pattern of wind production, because power markets clear demand and supply in real time. So the distortions are very much related to the time pattern.

So this slide shows the time pattern of electricity demand in ERCOT. And this is a recurring annual pattern of electricity demand, and why that's important is because the real objective here in the electricity market is to create market clearing prices across a year, so you'll get a recurring pattern of electricity prices that give you the right signals, so that you can supply electricity in the amounts and when people want it with the most efficient supply mix.

And so, to analyze the impact on the marketplace, I wanted to draw some curves to show you the intersection of supply and demand in ERCOT. Now, I picked 2014, because it's a year with less surplus supply than what you currently have in ERCOT, but it's a good representative year. There's nothing unusual or unique about 2014, and, similarly, what I'm showing you here, I think, applies to other markets besides ERCOT. The supply curve here is the aggregation of power supply from rival generators who profit-maximize by dispatching whenever the price equals or is above their short-run marginal costs. So it's a classic short-run marginal cost-based supply curve from an economic textbook. Now, what's a little bit different here is, although wind is technically electricity supply, since this isn't a short-run marginal cost dispatch kind of supply, what I've done is I've treated wind as something that's subtracting, shifting the demand curve. So those solid vertical lines there are the demand curve that you saw previously, showing peak demand, average demand, and minimum demand, and then the leftward shift shown by the dotted lines is taking the aggregate demand from customers and subtracting out the output of wind. So now I'm looking at this intersection between a market demand curve, which is net load, and the supply curve, and this gives you a sense, then, of what's the difference, in this market, of having the wind versus not having the wind.

In today's first panel, one of the speakers said that the important thing is long run efficient

price signals, and that's what we're really trying to focus on. And so, when we look at this, what do we see? We see that wind is disproportionately in the off-peak periods. So, you can see the big shift there in that minimum demand line, because we get more wind in the off-peak period and when you look at what is it doing to the market clearing price of electricity, you can see it makes a big difference, even though there's not a lot of it on peak. Given the shape of the supply curve, a little bit of a movement at peak demand can lead to a pretty big drop in price. It doesn't affect the average price a whole lot, when you look at average demand and the way it shifts over a relatively flat part of the curve. And then it affects the off peak, the minimum demand periods, quite a bit, given the shape of the demand curve.

Does this really represent what's actually happening in the marketplace? Well, the average hourly price in ERCOT was about \$36 a megawatt hour in 2014. You can see how that does reflect that intersection point there, on average. So it does kind of line up pretty well and explain the level and volatility that we saw in competitive prices throughout the year.

Now, the key question here is what kind of price signals these prices are presenting to the supply side of the power business. And so, when you look at what you want a well-functioning market, you want the prices to be clearing at levels that will incent the efficient mix of generating technologies. So, when you look at, for example, the highest prices here, you want these highest prices to be able to support the investment in the technology that gives you the most efficient electricity supply when you're not going to run something a whole lot. That's going to be a peaking unit. If you're going to run something to meet loads that you're not going to see more than about 20 percent of the time, you want the market to have price signals to build some combustion turbines. In ERCOT in 2014, the combustion turbines ran about 16.4 percent of the time. You had a realized price there of

about \$77 a megawatt hour. The all-in cost for a new CT in Texas is more like \$111.

What we saw, then, was on-peak power prices that were probably a little bit lower than what they need to be to support the CT. Now, it may be that we still had a little bit of surplus supply in 2014. It's not unusual that on-peak prices don't support the long run marginal costs of a peaker, which is why you've got all sorts of market interventions like capacity markets, or, in the case of Texas, the operating reserve demand curve (ORDC). The ORDC takes the loss of load probability times the value of lost load and creates an additional adder to give a price signal.

Now, when you get rival generators competing to supply the peak load, competitive forces are going to drive them to invest in things like combined cycle, because they realize that if CTs are clearing the market 16% or 20% of the time, then you've got a difference between what the market price is and variable costs. So that cash flow from the energy market can pay for the additional investment in more efficient electric production. So you've got a price signal here that's driving people to invest in more productive, more efficient electric production capacity. And when rival producers are competing to serve that load that you're going to see most of the time, what you get is competitive forces looking at those cash flows from the energy market and forcing people to trade off some flexibility in the generating technologies for even greater efficiency. So it's things like cogen and base load coal and nuclear plants that are getting a price signal.

So what we expect, then, is that in a well-designed, unfettered competitive electric marketplace, the intersection of supply and demand across a year should produce varying hourly price levels that drive investment into this mix of generating technologies with different costs, different efficiencies, different operating characteristics that all together produce the lowest total average cost to meet this recurring

annual aggregate net load pattern. So that's the market result.

In that case, if it makes sense to build wind and introduce it, we expect that you'd have an economic, unsubsidized wind entry, and it would occur when those price patterns are high enough that during the period when the wind is blowing and you can generate that market clearing price, there is enough to cover the NPV of that wind investment.

When we look at the case of Texas, and we look at the costs and so forth, what we find is that the unsubsidized cost of wind entry is between \$38 and \$100 per megawatt hour. That's an estimate from University of Texas, Austin, back in December of 2016. As I said, the market clearing price, on average, is below that, and since wind blows most off peak rather than on, off peak, the average is \$27. So, if you had an unfettered market, you'd have little to no investment in wind generation in the Texas market. And that doesn't include the cost, the \$6.3 billion that was incurred to build the transmission lines to these CREZ zones to make it happen.

So, what do we see has happened in Texas? We've seen that we've had the subsidized large amount of entry. It's more expensive than what the unfettered marketplace would be, and for the remaining generation that the dispatchable resources have to supply, we're ending up with investment in less efficient, more expensive generation.

Now, you could argue that this is the second-best outcome, and that the market prices are signaling an adjustment in the technologies on the dispatchable side that give you the most efficient supply, given the amount of wind that you want. But here's the bigger problem. We're not even getting the second-best solution in Texas, because we've got so much wind in that off-peak period that we get over generation conditions. And at that point in time the

production tax credit gives wind a marginal cost of a negative \$23 per megawatt hour, because you don't want to not generate and give up the production tax credit. That doesn't reflect real resource costs. So we get a very inefficient curtailment and adjustment of resources during the off-peak period. So we end up with a less than second best outcome.

What is the consequence of all of this? The consequence is that we're suppressing the cash flows for intermediate and baseload power plants. The suppression at off-peak times is not a big problem, if we've got something like ORDC to fill in. So we're worried about the load-following assets, and what we're seeing in markets around the U.S. is, we're seeing uneconomic baseload power plant retirements. And this is a story that we see across the U.S. We see it with nuclear units, in particular. So you're not even getting the original intent of the renewable support, which was to reduce CO₂, because, if the consequence is to prematurely close down nuclear plants, you end up like California. Despite all the growth in renewables, the state's CO₂ emissions haven't gone down.

And it isn't just California. Look at New England. This graph shows their electricity carbon footprint. With the closure of the Vermont Yankee nuclear station in 2015, CO₂ emissions went up seven percent instead of down and now they've got Pilgrim going down.

So we've got this perverse outcome that subsidies are suppressing the cash that supports these baseload units, and it's increasing CO₂ emissions. And if we look at what's under construction to replace these premature closures, we're building about two megawatts of gas with every megawatt of wind, and if you look at what that means, if we close down a typical coal plant along with a typical nuclear plant and replace them with what our current replacement power looks like, we actually increase CO₂ emissions with that wind and gas combination to replace

the closure of baseload coal and nuclear in these proportions.

So the bottom line here is that we've got subsidies that really undermine the efficient outcome in power markets, and the situation is likely to be undermining the political support for markets in general and creating a terrific need for subsidies to counteract the distortions of the subsidies that have been introduced into these markets, and it's a very, very complicated slippery slope that we seem to be going down.

Question: Does it make any difference whether there's a capacity market or not, in terms of the analysis that you presented?

Speaker 3: I think that the similarity of a Texas market to a Northeast market makes it pretty clear that with either the ORDC or capacity market, the real problem in price suppression isn't investment in peaking assets. It is the other assets we need in the mix. So, no, I don't think whether you've got a capacity market or an ORDC really affects the basic argument here.

Question: Can you just clarify, what other ISO services are you looking for that are missing?

Speaker 3: What I'm saying is that you want price signals in a marketplace to signal investment in the most efficient mix of generating resources to give people the electricity they want when they want it in the most efficient way. So if we suppress the prices across all the hours, but we've got a mechanism like a capacity market (and, if you'll remember, the capacity price is typically a net CONE price, so it's cost of the new entry of a peaker, less the contribution from the energy market), we've got a mechanism such that we're not worried about investment in reliability as much as we are investment in efficiency.

Question: Is there an easy way to understand where the breakeven would be? You've about 20 percent wind there and an 80 percent gas mix. Is

there some point (like 30 percent wind?) in which that becomes a carbon positive story, if we have sufficient renewables?

Speaker 3: Yes. With the coal plant and typical nuke plant, the breakeven was around 30 percent wind.

Question: You showed data from in-state generation in California and made the point that emissions haven't fallen. That's kind of an apple to oranges comparison, because the RPS applies to total procurement from the utilities. Do you have a sense for how emissions of imported plus in-state generation have changed over the same time interval?

Speaker 3: Yes. So that data that I showed you is from CARB (the California Air Resources Board) about in-state generation. And what's interesting is, as renewables have increased through time, so too has gas generation. So, over the past 12 years or so, gas went from being 50 percent of in-state generation to 60 percent. So, when you close down San Onofre, and replace it with gas and renewables, your CO2 emissions go up.

As far as out-of-state generation imported to California, CO2 emissions have gone down, largely due to the shale gas revolution creating a substitution of gas for coal. CARB does some pretty squirrely accounting things to come up with the CO2 content of imported electricity. So it doesn't really give you a reliable indicator, but, basically, all of the CO2 emissions reductions in California that we've seen across the past dozen years comes from what's happened outside of the state, not what's happened inside of the state.

Speaker 4.

Let me also begin by thanking Bill and Ashley for the kind invite. My remarks, I think, may be a useful addendum to Speaker 3's comments. I'm going to present a case study on the impact of the investment tax credit (ITC) in particular,

but also the impact of accelerated depreciation, in terms of how it has led to the formation and success of the residential business model for solar PV.

To begin, we're in a period where we're seeing secular growth in solar, and of course in wind, across the country. Unlike almost any other energy technology, solar PV's technical efficiency is scale invariant. So, this provides us, then, with a pathway for deploying generation at all scales effectively. That is, solar PV is equally functional at all scales from a technical point of view, though there are economies of scale to consider. And that's beginning to play out, of course, in the growth of DERs. The net of all of this is that, today, about 60 percent of our PV capacity is captured in a relatively small number of large utility-scale, ground-mounted facilities. And then the balance is more or less evenly split across larger commercial rooftop-type facilities and individual residential facilities.

And, of course, that growth in capacity has led to very, very strong growth in generation. Surprisingly enough, we have four states now where more than six percent of total generation is coming from solar, with California in the vanguard. Obviously, Hawaii and Vermont are significantly smaller states, but nonetheless we are seeing these numbers creep up. And even in my own state, in Massachusetts, we've seen robust growth. And these levels, particularly the California level of penetration, are leading to a range of challenges for the system, technically and in terms of integration, and so on.

And this high penetration of solar is leading to exactly some of the challenges that Speaker 2 was speaking about with respect to the market impact. Over the past couple of months, the actual value of solar generation on the wholesale market in California was under \$20 per megawatt hour. And that was putting a lot of the gas units there into a position where they were running at negative prices for a few hours in the middle of the day to avoid the startup cost of

coming back on in the afternoon. So this is the story that's going to be an increasing challenge for the wholesale markets.

I'm going to focus most of my remarks on the residential space. There are some salient takeaways that are beginning to emerge about the future. First and foremost, we're at a point today where there are over a million individual rooftop systems, mainly residential systems, in the United States. And I think what this has done is, it has revealed that residential customers are quite smart in many instances where they see value for money from their own perspective. They're willing to seize on that. And that value for money is coming from a range of topics that we're discussing here.

The value of the energy or the cost of the technology itself is slightly removed, in some instances. But what's important about that story, particularly on the residential side, is that it reveals the fact that solar is not one homogenous business. We have bookends here, and on one end we have the utility-scale business, where in California, for example, you have a kind of a monopoly arrangement. Large utilities procuring large volumes of solar energy. And actually what we see in that respect is that the pricing of PPAs that are being signed is really very reflective of the costs of the physical plant adjusted for the subsidies and so on, that are in place. And, frankly, it's not a very good business to be a developer in that space.

By contrast, the residential business is more nuanced. First and foremost, there's asymmetry in information between consumers and developers. And there's also a different kind of pricing benchmark for consumers. And that has led to the emergence of the residential business leveraging what we term "value pricing." So, effectively, they're offering you solar energy in a manner that feels like value to you relative to, for example, your incumbent utility rate. And a range of players in the market, although a surprisingly small number, really, have actually

been able to seize on this and drive forward in delivering these products at scale in a manner that is leading to some interesting financial innovation.

Now, from a consumer point of view, and from the point of view of somebody who thinks that certainly DERs do add value in certain instances, I think this is a very interesting development, because the innovations that companies like Solar City, Vivint, and Sunrun have made, particularly in terms of their lease and PPA products, is something that has effectively democratized residential scale solar. They have come up with a mechanism for getting units on people's roofs where previously there was a major hurdle in terms of the capital cost, and also in terms of things like monetizing the tax credits. That Federal ITC was not something that maybe as many of these constituents would have been able to use, previously. And these new models helped to address that need for monetization in a pretty clean manner.

One thing, though, that I do like to highlight here is that, as I said, there's a surprisingly small number of players driving this forward. There is quite a dominant presence now by three players, and that raises some questions about just exactly how competitive this market is. One thing to bear in mind at this point is the role of this market in, for example, monetizing the tax credit. Developing a product to monetize the ITC based on individual residential systems ultimately requires you to be able to develop a portfolio of thousands of projects before you can go to the tax equity market. You really need maybe 50, more like a 100 million dollars at least in order for there to be a viable deal in that respect.

And so what we've seen is that even though there's a lot of innovation and some competition in this market, there's actually a hurdle to further competition, even in the residential market, because only a small number of players are

actually able to build a large enough portfolio to be able to go and to monetize that tax credit.

To talk a little bit just about the economics of solar in general, first and foremost, there have been tremendous reductions in the capital costs, and at the utility scale, that has actually been reflected in the PPA pricing. And we're at the point today where in certain markets PPAs are selling for less than \$40 per megawatt hour, perhaps closer to \$30 per megawatt hour now, in certain instances, after subsidies of course.

Very curiously, though, if we step away from this utility dynamic, and we reflect on the residential-scale systems, and we look at pricing, it's quite difficult to get information on this trend, but if we look at the system pricing that has been reported across some of the bigger markets, you do not see the same decline over the past couple of years. In Massachusetts, for example, we've seen almost no drop in the reported price of residential-scale PV systems since 2012 or 2013, even though there have absolutely been significant gains, and they're being reported by installers, in terms of reduced cost of materials, and so on.

Much of this is being driven by the fact that they're utilizing this value pricing model, and I'm going to speak now about why this is so important in terms of the overall nature of their business.

So, this is the story. You find an individual who's paying a certain utility price today, and you offer them some price for a PPA or a lease that leads to some price for PV, typically 15 percent below the incumbent. And then there might be some escalator going forward. The typical escalator is somewhere between two and three percent. And this is the model upon which all of these leases are built. And, of course, associated with that lease is a present value that flows from the linkage back to what the utility rate is. So what these residential installers have been able to do is they have been able to

decouple the price of solar from the cost of solar, and that's quite useful. That has not occurred at the utility scale.

Now, why is decoupling the price from the cost so useful? Well, we're talking about an industry where the main federal subsidy is a tax credit, and in order to calculate your tax credit you need to establish the cost basis for the tax credit. And in a situation where you or I would have bought a system, for example, well, then the invoice price would have represented more or less the cost basis. But whether you're leasing a system or you're selling a PPA, for example, things become a little bit opaque, and there's a question as to exactly how do we establish the cost basis for tax credit? Is it the cost of the bits and pieces we put together, with some reasonable markup for return, or is it something else? Perhaps the net present value of my lease, which is by the way linked to the local utility rate.

As it happens, we see a quite considerable deviation in the subsidy that you can achieve, dependent upon the approach that you take for establishing the cost basis for your system. In a nutshell, if you're able to sell a lease where the value of that lease is greater than about 63 percent of the actual capital cost of the system, then you will establish a cost basis for ITC purposes that will yield you greater than 30 percent effective subsidy. And, as it happens, if you took an unsubsidized cost for a residential system that was about \$3.25 per watt, and you ran it through the cost-based method and you calculated the ITC, you'd find that that system would yield about \$1.25 of net subsidy per watt. By contrast, if you take the exact same system and the exact same lease, but you run it through that different accounting mechanism, the subsidy will be closer to \$1.85. That's quite a significant increase, 50 percent almost, in terms of the total subsidy that you're able to yield, without doing anything different at all, really.

One of the most important reasons why that subsidy becomes really important for these

business models, particularly in terms of supporting their growth, is that leasing rooftop solar systems is a terrible business. Basically, if you look at the asymmetry that this business places on your balance sheet, you recognize very quickly why it's a terrible business. You're investing a lot of capital up front, and you have to wait 30 years, 25 years, certainly, to see that paid back. So, in this kind of contemporary business model, with all of these leases, where the real cash flow comes from is the monetization of the ITC.

Just to kind of reflect on some of these numbers, if we took Solar City's Q1 2016 investment plan, at that point, investment was somewhere between 650 and 750 million dollars. Their portfolio was yielding 17 million dollars of free cash flow from that activity. So, that's not a great business, right? And you need to step back, and you need to think about other mechanisms for yielding cash to keep that growing, along with going to the capital markets, obviously, and that's why this mechanism has been so important.

Now, a few things about this. This whole concept of the lease, and this value amplification which is possible, that works really well in states where you can sell more expensive leases. But for these businesses to continue growing, they're going to have to expand into other markets, markets where utility rates are lower, and so on. And what we're seeing is that, within this market today, the players in that space recognize the issue themselves already. They see that this mechanism with the ITC is no longer going to be able to support their growth needs, and they're transitioning away to other mechanisms in terms of moving this kind of asset off balance sheet and looking to support their growth.

That movement towards asset back securitization is very simply an analog to mortgage securities, and I think this is a very interesting next step for the sector. They're also moving towards increased financing—loans, and

so on. I think one thing that's interesting about this asset-backed model is that there's no asset to back up the contract. And I'm not trying to be entirely flippant here. The only asset that you have is the good credit of your customer, because there's nothing to recover from the rooftop. A solar system that's installed today is immediately obsolete, because tomorrow is going to be that little bit more efficient or that little bit lower cost. So we'll have to see how this plays out. There have been six of these offerings at least. It's still a small market. But, as I said, I think it's reflective of how that sector had kind of been innovating their way through their nascency and looking to develop a more sustainable model.

Just some final comments, stepping all the way back to the whole issue about what the subsidies are for in the first place. The ITC, I believe, is very flawed, in the solar sense, because we have this asymmetry in the costs of small-scale systems relative to large-scale systems, which means that in terms of the output, in terms of solar megawatt hours, utility-scale facilities are much, much more efficient. And, certainly, twice as efficient from a taxpayer dollar perspective. And when you include this amplification of the subsidy with this value pricing mechanism, maybe three times more efficient. And so I think we have to look at this kind of mechanism, learn from it, and who knows how things are going to evolve going forward, but I think that we have to try to avoid some of the pitfalls that we have seen emerging from this particular mechanism, for this particular technology, over the past few years.

Question: Is the tax advantage, the ITC for leasing versus selling the facilities, is that something that was written into the tax code when the ITC was adopted, or is that something that has occurred because of the IRS is allowed, I guess, a greater value proposition for the leasing arrangements?

Speaker 4: That has, I think, emerged simply because very innovative accountants at these developers have seen that this is an opportunity and have explored that space successfully. I should add, by the way, that there's an interesting issue here between the IRS and the Treasury. So, people at the Treasury are looking into this valuation issue at the moment, because they were involved on the cash grant, obviously, and there is some litigation ongoing with respect to cash grants that were offered based on some of these mechanisms. But the IRS does not delve into this topic tremendously.

General Discussion

Question 1: There's a series of questions that come to me in terms of what the subsidies picture should mean. And the question I have is, how should we respond to that? And I have four alternatives, and I just want to get the panel's view on these. The first one I call the "throw up your hands" solution. So, I look at Speaker 1's list of subsidies. Subsidies are everywhere. You could respond, "It's tough. Get over it." How should we, particularly people like myself who worry about market design and the health of these markets, how should we respond? And the end view in this first option is "do nothing." It's too hard.

A second way you can imagine responding would be to say, "There are elements of the design of these subsidies in the markets which you could try to alter so as to do the same things, but do it in a different way, so that it was less damaging to the markets." A good example would be the production tax credit for wind. If the production tax credit was a credit for offering the wind as opposed to dispatching the wind, then the marginal offer would be zero dollars, not minus \$23, per megawatt hour, then you wouldn't get all the disruptions that happen. And so you'd have the incentive to have a lot of wind, but you wouldn't have the incentive to distort the operations to the rest of the market. So there are things like that you could imagine

fixing, and I have a short list of such things. So, that's the "adapt markets" approach.

There's a third policy, which I will name after Speaker 2 on this morning's panel. So this is the policy where you say, "This is completely unfair, and our job in market design is to counteract the effect of the subsidies to make sure that they don't hurt anybody else," and we go to an alternative world in which we get prices and markets and so forth that are efficient according to some standard, and we've undone the effect of these subsidies. And you can imagine doing that. There are ways to do that.

And then the fourth approach is "double down." So, if you've got your subsidy, I'm going to get my subsidy, and I'm going to make sure we get subsidies for everybody to counteract the effect, but I do it through the subsidy mechanism, and this is where Joe Bowring's statement in the latest Market Monitoring Report that subsidies are contagious comes to mind. If somebody wants one, then everybody else wants it, and should we be doing that? How should we think about this? What is the policy response? Should we just throw up our hands? Should we try to modify things to make the subsidies less damaging, but working as well? Should we try to counteract them? Or should we all get on the subsidy train?

Respondent 1: I think I will choose option two, at least as an opening point. We have modified designs of various policies, whether it's tax incentives, or whether it's some of the property incentives that I talked about earlier. We don't always do it for the right reasons, and we don't always do it properly, but it allows us to play around with different things. If you think about the Energy Policy Act of 2005, at that point we were worried about running out of natural gas, so we created Federal siting authority for LNG terminals. There were going to be import terminals so we could import lots of natural gas, which, of course, two years later, we realized we did not need to do. But now we have that

legislation, right, that was passed for one reason, and now it's being used, potentially, for export terminals, right? And those are getting through much more quickly (even though it may not be quick enough for a lot of people) than they would have been if we didn't have that change in policy to create more clear Federal siting authority there.

So I think we can improve on certain areas. In the morning session there was talk about how it's not all doom and gloom. The electric industry is moving in the right direction. We still have a lot of problems, many of which we talked about on this panel, with some of these designs, but some of these policies have resulted in good things happening. They've created other bad things that we might not have anticipated. So I guess I'm going to stick with option two for the moment.

Respondent 2: I think the first thing that needs to be done is to inform people about just how poorly these subsidy approaches are working, because if people think that we're making progress with these things, then we're going to continue to have the kind of distortions and ineffective and expensive outcomes that we've seen. So I think we have to dispel these illusions that these things are working. When people think that the subsidies are good proxy for putting a charge on CO2 emissions, they're wrong, because these subsidies are picking winners, and you'd get an enormously different result if we had put a price on carbon than with these selected technologies subsidies. So you can expose the problems here and bring people around to the idea that this is so complicated, and the only way to get to where we need to go is to put a price on CO2 emissions. That's the best of all possible worlds. And, short of that, I think we end up in this messy competition for offsetting accommodations, because we created a big mess for ourselves.

Respondent 3: I'm inclined to choose option one, actually, but only in the context of the

complexity that I've seen around the rooftop solar story, in particular. Take your hometown, Belmont, for example. A colleague, Jake Covey, was involved in trying to assess how that town's municipal system ought to better compensate for rooftop solar, and it just descended into a kind of bitter rivalry amongst the townsfolk. For some of these technologies, particularly at the distributed level, the need for education, as you said, Respondent 2, is really, really profound.

And I think we have to begin to try and move in that direction. And there's still going to be pushback. But I think the practical path forward is at least to start with your second option, and I think there needs to be some alignment with respect to what exactly is the purpose of these subsidies. I think, in particular, looking at that solar versus wind story, obviously, the PTC has caused problems, but in the solar instance we don't even incent what we want, right? The ITC incentive for building solar plants doesn't tell you anything about actually operating those solar plants. And then it also offers three times the subsidy for a system (distributed solar) that produces exactly the same product as utility-scale solar, typically in a less efficient manner, actually, because your distributed units are not as well-aligned with many of the technical needs that we'd like to address. And, furthermore, you might also have issues on the distribution system to contend with. So I think there needs to be some stepping back, looking at the fundamental question about what we want from these subsidies, and then, at least, making sure that they do a reasonably good job at supporting that objective.

Respondent 4: I would answer this by saying I would offer a hybrid of number one and number two, and I would rename it, "an opportunity for a clean slate." Federal tax reform might provide that opportunity for a clean slate, where we could strip out all subsidies and then decide, are there things that should be added back in, and what should those things be? And it could be that it's nothing, or it could be there are some

market failures that need correction. If we decide, collectively, that there's something that needs to be done, or there are some incentives that need to be created, that's when you could look at changing subsidy design, and I think a good example of changing subsidy design to accommodate what's going out in markets is this Section 1603 grant in lieu of tax credit program. When tax equity markets were weak, this was an innovation intended to address that.

However, that said, when you're looking at using the tax code, the tax code can be a very blunt instrument. There's a lot of nuance here. We're talking about how the investment credits for solar create different amounts of incentive for different types of facilities. It would be challenging to then design a differentiating solar investment tax credit based the type of facility. There are complaints already about complexity in the tax code, and then you start doing things like that, and that's introducing and layering more complexity, and you're not very likely to get it right.

Moderator: So, I'm going to take a little bit of moderator's prerogative here because now people are saying, "Well, obviously, the PTC is having distorting effects," so, lest you think there are no counter argument, let me address the earlier comment about negative prices in ERCOT. Speaker 3 was talking about the problem of negative prices. It's zero percent of the hours in 2016 in ERCOT, for the aggregate hub. It gets up to 1.5 percent if you're looking at the North hub, but that's where the generation is. That's not where the people are, or the other power plants. So, are we really that concerned about one percent of the hours for a tax credit that's already been phased out in law? Moreover, gas prices still set the price just about all the time. Sometimes coal sets the price, but not wind. There's a bunch of RTO people in here. How often does wind set the price in your RTO? Anybody seen it? OK. Yeah, so, you know, maybe it's happened. And of those negative prices, it's almost never below \$20 or

to \$23, which is what you think it is. It's almost always in the single digits--like zero dollars to five dollars negative.

So it's not wind PTCs actually setting the price. It's infra-marginal supply coming in there. How many economists would be surprised that adding supply to a market reduces prices? Adding supply to a market does lower prices, guys. That's OK. Policy makers are choosing to add certain supplies to the market, and sometimes that lowers prices, so that's not a distortion unless you think there is no externality out there to be addressed. So that's not it.

Moreover, to allege that it's the PTC causing the nuclear plant closures, when the companies themselves say its gas prices in their financial filings...that's a contradiction there. It is gas prices. Look, flat load, low gas prices, they hurt everybody, OK? And nuclear plants are clearly facing that problem.

So, if we could stipulate that there are some incentives that are designed better than others, then, yes, let's have the broader conversation and answer the four questions. I put myself in the nothing, the camp that says that the wholesale power markets are residual markets in states, and utilities make choices. You may not like the choices, and you can argue with the state, and certainly we do, about some of these choices, but once you're in the wholesale market, supply and demand is what it is out there, and they should be efficiently trading among parties in that market.

Respondent 1: One more thing to think about on this topic is whether we're having this conversation in terms of competing and conflicting policies. Is this a federal conversation or a state conversation? Because I think our answers have all been at the federal level, but if we move to the state level, I think we may have different answers to those questions. There are different issues. There are certainly going to be conflicts between the

various states. Is that OK? We've certainly seen that play out with regard to California and some of their policies. There's a unique set of circumstances there. Also, is the state restructured or not? We've mostly been assuming restructured states, but these questions play out differently, whether we're talking about nuclear, whether we're talking about wind, depending on the design at the state level, too.

Respondent 2: On the point about the percentage of time that you have negative prices, negative prices are very extreme example of the price distortion that's introduced when you put so many intermittent renewables into the mix that you get this serious mismatch between demand and supply. I tried to use a concrete example with real data from ERCOT to show you that we've got price suppression. That doesn't necessarily mean you get to negative prices, but prices are substantially lower across all the hours in ERCOT, because of the subsidized introduction of wind. Now, of course, if you mandate additional supply, all else equal you'll lower prices. That's not the same as lowering cost. And we have to remember, a subsidy doesn't lower the cost. It shifts the cost from a power bill over to a tax expenditure. So, when we mandate and subsidize renewables, we are adding more expensive supply than would be the case if you didn't have those policies. We have to pay for those subsidies, and the remaining generation is now produced less efficiently. And when you shift the cost away from a power bill, we're giving consumers a distorted price signal as well, and you're going to get less efficiency investment because of the effect of the subsidy.

And with regard to the nuclear filings, if you read what people have said, they also tell about the distortions in the power markets. And if you think these distorted markets are giving us a valid market test, and if you think the problem is really low natural gas prices, look at the market results for competitive natural gas-fired generators. The past year, they lost over 40 percent of their market valuations. They are not

winning with their competitive advantage of low gas prices. They are all suffering price suppression in the marketplace.

Moderator: Low prices hurt every supplier.

Question 2: There are so many different ways to take this. On the residual market, this is always something that I struggle with. How much of a residual market do you have to have, before it just goes away? So, 10 percent, all right. You've still got 90 percent in the wholesale market. 20 percent, you've still got 80 percent. When you get to 50, 60, 70 percent reserved to specific technologies, I don't know that you have a market left anymore. And certainly I think ERCOT is seeing that. You just can't have 30 percent of the market be wind and expect to have prices that mean anything. But that's actually not my question. My question --

Respondent 1: Actually before you go on, ERCOT is not 30 percent renewables right now. It's in the teens. And we've got places like California and Hawaii where people are mandating 50 percent or 100 percent renewables. It is hard to imagine, if you've got, right now, 12 percent of your supply coming from wind, and in some hours it's 50 percent, and if you go from 12% to 20%, you've got days when you've got enormous need to curtail, and we're going to see it this spring in California, which is in a similar situation. Wind and solar make up about mid-teens of their generation, and they're going to have enormous curtailments because of this mismatch, this distortion that's been created.

Questioner: So, the question I actually have is slightly different, slightly more forward-looking and independent of the market, but, Speaker 3, your graph makes me think that we need to go directly from coal to clean without the intermediate coal to gas step. And that kind of resonated with me, because when I look and think about building new gas today, a new gas combined cycle's going to have a 30, 40-year

lifetime. And forget 2030. Somebody earlier made a point about how we're going to meet our 2030 CPP targets. That is so yesterday. That's coal to gas, which you can get to really easily. The challenge is how do you get beyond the coal to gas switching, and if what we do is simply build another generation of combined cycles, which I think is where any kind of reasonable carbon tax or sort of short term policy prescription is going to take us, then those assets become the next generation of stranded assets when they are no longer carbon viable in that 2040 timeframe. Do you have any thoughts on that?

Respondent 1: Yes. I think that to answer the earlier question about how we should respond, I think that the biggest problem that we've got is that there are too many people that think they know what the answer is, which is why they pick things to subsidize and mandate percentages and so forth, and if you put a price on CO2 emissions, I think you'd be very surprised at what the actual least-cost pathway is to carbon reductions. Because I've done this analysis for the United States, and it ends up that the answer is, you don't eliminate all fossil fuel use. To get to the kind of two degree targets that we're talking about, renewables are part of the solution, but they're not the majority generation as you get to your goals.

One of the biggest things you can do here is to confront people with the actual cost of these CO2 emissions. Consumer responses to higher prices are far more effective than rate-payer funded efficiency programs. So, the answer is actually quite different, and the whole argument for a carbon price, one of the most compelling things about it is, we don't have to agree on what the least-cost solution is. If you put a price on carbon, the market will move us to that.

Question 3: I find this conversation fascinating for a couple of reasons. One is, you all still assume that climate change matters, which is an interesting assumption at this point. But also,

what I think we're facing at this point is a very different kind of subsidy than you've been talking about. You've been talking about federal policy, which has been company neutral and somewhat location neutral. What we're seeing now with the nuclear, is that it's very company specific. We're only talking three, four companies. There's no competition driving it.

So maybe we don't like a wind subsidy, but at least there's a policy. There was the ability for everyone to compete for it. We're dealing with a very different kind of animal here. It's to keep jobs. It's to keep a tax base, and it's to favor very particular small companies, where nobody can come in and compete. And the question is, if this is going to be an ongoing stage that we're in (and I hate to do this with Bill Hogan sitting here), maybe LMP is not the ideal way to continue this market. Because LMP doesn't reward these investments that are 20 and 30 year investments, right? At this point, with an LMP world, if you're a better generator, you come in the next day and you kick somebody else out, because it's efficient, right? And so who would make a 20, 30-year investment with technology changing the way it is?

So I'm asking you to step back and think about how, in light of all this, the world we're in is so different than the one you're talking about. Would any of your responses to the earlier question change with this in mind?

Respondent 1: I think you raise a very interesting point. This is a very knotty ongoing problem, so where are we likely to head? My fear is that you can see where we're heading on this, which is that these distortions in the marketplace are serious, and they're getting worse. The response is ad hoc, so when somebody looks at the Kewaunee Nuclear Plant, for example, and they say, "Geez, we could keep this thing running for 55 year. The market's only giving it 40. It's a perfectly fine nuclear plant, we're going to close it, and now we're going to have to build CTs to replace its capacity. It's

uneconomic." So you go and you get an ad hoc arrangement to prevent something that you know is uneconomic. So, there, you've got a solid rationale for the kind of New York, Illinois kind of payment schemes, because we know prematurely closing these nuclear plants is a distorted outcome, and it makes sense to keep them running.

Where do we end up with all this? We probably end up re-regulating the electricity industry through widespread contracting. And that's where we end up on all this, because the other thing that happens here is we put so much of this renewable generation in, and if you want the market to solve your problem...people embraced the market because prices were high and varied. And so that's what triggered deregulation. It wasn't an ideological epiphany for people. That markets were superior to regulation. They said, "Look, prices are really all over the place. I want choice. I want competition." People thought that if we moved to markets that were driven by customer demand, the markets would force suppliers to efficient and low-cost supply. The problem that we've got now is that we've got, instead of a demand-driven marketplace, a supply-driven marketplace. We've got so many mandates on the renewables that now people are saying, "Well, let's use the market to give people a price signal to change when their toaster is going to toast their toast." And that doesn't make any sense. People are not going to support markets that are trying to use price to make a supply-driven solution and reshape when they get to consume their electricity. So I think this is going to erode the support for the marketplace and lead us to this situation where substitution of regulated contracts for the market will be, increasingly, the reality that we face going forward, unfortunately.

Moderator: Anybody else want to comment? The question is about whether it is different to have a market-based incentive versus a company and plant-specific incentive. Is that latter thing a

new animal that's categorically different, or just one more on a long line of incentives?

Respondent 2: To me, it seems sort of similar. Here we're talking about nuclear facilities that in particular states, with those states' markets, that they've designed, they don't work anymore in conjunction with the production tax credit and everything else. So it doesn't work anymore, so we have a backdoor fix, and it really is kind of a backdoor reregulation.

Question: Are you saying it doesn't work? The RTO is saying these units can retire and there will be no reliability problem. What is it that's not working?

Moderator: It's more costly.

Respondent 2: Well, but then there's the other problem of, if you're taking all of this carbon-free electricity off, there are concerns about that.

So, the question is, what do you do about it? At least a couple of states have tried to do a short-term fix. Is that bad? For some in the industry, sure it is. For others, not so much. Overall, we're trying to figure out whether this is the best choice, going forward. It's not ideal.

Moderator: Well, there are different views, apparently, on whether these are definitely economic. Was there any reason not to support an open bidding process? If you have a half billion dollars to spend, put it out for bid. Would you object if you think it's the low-cost solution? Then everybody should win, right?

Respondent 1: Bidding for what?

Moderator: For that carbon-free electricity that they fear losing.

Respondent 1: Yes, I think that any approach that is technology neutral is a better approach than these technology specific picking-winner subsidies. So, essentially, if you put a charge on

CO2 in the absence of all these subsidies, you get the result that you're after.

Question: Right, but that's not happening. So, the question is what do we do in the meantime?

Respondent 1: Well, it is and it isn't. I mean, it's happening in some places around the world. In western Canada, they've put on a carbon charge. And you have to think, is there a window of opportunity to try to do this? If the current Trump administration wants to increase military spending, increase infrastructure spending, cut the tax rates, and not move the deficit up, maybe those old guard Republicans that put the proposal out about a month and a half ago that a carbon tax would be appropriate, maybe there's a window of opportunity here such that the politics can come together and get us partway down this road. Otherwise, this is too complicated, and we've got too much evidence that these command and control approaches simply aren't working.

Question 4: I wanted to ask about ZECs and the nuclear subsidy programs, because I do think they really changed the conversation. And they weren't addressed too heavily, at least in the talks. I agree with the statement that's been made that this is kind of a supply-driven crisis. And, usually, when you have too much supply in a market, what you see is consolidation, bankruptcy sometimes, retirement of assets, right? We're seeing that in coal mining right now. A colleague of mine, Frank Wolak, likes to say that what we really have is a thermal retirement problem in the power sector, and the challenge that occurs whenever a sector is in crisis (you saw this in the banking sector, right) of allocating losses. And what we're seeing is a pushback against allocation of losses in a particular way to shrink the supply.

Respondent 1: There is a perception that the problem is low gas prices, not market distortions, which is why I think it's important to appreciate that the testable hypotheses there

is, are there winning competitive gas-fired suppliers out there? And the answer is, no. It's not that you've got gas guys winning and driving these other guys into bankruptcy. Last week I was over in Germany. They went on this enormous subsidized renewables kick. They cratered the market prices and drove their retail electricity prices through the roof. Their CO2 emissions in the power sector have gone up, and the existing players have gone bankrupt and have had to reorganize by breaking themselves up.

Question 5: I just want to follow up on some of the things that were said earlier about the subsidies. Part of the problem with respect to the cost is not only that we end up paying for things such as the nuclear subsidies, but that a classical moral hazard problem emerges. Once the feeding trough is there, you want to get your bid in, and so some of what we see across the region is that the hard part now is to scratch our heads and ask ourselves, "Well, which of these resources really need the additional subsidy to remain in operation and which don't?" And out of fear that they retire, we end up paying all of them, and hence the costs go up. The next risk in this is that, with these rules, integration faces a world where the LMP's and the capacity market prices don't support new entry, but we need more fast-ramping capacity, whether it be CTs, or whether it be the newer CCs with the fast ramping capability.

And so the question is going to be, "What do we do to get that match, if the ancillary service markets aren't sufficient in combination with the energy markets and capacity markets?" And there's a good chance that evolves.

But I wanted to go back to something that the moderator said about how we got here, and I think you phrased it as, "policy makers want to put supply in the market." And it seems to me that's exactly the problem. I understand completely why policy makers want to establish goals and targets, want to establish the climate

changes a problem, and want to establish that we need to meet certain targets. But the problem emerges when the policy makers with short time frames, two, maybe six year terms, start to want to make decisions where their impact is seen now.

In Massachusetts, we have our new Governor Baker, who wants to pass a bill for offshore wind, because Rhode Island got theirs. And what drives things like that is policy makers wanting to do things. And I've talked with people from New England. They say, "Well, we can't tie the legislature's hands." And that's true, but you can send them the message that what you're doing is causing real problems. Maybe not for you, but for the state and for the next round of people. And that's the thing that I feel like I need to push back on. A lot of this is being driven at the state level. We make this choice between letting the market do it. In New England, we're not even relying on RPS. We're relying upon procurements, going out and buying exactly what we want. We have RGGI, and we tout it, but the reality is, we don't rely on it at all. We just rely on it as a tax to fund certain programs. But we don't want policy makers making supply decisions. That's for the market to do.

Respondent 1: We've been speaking about the market, and so on, but so much of this is just purely driven at that state level by decisions that are leading to tremendously suboptimal outcomes. In Massachusetts, for example, support for solar increases as the systems get smaller. That's not a helpful approach in terms of driving towards some of the state's goals around decarbonization, and so on. But you have other agendas, and I think that complicates this entire matter. And, frankly, it doesn't seem like there are a lot of avenues, in the short run, for transitioning out of that other than, as was said previously, beginning to make clearer how these decisions are coming together to actually act against, in many instances, the stated objectives of these policy makers, and so on.

Respondent 2: This goes back to the point that was made about these subsidies being contagious. The problem is, we've locked in this production tax credit for more than a decade, going forward. And so then people need subsidies to counteract the effects, and so forth, and this week in the *Energy Daily* there was a story there where California gas-fired flexible load-following generators are now making the case that they need additional payments or else they're not going to be able to keep providing the backup and fill in for the intermittent renewables, so we're on this slippery slope of everybody needing some kind of a deal to counteract all these distortions, and we are sliding down that pathway, it seems.

Moderator: I feel like we're lacking in economic policy principle here. Joe Aldy from the Harvard Kennedy School testified yesterday. So, he laid out four or five policy principles. I wish I had them, but it was something about addressing the externality. Focusing on that. So, clearly, for that, the first best approach would be a carbon price. I think Speaker 3 and I agree on that. Other principles were minimize distortion, something like that, and make it competitive. And it seems like the extreme opposite of that is if you actually pick the power plant that gets a subsidy, that's pretty extreme. And if you pick the technology, well, at least any company making that can get the subsidy, and that's much more competitive, and therefore lower cost. But if you don't pick the technology, as you're advocating, and pick the externality alone, and stop there, then all sorts of other solutions that may be cheaper than the chosen technology could come in. And does anybody here argue with that? That that's what we should strive for, and absent that, we're kind of in the world of second best? Is this a second best, or a tenth best outcome that we have?

Question 6: Some of the panelists were making your remarks about reregulating with a whole system of bilateral contracts. One of the longer-term outcomes that seems most likely to me is

that we will have this really expensive mass of all of these contracts, and it won't accomplish what people were thinking it would accomplish, and people will look around and say, "We need markets." [LAUGHTER] And they'll go all the way back to the same thing. Bill won't be around to help them. He'll be sitting in his house in Cape Cod, and we'll just go remake the wheel again. We will have lost a lot of the intellectual capital that created this stuff to begin with. And we'll have just replayed the PURPA nightmare again on a much bigger scale. Likely, or not?

Respondent 1: There is always a possibility, when you say, "Here's what I think is going to happen," that people interpret you as being in favor of it. So, I'm not in favor of a contract world. But, yes, it seems that we have a very unfortunate coincidence. The experience with regulation convinced people that it was inefficient, and we had prices that were too high and too varied, and we went to the market, back in the mid to late 90's. Unfortunately, that coincided with the kind of growing awareness that climate change, global warming, is a real problem. And so we had this convergence of a push to the marketplace and a push to greater and greater environmental intervention, and the two of them have intersected to create a really bad mix of market forces and regulatory edicts that's created a pretty ugly result.

Respondent 2: Well, just to add to that, I agree with everything you just said, but not only do we have this sort of unfortunate convergence of markets and climate, but not everybody cares about climate. Not every state cares, and wants to take into account carbon or do a carbon tax, and we have flip flopping at the federal level, too. So that's why these issues are so difficult, because we have even less consensus about what has to happen now than we did before, when there was more a focus on lowering prices. We might have debates over the best way to get there, then, but our, we don't even have an agreement on the premise right now in terms of from state to state and then on a national level.

Question 7: If you look at what's happening in the states, let's be clear. This is not being done for carbon reasons. If this were being done for carbon reasons, you wouldn't be selecting only certain plants, and you also wouldn't be avoiding or ignoring the contribution that other fuel sources can make.

In New York, even a retail company like Direct or NRG or anybody else who is providing a 100 percent renewable retail product still has to pay for the ZEC. And we're also now going beyond plants that are closing or have threatened to close or have actually put retirement notices in; we now have plants across the entire PJM footprint saying they want this subsidy, not because it's new technology and needs to be entered into the marketplace, and not because the plant's about to close, but just because they're not recovering their cost of capital. So I think that just proves the point about subsidies being contagious.

Here's the question: everybody seems to agree that we're headed in the wrong direction. And if contracts are where we're going to go, who's going to make this decision and make it happen? Because right now, states can willy nilly pick and choose subsidies and then leave everybody else out in the cold. The PJM report issued just today showed resources are needed for reliability, too. So, if FERC's not going to do it and provide the compensation, and the states can selectively give some people subsidies and not everybody, and we need to get to, unfortunately, the contract stage, who's going to make that happen? And what remedy do people in the marketplace have who are left out of the party, who are still needed, when everybody else is getting special treatment? It's not 10 and 20 percent. In New England we're almost going to have over half the market decided by nonmarket mechanisms in a few years. That's the slow train wreck that's about to happen. So, if anybody's got a solution I'll buy them an extra drink at the reception. [LAUGHTER]

Respondent 1: You do have an interesting hypothetical. What if, with the new appointments at FERC, the determination was made that it's not just and reasonable to intervene in a market and mandate 50 percent renewables--that the distortion in the marketplace is going to be so great that it can't be tolerated. You could envision some kind of striking reversal of current trends, but we'd have to wait and see.

Question 8: I want to take things back a little bit to the conversation this morning and to this idea of the orchestra conductor, because I think it fits very well with this conversation, as well. It goes to the idea that the load serving entity, which is what we were talking about this morning, has to plan a portfolio, design and put together a group of resources that work best together to provide safe, reliable, affordable power. And in a world of contracts, who decides who gets the money or doesn't would be that load serving entity that's putting together the portfolio. In the old world we always did that under the direction of the states, telling us that there were certain things they liked and certain things that they didn't. Even the nonregulated cooperatives still were facing some of that direction from the states. So, having the states involved in resource decisions, having utilities in states making choices amongst resources, isn't a new and a scary thing necessarily.

There are, however, a lot of really bad decisions being made about how to drive those decisions. So the question is, from the perspective of this conversation, how do we decide between those dollars that are being spent to reflect the preference of the wholesale customer in a market that can't differentiate (going back to the orchestra metaphor) between Justin Bieber and Beethoven? If the customer wants Beethoven and the market's delivering Justin Bieber, the customer is going to be providing money outside of the market for the things that they want. How do we differentiate between that which is proper

economic behavior and the subsidies that are being decried? What are the principled economic rules that would distinguish between those?

Moderator: What say you? Is there any fundamental difference between load serving entities choosing the power they want to buy and a state choosing to have a high percentage of renewables?

Respondent 1: Well, I think there are a couple of things that come into play here. One is that a load serving entities' decisions affect the broader marketplace. Look at California. Its renewable requirements have got ripple effects all throughout the west. So this isn't a case of individual players being able to all do their own thing, and it all coordinates properly. And if I understand your original point, I don't believe it's true that if people want renewables, then we're giving them renewables, and that's what they want, so if these are the distortions you live with, well, that's part of the deal. Because you look at New England, and it makes sense that people wanted renewables to reduce CO2 emissions. They got the renewables, they depressed the price, they closed down nuclear units, and CO2 went up, and that's what they want? We've got some really perverse results happening here, and I don't think this is what people want, and I don't think it was the intended outcome, as well.

Moderator: To the questioner, are you saying you're putting yourself the first, "do nothing" bucket? You're saying, focus on who's responsible for resource adequacy and procurement, and, if I understand you right, you're saying that's very compatible with a bid-based locational spot energy market. So you should do that, and that's fine, not incompatible.

Questioner: Right. I don't want to suggest that I'm a big fan of PTCs or ZECs or some of the other incentives that are out there to drive investment. But I do think there is a role for

states and utilities to make decisions about the kinds of resources they want, even if those aren't the resources that the market happens to be delivering. So the question is, how do we bring those two ideas together? I think I do have a solution, which is an LSE-based solution. It's one that looks at competition as open access, as opposed to centralized markets.

Moderator: Well and it helps with the missing money problem that there is presumably a capacity value in those long-term contracts.

Questioner: One would think. But then, given that we are in an in-between situation, all we're left with right now is Joe Kelleher's definition last summer, when he said there are ugly subsidies and not ugly. So, how do we allow the customers to make decisions? How do we allow states to have influence, with a somewhat more principled differentiation between ugly and not ugly in terms of how they go about it?

Question 9: Speaker 3, I find myself, after your presentation, thinking that there's actually more going on here than just the PTC and ITC for wind. If I look at your Texas slide with the supply curve and the price impacts, it doesn't take much of a change in the gas price to have a much larger impact on price formation than what you're talking about, with the prevalence of new gas entry, and notwithstanding your claim that the gas units are not making money. They may not be making the money they want to, but we're still seeing new entry. To me, as a revealed preference argument, that says that they're doing OK.

So, the question becomes, where do we go from here? What do we do? What are the options? And I think there's actually one option that's door number five that we haven't really talked about. Some of our markets have a well-functioning forward capacity market. The forward capacity market's designed to make up for the so-called missing money, but the thing is, about renewables, renewables have a very low

capacity value because of their intermittent nature.

Moderator: They are what they are. 20 percent, 15, take it.

Questioner: So, the issue of them affecting the capacity market is not so great, but they do affect the energy market. I don't think there's any issue around that, and I agree completely, we need to price the externality, but why not a capacity market? And I think it's different from an ORDC-type model in the following sense. You never know when those shortage events are going to come. But a capacity market reduces the value of the real option to wait on the invest or go forward decision. And so we're going to see very different outcomes from that. And, because it can recover some of the so-called missing money, and because renewables don't have that effect on the capacity market in the way that, say, some other fossil resources would have, or steam resources like nuclear, doesn't that help kind of get us over the hump, at least for the PTC/ITC renewables? I mean, we're seeing issues with nuclear and some of these markets.

I would also note that there are no retirements in Texas in one of the slides that you put up. That retirement's elsewhere. Could it simply be that the units in Texas are that much more efficient than nuclear units and the ones that are retiring? After all, there are approximately 100 operational nuclear units in the United States. They can't all be above average, in the words of Garrison Keillor.

Respondent 1: A number of years ago we looked at the ways that we see people trying to address this missing money problem. And one of them was that you rely on behavioral economics. Even if you've got compelling historical evidence that merchant gas-fired generation is unprofitable, you're always going to have a tail of optimists, what people call the winners curse. And so, despite evidence to the contrary, you're

going to find people that continue to invest, based upon their bias to optimism. So, when you have a kind of bidding under uncertainty or investment under uncertainty, the market's an efficient way to tease out the optimist. And what you find, then, is that the people that invest are typically not successful. If you look at the transaction prices of natural gas-fired development across the United States, the second owners are buying stuff at about 60 cents on the dollar. And if you look at the key natural gas competitive generators, NRG, Calpine, Dynegy...look back over the past 10 years. They all went through one bankruptcy reorganization. If you look at when they had their stock price highs, it's typically shortly after they emerge from bankruptcy, and then they start to invest again, and they start to destroy their valuation all over again.

So I don't think we've got compelling evidence that we've got a healthy investment climate for power supply. But, as I said, I'm not worried so much about reliability, because I think that the missing money problem has got two parts. One is inherent, which is what the ORDC and the capacity markets fix. So I'm not worried that you're not going to have enough revenue to build peakers to give you the capacity you need. What I'm worried about is that you've got this imposed problem, where we've created missing money in market cash flows. We're going to build too many CTs. We're going to have a very inefficient generation mix. It will be reliable, but it will be inefficient, and that's my biggest worry. That that's the path that we're on, and the penalty that we're paying for these subsidies.

Respondent 2: We have different potential answers to these problems depending on different policy choices, but also different technology developments. We were able to do a lot with wind, because you could build wind fairly quickly, and the same with gas. You can build that. I think part of the challenge with the pushback on the nuclear is, yes, it's to protect what we have already, because we can't actually

build new, we might be able to build new different things, but we can't build new nuclear. And can the new things that we build substitute for the nuclear retirements? Whether the incentives are to reduce carbon or to save jobs, there at least is now more of a conversation about what role nuclear plants play and what technology substitutes we have for that. So, I think there are different answers, depending on how technology develops, and then also what we decide to do on various policies, whether it's carbon policies or others.

Question 10: I just wanted to re-ask the earlier question about options, but without everybody's favorite answer. If I recall correctly, that was answer number two, which is, "subsidize better and smarter." Let's assume we tried to do that, and I can speak from experience that we as an RTO have tried to do that in New England. We have sung the praises of carbon pricing and then subsequently been dismissed about as quickly as they can dismiss us.

So let's assume that the subsidies that New England is trying to put in place, that the states are trying to put in place, are going to happen. You don't have the option to change them. Do you choose option one, which is do nothing, or do you choose option three, which is try to counteract them, or option four, which is double down--and I'm not quite sure what that implies, but I'll let you all fill in the blanks.

And the more important part of the question is, if you choose option three or option four, what is the purpose that you are, why are you saying, "let's do something?" What are you trying to achieve with this? Because, to me the fundamental inefficiency has already happened. If you're subsidizing something, you've created inefficiency. It's not clear to me that creating another one on top of that makes the world a better place, but that could well happen.

This is sort of the bonus round. If you choose option one, can you tell me how to more quickly

get to the state of the world where we've got the states that are responsible for all contracting for all resources? Thanks.

Respondent 1: I think that we will have these ugly choices. If you've got a situation where you clearly distorted the marketplace, and you're leading to an uneconomic closure of a plant (and I think a lot of these nuclear plants fall into this category), you are probably better off providing the ZEC kind of approach to keep it running, rather than have it closed, because of the context that we're starting off in a distorted marketplace, and we're trying to minimize the unintended consequences of the distortion. But, as we said, this is a slippery slope. You do that for the nukes, and you've got other people coming back to you saying, "Hey, what about me?" And where does it end? It's not a very attractive road, but probably one that will necessarily have to be traveled.

Question 11: Here's the question that no one's asked through the whole debate. Let's assume you're right, that these plants should not close, for all the reasons, whether it's carbon or what have you. Now, here's the key question. Why, then, is the payment to keep them open based on the social cost of carbon, when, normally, when you think of an RMR contract, if there's a decision that the market is not providing something that's needed, the compensation is not some number that's a 50 to 70 percent premium over the market price. It's a cost-based contract, or it's the market price rate. So, if they want to give up their market-based rate authority and go to cost-based, that answers the question of keeping them open. No one's addressed why the compensation is so great as it is, so the distortion is even that much more.

Respondent 1: You're getting into the weeds now. If we agree that it's better to do some kind of compensating action to counteract this distortion we've created, what's the minimum payment that you'd have to do in order to counteract this market distortion that we've

created? That's the follow on to accepting the idea that we've got some serious distortions here.

Question 12: First off, I might just answer the previous question. The reason you don't do cost based is because you'll get sued by EPSA. [LAUGHTER]

Secondly, you can count me in the camp of agreeing that the best way of dealing with this would be to internalize all of the costs. But what does that really mean? It means that our current market is also completely distorted. And I would also say that it's tougher to undistort than it may seem in passing, in part because carbon is not the only thing we care about. And the states are dealing with this when they're making these policies. So, for example, nuclear plants have a risk of catastrophic failure that's very hard to quantify. They also have no waste solution. So to just say that states have to do this ideal economic policy and if they do anything different we will invalidate it, I think, is a very risky way to go. And the idea that the solution is to have the federal government invalidate the states' policy choices and force them into a situation where costs are not internalized seems very strange to me.

I would tend to agree with the questioner that the choice might be kind of between option one and options three and four. And if we're going with three and four, that means we're in a situation where costs are not internalized.

Question 13: Someone asked what we are trying to achieve. What's our objective here? And I would argue that the most important objective is to keep the planet from warming more than two degrees, and if the best estimates are that we need to reduce our carbon emissions by 80 percent by 2050, or whenever it is, we should try and do that in the most efficient way possible. Let the market drive us to that outcome, if it will. I'm not sure a carbon tax is necessarily a free market. It's consistent with a free market,

but I don't think the Freedom Caucus is looking to George Shultz and other granddaddies of the Republican Party for guidance on tax policies. So I'm not all that confident that we're going to see a carbon tax.

And without a carbon tax, how do we achieve those carbon reduction goals without distorting the market or interfering with the market in some fashion, whether it be ZECs, or 10 billion dollars to keep nuclear plants running, or feed-in tariffs that have a premium for renewable energy, or other tools that are market distorting, but arguably necessary to achieve what I would argue is the most important policy objective we have?

Respondent 1: One thing that's important to keep in mind in this debate about carbon emissions reduction is that the production tax credit and the investment tax credit are not efficient vehicles for achieving that goal. That's not the path that you want to take.

With respect to a carbon tax, it's true that you're not going to get it right, in terms of setting the level. You're not going to have an entirely efficient outcome. It's just too hard to figure out what that level should be, but there's the other benefit to having the carbon tax, which is that it raises revenues. And so when you want to raise revenues in order to keep income tax rates lower, or something like that, there's that benefit to a carbon tax. In contrast, if you do something like a feed-in tariff or some sort of other form of subsidy, then you've got to raise revenues elsewhere in the system to finance that subsidy.

Questioner: I'm all for carbon tax, by the way. I just don't think it's realistic, and I think there's got to be a plan B and I'm not sure how that's achieved without a lot of market intervention.

Respondent 1: Well, maybe everyone's assuming that the market is going to save us, and if we design the perfect market then that's going to be our solution. It's certainly a big part of it,

but there's more that needs to happen on some of these other fronts.

Again, putting a lot of money into technology development. You build taller wind turbines, and all of a sudden you can have wind in the Southeast in a way that you can't right now. You expand grids. You figure out a way to get a western grid. Maybe you get rid of some of these barriers to long distance transmission that exist in terms of property issues. I mean, 10 years ago, did we think that we could even support the amount of wind we have in some of the regional grids now without the lights going out? No. We thought it would be impossible. We could never get to five percent. We had all sorts of reliability problems. Well, we've gone way beyond that, and that's because of technology developments and broader grids. And so I think we can expand on that quite a bit, in addition to designing these markets properly. But I don't think that we can rely on the markets to do everything.

Respondent 2: I think if you analyze the least-cost pathway that you would get if you used a carbon emissions charge, it tells you what mix of approaches would make sense. And I think, if you do that, it will tell you, for example, that 50 or 100 percent renewables is not the way to go. So even if you don't use the carbon price as the policy instrument, if you use it as the basis for your analysis, you can get a benchmark of what mix of things would be the most efficient way to go. And then, if you have command and control kind of approaches that try to get to that kind of mix, you'd be better off than not doing the analysis and just assuming the can opener--that we can get to 50 percent renewables, and the batteries will get us there, and so forth.

To the earlier point about nuclear and the cost of a catastrophic accident and so forth, when I put this example together I tried to emphasize that these distortions are preventing investment in inflexible, more efficient resources that would be part of an efficient mix. The example I use is

cogen. Everybody loves cogen. People don't like nuclear, but they love cogen. And if you distort the market, you under invest in cogen. It's inflexible but highly efficient.

So this is really about distortions that are leading to inefficiency, but on the nuclear side, if we do need to get to an 80 percent reduction in carbon emissions from where we are, it gets us in the U.S. down to about 2,400 pounds of CO₂ per person per year in the electricity sector. There are a number of developed world economies that have that kind of an electricity carbon footprint. And so the question is, who are they? Could you follow their example? There are countries like Iceland, but not everybody lives on top of a volcano and has all that geothermal, right? So you can't follow their example, but you do have the example of Ontario and France, which are combining renewables, nuclear, and fossil in proportions that if everybody in the world did what they're doing, the power sector would have done its part to meet the two-degree scenario. So there is some guidance out there.

Questioner: The price of solar in Ontario is very expensive for their customer, right? There's a subsidy there that is designed in balance with other technologies.

Respondent 2: The lesson from Ontario is that they've got the kind of electricity carbon footprint you want. They got there at two or three times what it ought to have cost them.

Respondent 3: I think the cost thing is important, and I think a major barrier to a carbon tax, politically, is recognizing that the customer may have to pay more for electricity. We talked about the average customer this morning having a utility bill of \$100, and the customer just not receiving the price signals, or the signals not being strong enough for them to react, for them to use less electricity, and that's something that we need to address and think about.

Respondent 4: Just one final point, if I may, on this. When we talk about the issue of climate, for example, we're talking multi-decadal timeframes. At no point have we discussed, in this conversation, the profound potential that the real distributed concept can offer in meeting a different paradigm and delivering power through much greater utilization of some of these distributed technologies that are still nascent today, but that, with advances in storage and so on, could actually yield an important added flexibility.

Respondent 2 brings up France. I'm not sure how many of you guys know this, but every house in France has an electric hot water heater in its basement that the operator turns on and off with a simple signal on the wire when they want to keep their nuclear assets running, but they don't have the load. That is a 1970's version of where we could go with that much more flexible system overall.

And so when we were talking about markets here, I think you know there's a tremendous challenge with respect to where the large-scale markets are going today, but I think it's also really important, particularly given the folks in the room, to keep an eye on the question of what can we do by investing into our downstream assets to make them ready. I don't think the technologies or the cost envelopes are where they need to be yet. But they're getting there, and in a decade's time I think this will be quite a different conversation.

Session Three.

EPA Clean Power Plan Redux: What Now?

In the Houston meeting of October 2015, a topic was the final rule setting emission guidelines under the Clean Power Plan. Then, the questions focused on the relative strengths and weaknesses of the proposed rules, as well as the legal vulnerabilities. How should electricity market participants respond in the new world as it would unfold under the CPP? Now the world has changed, in then-unexpected ways. The stay by the Supreme Court was unprecedented, and the election of the new Trump administration could change everything. Some states are going ahead on the original path envisioned under the CPP, others have stopped work, and others still are looking for alternatives. The list of questions and possible futures is as dizzying as it is important. How should electricity market participants and regulators think anew about the tasks and opportunities of addressing the challenges of clean energy? Is all this a fundamental change in direction or a temporary diversion from a long-term policy direction? We return to the same topic, but in a different context. As before, the question is: What now?

Moderator.

Good morning all. So, this morning we brought back our panel to discuss the Clean Power Plan (CPP). The last time we were together to discuss this back in 2015, the Clean Power Plan rule had just been proposed. I don't believe it had even hit the *Federal Register*, because that happened October 23rd of 2015. At that time we discussed the legal viability of the proposed rules and hypothesized about how the states would implement these rules and what impacts the CPP would have, if any, on the power markets.

A lot has or has not changed since that time, depending on how you look at things. In 2016, the Supreme Court stayed the implementation of the Clean Power Plan, and then as recently as this week we know there was an executive order from Mr. Trump related to the EPA reconsidering the Clean Power Plan.

Back in 2015, one of our panelists quoted a famous baseball player, saying, "It ain't over until it's over." And that was very relevant then, and still relevant now.

Speaker 1.

I'm going to talk today about the remaining legal issues in the D.C. Circuit, and just give my perspective on how that will be resolved

I think Berra's quote is true now, and it will be true in four years' time and in eight years' time, until there is certainty about what the federal approach to greenhouse gas emissions is going to be. The statements from Administrator Pruitt suggest that there will not be a replacement for the Clean Power Plan, and that's going to leave a vacuum, and so, if you think through the demise of the plan and the implications of that, there are implications for states, and there are also implications for where the puck is going to be in four years, or eight, as we think about eventually filling that vacuum at the federal level.

Last time, we were talking about the big legal questions that were raised by the creative, innovative approach that EPA had taken to implementing Section 111(d) of the Clean Air Act. There was this dueling statutes issue and that beyond the fence line question. And the elephants in mouse holes question that had been raised by Justice Scalia in earlier cases with respect to greenhouse gases and the Clean Air Act.

However, then this happened. President Trump signed the executive order, and really this formalized something that was quite obvious, given his choice of EPA Administrator. This is

called winning your litigation by other means. EPA has gone into the D.C. Circuit and asked the D.C. Circuit, which is fully briefed on the case, not to rule, and I think it's just totally realistic to expect that they will not.

The Constitution says judicial power shall extend to all cases arising under the laws of the United States. What does that mean? Well, it means that U.S. courts do not give advisory opinions. No principle is more fundamental to the judiciary's role in our system of government than the constitutional limitation of federal court jurisdiction to actual cases or controversies. It's going to be very hard for states and environmental groups to argue that there is an actual case or controversy with respect to the Clean Power Plan, once EPA completes its review and revokes the rule. There will be litigation concerning that revocation, its justification, et cetera, but I think we should not expect a decision in the current case regarding how to interpret Section 111 of the Clean Air Act.

So, what does that mean? Well, there are sort of two groups of states. There are the reluctant states that are the majority right now in our country, and I think what that means for them is what we talked about yesterday. There are the continued impacts of low demand for electricity. I think that's the fundamental driving factor that cannot be ignored. There are low natural gas prices. There are renewable and nuclear subsidies. And all those things imply something not very far from Clean Power Plan compliance for many states by the time the deadlines actually arrive.

There's a slightly different picture in what I'll characterize as the more enthusiastic states, and I'm going to talk briefly about what's going on in those states. In California we have an existing cap and trade program that runs through 2020. The program, like all cap and trade programs ever that regulate greenhouse gas emissions, is currently over-allocated. As a result, the price of

emissions is at the price floor, but, interestingly, the state legislature enacted, last August, a very ambitious 2030 target that essentially implies that California emissions are going to fall 40 percent over 10 years on a statewide basis. They enacted the target, but because of quirks in public finance law in California, the cap and trade itself needs to be reauthorized by a two thirds majority vote. And that process is one that's playing out right now. There's a very active conversation within California government around potential modifications to the market design to enhance cost containment features.

And that, combined with California's penchant for many other types of energy and climate policies, implies continued carbon tax-like behavior. Right now California essentially has a low carbon tax at the reserve auction price, similar to behavior we've seen in RGGI in the past. It's likely that under the enhanced stringency of the cap and trade program after 2020, we might see a flip from the price floor to the price ceiling, but then continued carbon tax-like behavior, moving along the price ceiling instead of the price floor of the market.

In RGGI, there's a debate over how much to cut emissions, but all options imply higher carbon prices, likely as soon as there's clarity about what the target might be, because of the banking provisions. And this characteristic is also true of California. A challenging issue for RGGI, I think, moving forward, is that, unlike California, there's no provision for managing imports of electricity to the system, and you see this issue coming up most notably in the difference of opinion between the PJM states, especially Maryland and the ISO New England states, about how to think about the cap, moving forward, and what to do about leakage.

There are other modestly enthusiastic states. And I think we're likely to see more of these. In the absence of Federal action there's no excuse,

in states that support action on climate change, for not taking action at the state level.

One place where we've seen action this year is in Washington, where Governor Inslee's DEQ finalized the Clean Air Rule. It's currently being challenged, and it's going to be an important test, at the state level, of the ability of state governments to use their existing statutory authority under their state clean air acts to regulate greenhouse gas emissions. This is sort of going to be an interesting case to follow in that respect. Sort of a state-level repeat of what we have been seeing under the Clean Power Plan.

In addition, there's an interesting process in Virginia to look at how to achieve the Clean Power Plan targets using existing statutory authority. We'll see where that goes. It remains to be seen.

The implication for states of the current situation is an increasing difference between what the energy and climate policies of the enthusiastic states and those of the reluctant states look like-- a growing bifurcation.

Turning to implications for ISOs and RTOs, I'm going to focus here on the WECC, where there's been a very active conversation, over the last 18 months or so around regionalization. This was really kicked off by the California ISO's move to create an Energy Imbalance Market (EIM), shown here as the current footprint, and then the planned expansion over the next couple of years. I think it's fair to say that the death of the Clean Power Plan really lowers the odds of WECC regionalization. It lowers them for two reasons. It makes California legislators, who have to pass a law to change CAISO governance, more concerned about greenhouse gas emissions that might be part of a WECC-wide unit commitment market. And it makes the non-California legislators, who have to agree to some sort of governance package and join an RTO, less

willing to go along with "crazy" California when it comes to greenhouse gas emissions.

There's some discussion of an RTO without California. We'll see where that goes. Obviously that has bigger infrastructure implications than everyone joining the CAISO and its infrastructure with a new governance regime.

Interestingly there have been questions raised informally by some of the non-California stakeholders regarding what's called the bid adder--the fact that imports of electricity to California via the EIM face a carbon price. Right now that carbon price is low. If the carbon price rises, some of these participants might feel or have expressed some concerns that it might be unduly discriminatory.

The conversation in California and the WECC really raises a question about whether a carbon market and an electricity market can co-exist when they don't have the same footprint. And we've seen a lot of proposals from RTOs in the context of the Clean Power Plan about how to think about RTO-wide compliance. It's sort of an obvious solution. But we're in a context now where we have to think about these enthusiastic states and less enthusiastic states trying to collaborate on electricity market design, even as they diverge on carbon pricing.

Turning to a new topic, what are the implications for Federal action? Like I said, there's going to be a continued divergence of states that tax brown versus states that subsidize green, or states that both tax and subsidize versus states that only subsidize.

One implication of this is that it's going to complicate the distributional implications of any future price on carbon. That was a hard challenge, both under Waxman-Markey and the Clean Power Plan. And it limited, to some extent, the ambition of the Clean Power Plan, and one point of criticism of the final rule and the allocation of effort under the Clean Power

Plan was the distribution implications. And the more different states get, over time, the harder that problem is going to become when we eventually deal with this issue.

Another implication is that delay is going to shift the focal point of a future negotiation. The more states have meaningful carbon prices in the country, the higher a carbon price will be that will seem like a reasonable outcome to any future negotiation. We're moving from an environment where California has a \$10 carbon price and RGGI has a \$3 to \$5 carbon price to one where California might have a \$50 carbon price by the time this is resolved, and RGGI might have a \$10 to \$20 carbon price. And that's going to shift the baseline. It's going to shift perceptions of what is reasonable, and I think it will be interesting to see the degree to which that happens, and how that future negotiation plays out as a result.

The other implication is that we're going to have to do this over again. This is actually the second round of cap and trade Section 111 litigation that has been unresolved. The Bush administration tried to regulate mercury under 111(d) using a cap and trade approach. That litigation was resolved on other grounds. We never really got to the question of whether it was OK and how. We didn't this time, and what that means is, if the existing Clean Air Act is the tool in four years or eight years, we're going to be right back in court spending three extra years or so fighting over these questions, which is probably good for my students and their billables, but not necessarily great for the country.

In conclusion, we're not going to answer the big questions that we have about the Clean Air Act now, because courts don't issue advisory opinions. States are going to act on their preexisting preferences, and that's going to lead to increased divergence, to some degree spurred by the Trump dynamic. Cooperation on regional energy issues is made more challenging without shared carbon goals. I think we're seeing that

dynamic play out in the WECC right now. And it's extremely unfortunate, because there are enormous gains to trade, and we'll have to see whether the forces that are driven primarily by California's RPS ultimately push the states together--whether the gains from trade get so great that these anxieties about greenhouse gas emissions can be overcome. And eventually, when we finally get around to creating some certainty for the power sector on this question, I think the federal action is going to be harder, because the states are going to be more different than they are today. It's likely to be more stringent than it would have been under the Clean Power Plan, and we're going to face yet another litigation delay, because we haven't resolved these questions. So on that happy note, I'll wrap up.

Question: I didn't quite understand the argument about the legal status of the current appeals court decision. I clearly understand that if the EPA starts a new round, goes through public notice, and comes up with a revised version of the Clean Power Plan, and then files it a year or two hence, then that will be the law, and then we'll go forward with that. What I wasn't sure of is what happens in the interim, because I thought EPA or the Department of Justice was asking the appeals court not to rule on the current case, and I didn't see that as a constitutional principle, because it's certainly an active case.

Speaker 1: The EPA has gone into court and asked the D.C. Circuit to wait, and to not issue a decision. Frankly, I think many of us expected the decision by now. The rationale for waiting is that EPA has put the rule on review, and they have said that they would like the court to wait until the review is completed before issuing a decision. Essentially, what that's saying to the court is that this case has a possibility of being moot because there is not a rule. And therefore there would be no standing of the parties to sue over a rule that had been revoked, or, actually, there would be no standing for the parties to continue to try to defend the rule. And so I think

it's safe to assume that EPA is going to revoke the rule in some way. And I think the court probably is pretty clear on that.

What that means is that we're very unlikely to see a decision on the substantive issues that are at play from the D.C. Circuit. Because the court is going to wait to see what EPA does, at a minimum, and at the point where there is no longer a Clean Power Plan, the court is not going to rule on issues related to statutory interpretation of a rule that's been revoked.

Question: I agree with that, but I'm not a lawyer, but I don't see it as a matter of constitutional law that they couldn't choose to rule now.

Speaker 1: Well, the rationale for not ruling is really driven by the case in controversy requirement, and I think it's a compelling justification right now. They could certainly decide to rule, and there have been cases where there are exceptions to the basic limitation on the courts issuing advisory opinions, and this is kind of a grey area, perhaps. But that's my guess about where the court is going to land on this question.

Question: You use WECC as your example. Do you have additional comments on the Canada-U.S. alignment there? Because it's not just what's happening in the states related to energy policy, but it's also the differences, or, in the case of California, maybe the similarities, with Canada. I just wondered if you wanted to comment on that. And I'm happy to have it as a discussion later.

Speaker 1: Let me think about it and I'll respond to it in Q&A.

Speaker 2.

I'm going to follow up on some of the things that Speaker 1 talked about and get a sense of where states are right now.

The funny thing about the new administration, the theme of the NARUC meeting this year when referring to the new administration, was, "Ain't nobody knows nothing about nothing." And that's kind of true. I'm trying to figure out what the direction is going to be, not necessarily on the Clean Power Plan or on some of the rules, but on some of the policies that will really affect some of the energy trends going forward. What do they do to try to put coalminers back to work? Are there policy initiatives they're going to make after zeroing out a lot of the DOE budget?

The Paris Agreement is not really much of a driver yet. It's interesting that it wasn't part of the executive order. There's lots of discussion about whether to stay in that agreement or not, and a lot of pressure on the White House to actually stay in. It's not a driver yet, in terms of policy.

And then there's the Clean Power Plan and the myriad of options that are available to states as they go forward and we do a lot of direct work with states looking at their energy and environmental options and how they proceed, working before on the Clean Power Plan, and now kind of looking forward without the Clean Power Plan at what states are going to do. It's fair to say that states are really, no pun intended, all over the map on this, as Speaker 1 pointed out. States are moving forward in ways that you wouldn't expect some states to do, not necessarily for climate reasons, but they're going to move forward on policies that will have a climate implications.

We've already talked about the D.C. Circuit. My take on it is that, as Speaker 1 just said, the motion to hold the case in abeyance does not have to be granted by the D.C. Circuit. They still could rule any time after they deal with the Motion to Hold in Abeyance. I agree with Speaker 1 that now that motion's been filed, although they don't have to grant it, I think it's

probably likely that we won't get a decision out of the D.C. Circuit.

If there was to be a new rule, if you follow where the arguments were in the case, you're really looking at something like a building block one only rule. So, inside the fence line, what improvements could power plants make actually within the grounds of their own plants? Obviously, a lot fewer reductions could come from something like that. But for Mr. Pruitt and for the folks that challenged the rule, that's the argument that they were advancing in the D.C. Circuit. And, obviously, whatever gets done is going to be challenged by certain states, by environmental organizations, and we'll talk about, a little bit about the endangerment finding in just a minute, which overlies all of this.

So, on revisiting the rule, there are two schools of thought. Either they already know exactly what they're going to do, or they don't. I don't know which one is correct. Obviously, they're not going to show their hand, because if the idea is to revisit the rule and revisit the underpinnings of the rule, you don't want to show your hand by saying, "We're going to do this review and then we just won't proceed with anything." As the administration is learning, things that they say outside of court can matter to them when they get into court, as happened with the immigration rule. The same thing would be true here. You wouldn't want to show your hand if you don't have to.

It's not exactly simple just to eliminate the Clean Power Plan, because of all the litigation that will happen. Other people will push this. Much of it hinged on the endangerment finding which, curiously enough, was not part of the executive order. That was some of the discussion happening beforehand. Would the administration seek to do something legislatively that would do away with the endangerment finding which was used by the previous EPA as a justification for proceeding forward with the 111(d) and 111(b) rules?

The endangerment finding will kind of shadow everything, because if you're an environmental organization, or you're one of the states that already spoke out against the executive order, your justification for trying to force EPA to do something would be to use the endangerment finding that the Supreme Court has already ruled on. They will argue that that was in a transportation context, but I'm not sure that that's a great argument to use. This will be tough to do through Congress, though, to try to do something with the endangerment finding, and that may have been one of the reasons, in addition to the fact that the case is still active at the D.C. Circuit, to leave that out of the executive order, if they do want to make a move on that.

You heard people talk about a carbon tax. Some former officials went to the White House and tried to pitch a carbon tax. They got the reception that you would expect them to get at the White House, and based on the things that we hear in Congress it's highly unlikely for a variety of reasons.

Now, for state activity, first I want to do a little walk back, because I think we've actually been here before, talking about this, and as long as we're all going to quote Yogi Berra, it's, "Déjà vu all over again," as he famously said once. We've been through this before, during the George W. Bush administration, where states were really in the same place. They perceived that there wasn't going to be anything happening federally, and so states kind of ended up in different buckets, proceeding or not proceeding, working on different things. I think the politics are different, arguably worse, now than they were then. But I think the trends toward cleaner energy or towards lower GHG emitting energy are fairly well baked in right now, and that's going to drive a lot of the action as well.

Back when RGGI first started, the Western Climate Initiative followed, with a lot of states

who were looking to do more than RGGI, because they were looking at economy-wide not just power sector only carbon emissions. And there was the Midwest Governor's Accord, which was also economy-wide. That was six states plus the province of Manitoba that were looking to do a Midwestern kind of cap and trade program. And then there was the Three Regions Group, which wasn't so artfully named, so they came up with "North America 2050," but the idea behind the Three Regions Group was to take what RGGI was doing, take the plan that was worked out but never adopted by the Western Climate Initiative, and take the plan that was worked out but never adopted by the Midwest Governors Accord and see if there was a way to knit those together so that you would have kind of a de facto cap and trade-type policy. Well, the elections happened in 2010, and at the same time Waxman-Markey started going through, and so two things happened. One, a lot of the governors who had been very supportive, both in the West and in the Mid-West, of doing something with climate, they weren't there anymore. In fact, the guy from Minnesota and I kind of looked at each other, every other of the six states was kind of blown out of our process and we said, "Well, what do we do now?" So instead of three regions, we became two regions and a couple of guys. [LAUGHTER]

And then with Waxman-Markey or McCain-Lieberman, there was the thought that there was going to maybe be some Federal policy, and so the effort to do those regional things and knit them together really fell by the wayside a little bit. The interesting thing is, you also at this time had a lot of the state RPSes. The more progressive of the states on climate policy were doing things within their own states to try to drive that policy and I think Speaker 1 is right is saying that you're going to see that again. There was even a group that Georgetown convened that was rather immodestly called the "Leadership States," who were a group of progressive states that were looking to do policy

and not trying to do the same policy, but trying to understand what everybody else was doing to see if there was some kind of coherence that they could bring out.

So what's been going on? With respect to the Clean Power Plan and with other energy initiatives, there has been a lot of recent state activity in spite of the fact that there's a lot of federal activity that's been going on. The western states, convened by the Center for New Energy Economy at Colorado State, have been looking at other energy issues and the intersection of energy and environmental issues. Southern states have been convened by the Nicholas Institute at Duke. Again, looking at something broader than just a Clean Power Plan type of focus. Both of those groups have been meeting now for more than a couple years. We're very involved with the Bipartisan Policy Center and a group of states in the MISO footprint called MSEER, the Midcontinent States Environmental and Energy Regulators group. That group has been meeting since June of 2014, right about the same time that the proposed rule first came out for the Clean Power Plan. The idea there was to try to figure out if there was kind of a Midwestern approach to that. This group has made comments to EPA on the different iterations of the Clean Power Plan.

A year later, some folks in the PJM footprint came to us and said, "We see what you're doing in the MISO states. Would you do the same thing in the PJM footprint as well?" So we're partnering with the Nicholas Institute. That group has been meeting since June of 2015.

And, in addition, predating all of those groups in the Midwest, there was a group called the Midcontinent Power Sector Collaborative, and that's a big stakeholder group. That's not just state officials. It's a bigger stakeholder group that involves NGOs and utilities and munis and co-ops, the idea being to see if there was some kind of Midwestern approach. This group

actually started with the idea that EPA was going to propose some rules.

The reason I mention all these groups is that they're all still meeting, in spite of the fact that the Clean Power Plan, for all the reasons we've talked about, may not exist in that form or any form, or at least in the form that we've been talking about. These groups are still meeting, with the idea being to talk about other issues where there are intersections between energy and environmental issues. The Power Sector Collaborative made several comments to EPA, and has been credited (probably other groups were, too) by EPA for coming up with kind of the trading-ready approach that was part of the final rule. And they have done a lot of white papers on various issues, and they're still working on a variety of issues now. And modeling was always a part of that, not just things like rate versus mass, but to understand how what my neighbor does really affects me and my own state. I think that's been a large part of these efforts, and I think it will be going forward, although you won't be just modeling different Clean Power Plan things. It will be looking at some other potential issues as well.

So I think the philosophy is to talk to states and meet them where they are, and that's going to be different for every state. Some states may want to proceed with full-blown climate action plans or something they want to do. Others will not. Others will do climate-related policies, but not necessarily for climate reasons. They'll do things like add more renewables or add more energy efficiency, but they may do that for other reasons.

In terms of the trends that states are watching, coal is still in a tough place. There was a good article in the Washington Post yesterday about that. As I mentioned earlier, it's one thing to sign an executive order and say that we're going to bring back coal and put people to work. The question becomes how you do that. A lot of recent articles talking about that (and it was in

the Post article yesterday) say that if you want to do a new coal plant (and there isn't anyone really lining up to want to do that right now), who's going to finance that? Realizing these are 30, 40, 50 year decisions that the utility companies are making and that the PUCs are overseeing, and if in three years you've got President Booker or President Warren, there's a pretty good feeling that things may swing back just like they have in the past, and are you going to bat that the current mode of trying to help coal and trying to move that forward is something that's going to last? I don't think the trends would say that that's what's going to happen.

And it's not going to happen a lot because of natural gas prices. I mean, one of the really curious things to us has been (and states are trying to figure this out as well) that natural gas prices have been low. All the forecasts that you see, they may not be as low as they are now or have been, but they're going to remain in that range, where it looks at natural gas is going to continue to dominate from a cost standpoint. And the administration is talking about doing a lot of things to support gas. Maybe realizing, maybe not, that that's the single biggest way to really kill coal even more than it has been, but I don't think they've actually sorted through those things yet.

The administration could choose to work on and try to finance some new technology. Things like carbon capture with enhanced oil recovery. There's a 14 state working group on that that's done a couple of pretty good white papers on things that could be done to really help jump start the carbon capture and enhanced oil recovery side of that.

But there's a pretty big financial gap there right now between that and traditional coal plants, let alone with respect to natural gas or even renewables in a lot of places. And the renewables costs are going down. That's something, obviously, that folks are watching.

Wind and solar costs are still dropping. That's likely to continue. I don't see a move to eliminate the PTC or the ITC, although when they do major tax reform, who knows what might be on the table.

And then a lot of states are going through utility business model reform and flat demand is one reason in a lot of places. But a lot of time the reason is that they're trying to get more distributed energy on the grid, and figuring out how to do that and how to make that work from a business model standpoint, and the fact that a lot of customers large and small are demanding cleaner energy, and that's forcing people to really take a look at how their business model will work with that.

And then, with respect to utility approaches, we've seen a number of executives that being quoted in the last few months saying the election doesn't really change where they're at. I've been in lots of conferences, like you have, and heard from lots of people that said that it's not going to change their approach for the reasons that we talked about earlier, with the long lead time and the fact that the political winds can and have changed from time to time.

So, what are states doing? What will they do? It's clear that they're adding clean energy to their mixes and their portfolios for a variety of reasons. We've got the clean energy standards in the nuclear plants in my state of Illinois. And New York has done that. Ohio and Connecticut, even as we speak, are looking at measures to try to support the nuclear plants. Pennsylvania and New Jersey are probably right behind them in terms of trying to work through this and see if there's a way to keep existing nuclear plants going.

That's being done for a variety of reasons. In my state, I'll submit to you, it wasn't a reliability issue and it wasn't a greenhouse gas, zero emission issue. It was an issue of jobs and

property tax base in the areas where the nuclear plants are located. They provide a lot of both, often in areas that don't have a lot of other high paying jobs or high property tax base properties. And that was something that really carried the day.

So, energy efficiency and demand responses is really making an impact as well.

There has been some talk about a carbon adder in the RTOs and ISOs. There are both legal and internal (small p) political issues involved in doing something like that. And then FERC still doesn't have a quorum. We don't have any nominees. It will be very interesting to look at the philosophy of the nominees as they go forward to see if states are going to start taking some of these actions or the RTOs want to take these actions. What's the philosophy of FERC going forward on that?

And the last thing I'll leave you with in talking about the states is a thought about why it's not easy just to put them into categories. I was talking with two folks in what we would classify as very red states, and one of them was talking to me about the amount of wind that they're doing in their state and how they made a concerted effort from their state to do that over the last few years and they really have made great strides. And he said to me, "We may not be doing it for the same reason that everybody else is. We're doing it because it creates jobs here in our state. We've got a good wind resource, and from an economic standpoint it makes sense. And the bottom line is, what difference does it make what our rationale is for doing that?" The answer is, it doesn't make any difference what the rationale is for doing it. That's part of that "meet states where they are" kind of philosophy.

The other anecdote is about the governor of a very red state who was talking about wanting to double or triple down on wind. This person's a climate denier. He wants to do it, not for climate

reasons, obviously, but he wants to do it because he's trying to attract a lot of businesses, data centers and other big users, and the corporate entities are telling him, "We want access to 100 percent clean energy." And so he's doing this as an economic development tool for his own state. And, again, it doesn't really matter what reason he's doing that for. That's going to be added into the generation mix in that particular state.

I think you're going to see a lot of actions like that, which is why I say that the trends are more so than they were back a decade ago when we were doing this. The trends are more toward clean energy and toward states trying to do that, even if the reasoning isn't the same, and even if the politics toward anything that has to do with climate might be a little worse than they were back then. So, thanks. I look forward to discussion.

Speaker 3.

Good morning everybody and thanks again for the invitation to come back and revisit this. I think you can probably get the punch line from the title of my presentation. Does it matter if we have the Clean Power Plan? No, it probably doesn't.

I'll give you the punch line, and then I'll go through the evidence supporting this. The first factor (which has been brought up by the previous speakers) is that we have basically slow, flat, or declining power demand in this country, in terms of total megawatt hours. It's not about peak demand. It's really about total energy. The so-called relationship between GDP growth and electricity demand growth that everybody assumed was there has been shattered. In fact, it's been in the process of being shattered over the last several decades since World War II, and I'll show you that. But where are we going to get new power demand from? What's going to have to happen? Well, there is still some relationship, as weak as it is, with GDP growth, but given the factors that would drive GDP growth--population growth,

productivity growth, et cetera--two percent's probably all we're going to get out of GDP growth on an annualized basis. I think we need to come to grips with that as a country. Our working age population is kind of leveling out. We've got a lot more retirees. Productivity growth, after the 90's with IT, has just kind of leveled off again.

We're probably not going to see dramatic growth tied to GDP, so what would have to happen? Well, the electrification of the transportation sector could drive demand growth. But that just means we're taking carbon dioxide out of one sector, transportation, and putting it into the electricity sector. And of course this is a global problem and it's a multi-sector problem. It's just not about electricity.

The second factor is gas market dynamics. What is actually driving these gas prices? We hear about the shale gas plays, but technology has really ramped up, and it doesn't seem to be letting up anytime soon. Producers in the Marcellus, and the Utica particularly, can punch a hole, they can frack it, and, at \$2 gas or less, can make their money back in nine months. That's just stunning, when you think about it.

And then we'll take a look at some of the forward market forecasts, suggesting relatively low prices in the future. And then there are other technology trends. Combined cycle gas technology has improved by leaps and bounds. And, obviously, when you see all of this, and you put it all together, you find that the Clean Power Plan's not binding. It's not even binding if we have a bunch of nuclear retirements.

First, let's think about demand. This chart shows demand in the United States--total retail sales from 2000 to 2016 and then the AEO 2013's forecast and the AEO 2017 forecast. Now, you see demand kind of moving along, growing at a pretty good clip up until about 2007. And then, of course, we have the Great Recession. After that, demand bounces back a little bit. But it

doesn't go back to that same trajectory. It flattens out. In fact, the annualized growth rate from 2007 to 2016 is negative. Almost two tenths of a percent per year, but the whole point is that demand growth is basically flat. And yet, our forecast (and, by the way, EPA's forecast under the Clean Power Plan) had demand growing at close to one percent per year. We're not going to see that.

So if you take that much energy out of the economy, by definition, you're probably going to take a lot more carbon dioxide out electricity production, just from that alone. This is a nationwide issue. I'll use some PJM data, since I used to work at PJM. And this is even more stark. This is largest electricity market in North America. And, again, you see the same trends. Now, this chart goes back to '98. We got through 2007, and demand was really growing. And then we had the recession. But unlike nationwide (we do have demand growth in places like Texas and the Southeast and some parts of the West), in the Northeast, the old industrial areas never bounced back. In fact, in the last four years, total electricity demand in PJM has been at levels we last saw in 2004. Demand has literally been destroyed by the economic downturn and, I would argue secular changes in the economy.

In terms of the forecasted total energy growth in PJM (and I've shown the forecasts going back to 2013 and all the way through 2017), you see that, even though demand growth is forecasted, the amount of forecasted growth just keeps going down. And the forecasting staff at PJM has made a lot of adjustments to try to get closer to where things are going, but, even so, the annualized demand growth rate between '07, at the peak, and 2016, is six tenths of a percent negative. The forecast in 2017 is only for three tenths of a percent growth. That's actually much more realistic than even EIA is, at this point. And yet, I would argue, given the secular changes that have happened, that's pretty damn optimistic at this point.

So, again, if we're taking demand out, that's going a long way toward meeting the "energy efficiency goals" from the Clean Power Plan, whether you agree with them or not. But whether it's energy efficiency, or just that demand is not there, it's observationally equivalent.

So, here's a graphic that I first developed about four years ago, and it only goes through 2012, but I figured I'd dust it off again. This is taking data from EIA and looking at total net generation as a proxy for load growth, going back to the '50's, cutting it up by decade and then running an ordinary least squares regression through it to look at the relationship with GDP growth. And if you do this by decade, you see that there is a positive relationship, although it's not that great, to demand growth. And it varies by decade, but what's interesting is the intercept term. It's the intercept term which is capturing a whole bunch of other things. It's capturing, in the '50's and '60s, the population boom. It's capturing the electrification of our lives. It's capturing the post-World War II industrialization of the United States of being the industrial might to bring Western Europe back after starting with the Marshall Plan in the early '50's and continuing forward into the '60's. And then you start seeing it dropping down, little by little, each year. In the '70's, it drops down a little bit more. Now we're seeing the second generation of electrical appliances. They're a little bit more efficient. The same is true in the '80's, and then you get to the '90's, and there's almost no relationship to GDP growth. It's all in that intercept term. It's all about IT and other things that are going on. Then we get back into after 2000, and, again, absent any GDP growth, demand growth would be negative.

The whole point is that there are secular changes going on here in demand growth that have absolutely nothing to do with economic growth. Which also tells us that we could actually reduce

energy demand, and we're not going to kill the economy, probably.

What about gas? It's no secret that we've got this huge uptick in Marcellus shale gas, Utica gas. What's interesting is that we've had pretty steady production out of the Permian Basin, which is now going to see a lot more attention with all of the oil there, and so now, as we start getting more oil E&P activity, we're probably going to see a lot of associated gas E&P activity. That's only going to ramp up production in that area.

If you look at the productivity, this is where it just is mind boggling. Looking at the Marcellus and Utica shales, there's almost exponential growth in productivity per well. We don't have to punch as many wells to get the same production. We could punch one well and get six times the production, seven times the production that we could a mere 10 years ago in these areas. And now we're starting to see that uptick happening in the other, older, shale gas plays, in the Eagle Ford and the Haynesville shale.

We're seeing these huge productivity gains, and eventually they'll have to level off, I would assume. Part of what's leading to this is a standardization in drilling. Previously, in both oil and gas production, there wasn't this standardization in drilling equipment and replacement parts. And everything was all very unique to that particular site, especially offshore sites. Now we're seeing a standardization across both industries, gas and oil production, and that brings down the cost of drilling these wells, on top of the productivity gains we're seeing with just fracking.

So, where does that leave us? Well, obviously, it leads us to low natural gas prices. The green series is the forward curve, annualized, that I pulled from the Intercontinental Exchange at the end of February. Gas prices, by 2029, on an annual average, might get to \$3.25, \$3.30, maybe. The highest you'll see, on a monthly

basis, out to 2029, is \$3.50 for one month, and that's usually going to be in the winter months. That's at Henry Hub. (By the way, Henry Hub, while it may be the reference price that we use for natural gas, is now actually trading at a premium to every place else in the United States. It's actually one of the most expensive places for gas.)

So, I'm showing you the constrained price for gas. I'm not showing you the production areas for gas, because I don't have anything to compare it to. Nobody does long term forecasts on the production areas. But if you think about the basis differential that we've seen historically--let's say 50 cents to a dollar in the Marcellus production region, depending on time of year--now you're talking about \$2 to \$2.50 gas over the next 10 plus years. That really makes combined cycle gas generation pretty competitive with anything out there, even as coal prices may be falling.

So, let's think about gas-fired technology. There's existing technology, and there's new technology. Let's think about existing costs. This is taking data from the Environmental Protection Agency, from the IPM modeling version 5.13 base case documentation. It's available to everybody, and what's beautiful about this is that we have going forward costs for whole units of different ages and characteristics, based on their environmental attributes--what kind of equipment they've got on the back end to control emissions. We have, specific to every operating nuclear facility, going forward costs based on AEO and FERC Form 1. And then we've got some more things for existing combined cycle gas.

So, if we think about competitiveness and where this is going, existing combined cycle gas has pretty low going forward costs. Now, Speaker 3 on the last panel made the argument that a lot of these gas fired generators may not be making a whole lot of money, and they may not be making the money that they promised, but

they're also not cash flow negative either, necessarily, because the costs are sunk, once they build the unit. Going forward costs are next to nothing, compared to a coal unit or a nuclear unit, especially. Compared to a nuclear unit, an existing combined cycle gas unit has one eighth of the going forward cost. That's a pretty stark difference in a competitive environment.

What's happening to overnight costs for new combined cycle facilities? The costs are coming down, in real terms. The fixed O&M costs are falling. People are getting better at this. They understand how to operate the units. The variable O&M costs are coming down. The heat rates are coming down. They're becoming even more efficient. Not to mention the economies of scale. If I actually looked at the size of the units, over time, in 2010, when EIA had the study done, a conventional combined cycle unit would be just over 400 megawatts. Now it's closer to 600 megawatts in size. So, you can actually get more bang for your buck, over time.

So, where does this all leave us? Here's the real punch line slide, and this comes from the PJM Clean Power Plan report that I worked on before I left PJM. And we ran some low gas price scenarios (and the "low" gas price scenario actually uses higher gas prices than what I just showed you in the forward curve, by the way). Now, with the existing source targets alone, we ran two cases for the low gas scenario. One, where decisions were made long term over the 20 year horizon, and one, where short term decisions were made on entry and exit. The blue dash series reflects additional coal retirements and 14 gigawatts of nuclear retirements in PJM alone. Let that sink in. 14 gigawatts of nuclear retirements. The existing source target is still not binding. If we combined it, if we used the existing and new source targets that EPA proposed in the Clean Power Plan, because of the multi-year nature of compliance, really, it doesn't become binding until 2027, with 14 gigawatts of nuclear retirement. There's a CO2

price of zero in this scenario, and we can meet the Clean Power Plan targets out through 2027.

Now we've got ZECs, and, of course, with renewables, we've got RECs, and, if you believe some of the people on Wall Street, they think Trump's going to come up with DECs (Dirty Energy Credits). [LAUGHTER]

This projection assumes, by the way, no dirty energy credits. We can meet the Clean Power Plan targets even with a lot of nuclear retirements.

And so where does that leave us? If we let markets do what they need to do, sure, we get nuclear retirements, but guess what? There are a lot more coal retirements. This chart is just showing you the gas prices that we used for the low gas price case, which came from IHS CERA. We pulled them in February of 2016, so they're quite dated, but the gas price trajectory is actually higher than the current forward curve from the Intercontinental Exchange.

What happens when you see those low gas prices? Obviously, you see more combined cycle new entry. That goes without saying, but you also see more coal retirements that go along with the nuclear retirements. In some ways, the coal retirements that occur with low gas prices offset a lot of the nuclear retirements that take place in this case. So, again, this is sort of the argument for letting markets work, just staying out of the way. Markets will react. You'll have the coal retirements. You'll bring in the new combined cycle gas, and if the nuclear units really are as expensive as they look... We can still meet the climate goals.

And so, without the Clean Power Plan, given the current trends, there's no reason why we can't meet those targets. Now, those targets were part of meeting the Paris Accord goals that the United States signed onto. There are going to be other factors, obviously, that will help, and Speaker 4 will talk about that. But, really, the

executive order doesn't change any of this, unless there's going to be an active role for (and I'm not making this up) DEC's. I mean, heck, we've got everything else. We might as well throw something else into the mix, right? I will leave you with that. Thank you very much.

Speaker 4.

Everybody basically said that the Clean Power Plan was at most marginally binding. I think that is true. One interesting question is, how much backsliding, relative to the trajectory that is already baked in, is going to happen as a result of the Clean Power Plan not being there anymore? The resource additions over the last few years have been primarily gas and renewable. And electricity wholesale prices have basically declined, and gas prices are low, which creates an environment that's good for gas and bad for coal.

Over the last few years, growth of renewables is beginning to outstrip the required growth of renewables to meet state-level RPSes. There are a number of reasons for that. One important one is that RPSes, as they are structured, are in many states actually not sufficient to meet longer-term greenhouse gas emission reductions goals or mandates, and so you can see states taking action to encourage more development of renewables, beyond what's required under the RPS, through long-term contracting, like in Massachusetts, et cetera, et cetera.

The other important driver is that, through a combination of technology progress and demand that may only partially be based on what we in this group might consider economics, the growth of renewables is significantly different now by virtue of demand from commercial and industrial customers. This chart shows the evolution from 2008 to 2015 of PPAs signed with C&I customers. Many of them are big corporations. Generally, these companies sign PPAs with renewables. They're willing buyers. There're willing sellers. These are economical transactions. Whether or not the price that they

pay under these PPAs is more than they would have to pay if they just signed a regular PPA for brown power is irrelevant. It means there's value to them in making those deals. And, given the size of the electricity sector relative to the overall economy, it may matter a lot more to them that they can argue to their customers that they're purchasing green or clean energy than what they might save by spending a couple of cents or a couple of dollars per megawatt hour less for buying something different.

I don't see this trend slowing down. These PPAs that have been signed are not sufficient, by any means, to have those companies that have committed to high renewable shares meet those obligations. So there are significant and additional growth opportunities that I think can come from these purchasers over time, independent, not only of the Clean Power Plan, but also independent of whatever state RPS is there to motivate renewable development.

Technological change is also there, and it's progressing for renewables. The most recent offshore contract in Denmark was for 48 Euros a megawatt hour. I was a testifying expert in the Cape Wind proceeding. That PPA was supposed to start somewhere around 200 and something dollars per megawatt hour. So that's a significant change. Chile is very sunny and high altitude, ideal conditions for solar, but the most recent solar PPA there was under three cents, so under \$30 a megawatt hour. And, basically, three to four cents a megawatt hour for wind.

As you probably know, in the U.S., it gets a little more complicated, with PTC and accelerated depreciation, but now PPAs are being signed for wind projects for around and under \$20 a megawatt hour. And so, increasingly, you could see that the renewables costs, by themselves, do not require any subsidies, and you can make a perfectly economic decision, even if you don't think about your customers needing or wanting green attributes to buy renewable energy.

So the emphasis on the signing contracts or building projects will increasingly be driven by just the underlying economics of the individual projects, which continue to be attractive and become more attractive. The one thing that's beginning to shift is the emphasis on what we all sort of loosely call "integration costs." That's an interesting sort of externality issue when people sign PPAs with each other--figuring out how whatever integration costs are not easily captured by some kind of integration study for a specific project are ultimately financed. I'll give you one example. The California draft Scoping Plan, among other things, includes ratcheting up the RPS to 50 percent, and perhaps even more. If you look at the assumptions about the renewable projects themselves, they're like \$50, \$60, \$70 a megawatt hour. When they translate that, ultimately for the RPS overall, the cost per ton of carbon removed is more like \$300 to \$400. There's a whole bunch of other investments that you have to make at the state level to make that work, in particular, a lot more new transmission, beginning to build a lot of storage, and that kind of things.

So I think that's an interesting question. As some of the states reach significantly higher penetration levels for, then some of these indirect costs are going to become more of a factor and more of a potential hurdle.

It falls to me to talk a little bit about the Paris Agreement and I think that there, the impact of not having the CPP is a little less clear. Obviously, the Clean Power Plan was the document that allowed the U.S. to become a signator, because it showed the kinds of emissions reductions that you had to show, at least as targets. There are no mandates to do this. So, what would happen if the U.S. withdrew, or just decided, basically, not to act on this? I think there are basically two possible outcomes. It is possible that the deal could unravel, or it's possible that the rest of the world could isolate one finger and one hand and basically make a

gesture to the United States and say, "Well, too bad for you. We're going to do this anyway."

It strikes me that, fundamentally, this climate skepticism is a phenomenon that's entirely limited to the United States. I don't see any other country where this is actually a discussion. There is an extremely widespread agreement on the underlying need to decarbonize, more or less, by mid-century. So, the major other parties to the Paris Agreement have that underlying consensus, and so there is a pretty good chance they will continue with the decarbonization. They will do so, also, because they see that as an economic development opportunity. They do see that there are technological changes, like the ones that I showed previous slides, that will lead to a transformation of the energy sector over the next couple of decades, and countries like China, but also countries like Germany, clearly see that as an opportunity to position themselves as major players in that new world.

I think the largest potential impact of the U.S. exiting the Paris Agreement or not working inside it actively is on the developing countries. It strikes me that financing the carbon fund, that part of the Paris Agreement, is going to be much more challenging now. It was already challenging when the U.S. signed on. The commitment was much better than the actual payments that were made. So I think that part of the deal is more in question as we move forward.

In conclusion, my personal guess, and it's really not much more than that, is the U.S. will continue to decarbonize, just because the underlying economics are pretty compelling. And climate skepticism is a U.S. phenomenon. I think there could be bumps in the road once countries hit renewable thresholds that create systematic challenges. You're beginning to see that, a tiny little bit, in Germany, for example, now. Not so much in Germany itself, but in the surrounding countries, actually.

In the U.S., not having the CPP won't mean that the carbonization trends will stop, as we have discussed. Coal retirements may be a little bit delayed, but there's no real reversal in sight. Renewables are becoming attractive. So I think it would take a deliberate act against economics to reverse the current trend, and that would be irrational. When you have things like Wyoming proposing an 85 percent minimum fossil fuel standard, that's exactly the kind of deliberate act that might reverse this trend, or to me the most frightening one is when the EPA's considering pulling the waiver on California, where you'd just have a deliberate act to sabotage the efforts by states, where the ideology or the philosophy or perhaps the rationale is different from what happens in Washington. I think that's really scary.

I'll end with some thoughts beyond that. This, to me, is reflective of a much more polarized U.S. now, where you have some states that think about economic development and growth as being very tied to low energy prices, and then you have other states that basically buy the evidence that Speaker 3 presented that by and large economic growth is now decoupled from energy costs and emissions. We can probably all identify, relatively easily, geographically what the distinction is.

Having worked a lot in Saudi Arabia and in Norway, I really think about this as sort of the Saudi Arabia strategy versus the Norway strategy. We do have a lot of energy resources in this country. So there's really a choice, and it seems to me that the states polarize according to whether they go down the Saudi Arabia route, where you're trying to encourage very low domestic energy costs to then foster economic growth, or whether you say, "That's a great resource. Let's make as much money selling this stuff as we can, but let's incentivize a much more diverse and energy-decoupled economic growth." Even in the sort of Saudi Arabia states, it turns out that there are these companies...Wal-Mart is in pretty much any state, and Wal-Mart

has this pretty high renewables goal set for itself. So, even in those states, you see, increasingly, demand from customers and from big employers to move in that direction.

So I would define the polarization in even starker terms. It's the polarization between a relatively small group of people in a set of states, on the one hand, that have this view of development, of economic growth and well-being tied to low energy costs, and then you have a lot of other players in those same states and a lot of other states who have this other view.

I actually think, on the electricity side, that the train has left the station. The economics are in place. There is a market dynamic that will probably not require the CPP for decarbonization, and it will just keep going until we probably reach the kind of shares of renewables that we now see in places like California, or are beginning to see in California, or in Western Europe--20, 30, 40 percent renewables, intermittent renewables, when you have to build new infrastructure and figure out how to integrate all that stuff.

I think the much harder issues are decarbonizing the sectors that are not traditionally electric. The Clean Power Plan doesn't do that at all, but that doesn't take away the likely need to work on those issues. Transportation is a very complex issue that involves very, very long lived investments in new infrastructure. Heating is the other big sector. I think that, going forward, completely independent of this Clean Power Plan, that's where the emphasis needs to be.

It's exciting to come full circle. That is where new growth could be quite significant for electric utilities, going forward. And, if I'm right, decarbonization of the power sector by itself is something that we've kind of figured out, technologically and we're at a threshold where it makes sense economically, if not today, then it will do so in three, four, five years. Then

there is a really nice combination of solving our greenhouse gas emissions problem through a combination of continued rapid decarbonization of the electric sector, which will not be much more expensive, if at all, than not decarbonizing. And then working very hard to shift demand from traditional emitting fuels, oil and gas for heating and transport, onto relatively decarbonized electricity. And I think that's really where the action needs to be, and I think that's where the big opportunity is, actually, for the utilities.

Question: You talked about overproduction vis-à-vis RPS standards nationwide. How much of that is actually due to Texas? Is that accounting for most of the overage, or are other states doing that, too?

Speaker 4: Other states do that, too. California is currently on a trajectory to overshoot, and they're banking a lot of allowances. So that's one other big state that has overage.

Comment: Minnesota's another one.

Speaker 4: Yep, Minnesota. And a lot of Mid-western states are building lots and lots of wind. I haven't done the gigawatt hours spread, but I think it's not just a Texas phenomenon.

General Discussion.

Question 1: I want to ask a question that is focused on a more optimistic view of what happened on Tuesday, and which I actually considered to be good news. I thought the Clean Power Plan was way too expensive for too little accomplished, and very disruptive for accomplishing, when you got right down to it, almost nothing, if you really care about this.

And what do I mean by that? Well, first, the Clean Power Plan, as you know, is not a plan. It's a set of standards and criteria, and then the states would have to develop plans. So we don't actually know what was going to happen under

this order. And we could imagine an implementation which was fine, and that everything would work well, and you can imagine an implementation which would be the death of civilization as we know it. [LAUGHTER] So, those things were all in this frame of reference. And I wasn't sure where I was going.

Second, I personally found it extremely difficult to read the Clean Power Plan when it came out. There's a very high level of double talk in the Clean Power Plan. I was never quite sure about whether or not this was completely disingenuous, or they just didn't know what they were talking about. I think there was a real set of problems associated with that document that could, in principle, cause conversations to be much harder, going forward, because of all the double talk about what was going on.

And then the other thing about it that always bothered me was that it accomplished so little, and so you get into this crazy situation where we're talking about targets, and then the targets are low, and then we accomplish the targets. And I think that reveals what the problem is. Targets are the wrong way to think about the problem. I don't care what the percentage of emissions of carbon dioxide is. I'm concerned about the social cost of carbon, and we should be charging the social cost of carbon, internalizing it, and if that drives carbon emissions to zero, that's fine, and if carbon emissions go up, that's fine. We want to internalize the social cost of carbon, and the implicit carbon tax that's embedded in the Clean Power Plan is way too low.

So, my question, with all that background and my prejudice revealed, is, is there a chance that we could actually have an improved conversation and a set of policies, going forward, given what's actually happened, where we don't have to sit around and defend the indefensible, or is the other view of this, which many of my colleagues share, correct, which is

that the CPP was the best that you can get, and if you don't have the Clean Power Plan, you're going to have Dirty Energy Credits, and the world is going to be worse, and all that kind of thing.

So, I find myself actually more optimistic, relieved--I think there's an opportunity for sort of a fresh start in this conversation. But this may be a minority opinion. I'd be interested in the views of the panel.

Respondent 1: I have two comments. One, of course the Clean Power Plan, philosophically, was like, we couldn't do the pure thing. There was no chance in hell to do this the normal way, given the political situation in Congress. So, this was an attempt...I don't think it was a very elegant attempt, in the end, even though I think the final rule was better than the proposed rule. It definitely not an elegant way to do this, because of all the things you said.

I think it still would have been better than nothing as an insurance against backsliding and DEC's and the other sort of crazy things that might happen.

The other thing I wanted to point out is that I would have exactly the same reaction to Obamacare, and would have exactly the same reaction to the Brexit vote, in the sense that repealing Obamacare is a very understandable response to a policy that is also extremely far from being optimal or even very good. And the institutions of the EU are extremely far from being optimal or being good. But I also think, politically, there is a certain amount of capital that you have to get to something that's better than the status quo, and, once everyone has done that and is exhausted, then saying, "All right. Push the reset button. Let's try again with something better..." So, especially, as I said, as an insurance policy, I think it was better than nothing, and if it wasn't binding, then it wouldn't have been very costly to implement.

Respondent 2: I would agree with pretty much everything the questioner said about the design of the Clean Power Plan, but I view its role as different. The way I think about it is, it's more of a bargaining chip. The fact is, it is, it would have been very burdensome. It would have been disruptive to electricity markets. It would have created real problems at the state borders in common market regions. And I think the hope was that all that would tend to push a small set of Republicans who are at the margin on these questions, who look at the Clean Power Plan with horror, toward being willing to trade that, and perhaps other EPA greenhouse gas regulatory authority, for something that you and I both would prefer.

The problem now is that there's nothing to trade. I guess there's Clean Air Act authority, but, given the outcome of the election, there's little urgency to that bargain. And I think that's also why you saw Senator Whitehouse, Sanders, and Boxer developing these pieces of carbon tax legislation that have been sort of floated around Congress the last few years--not because they felt they would pass, but because they wanted a vehicle around which to have a negotiation when the time came that there was a final Clean Power Plan that would survive legal review. And unfortunately we don't have that, and we're not going to.

Respondent 3: The Clean Power Plan was certainly not a fun read, and it's certainly confusing in many of its aspects. I think it was really a reaction to how Waxman-Markey was so ignominiously shot down and buried very quickly. It just wasn't possible to do the right thing and put a price on emissions (even though Waxman-Markey had its own warts, what with having both a cap and trade program and a renewable portfolio standard nationwide).

I hadn't thought about this as actually being a more hopeful or optimistic time with respect to this. So, I'm glad, and I'll take the toaster away from the bathtub now. [LAUGHTER] Think

about it this way. The way things are going politically, one could imagine in 2018 a wholesale shift once again in governance in this country. And perhaps we could move something that gets closer to the ideal. Certainly, the social cost of carbon would be a start, but I think we know that there's a huge segment of the political class as well as voters who now buy into this idea that anything like a price on emissions looks like a tax, and taxes are just evil. We know that's not really true in reality, but that's how it's going to play out politically.

The Clean Power Plan might have given us a balkanized system, but I'm actually now worried that we have a more balkanized system. And if I were back at PJM, from a systems operations perspective, now what do I do? This was actually my worst fear, that we would have a balkanized system, and at least with the final Clean Power Plan we had agreement, and the states finally came around.

Yes, we should all do the same thing. We should make this easier, so we can all trade. Now, we're actually in a worse place, where you have states doing all kinds of different things--some states doing nothing, some states taking aggressive action, and that's going to have impacts on the power system and operations and markets that we don't know anything about yet, until we see some of these plans really start getting fleshed out.

Respondent 1: I spent so much time working on the Clean Power Plan and parsing every word, so I understand the complexity of it, but I actually think, from all the work we were doing and the work from the other groups that I mentioned, states were really getting a pretty good handle on what the impact was going to be for them, and what their choices were. They were getting lots of good input in their own states from utilities and NGOs and from other people as well.

Yes, it was complex. I think part of that was due to the fact that EPA wanted to have something that they thought more states could buy into, so, giving them greater flexibility in how they did it, which may look like a nightmare, in terms of implementation, if you talk about "rate versus mass" and some of the other decisions that they made, but I think most states were actually kind of coalescing around a mass-based approach. I think that was pretty much true. And most states had adopted the idea of trading. And so I think what you would have seen is a couple of things from that. One is, less of the nightmare scenario of balkanization, and also lower costs.

And all the modeling that was being done was showing that you were actually going to achieve lower costs, to the point where it got to the questioner's point that the implicit carbon price in there was really too low. But I think that if you listen to EPA's explanation, Administrator McCarthy said that she wanted to give a further push to the markets, the way that the markets were already heading, all the trends that we talked about this morning. And she wanted to give states a lot of flexibility.

I think it was a sign to the world, as Speaker 4 was talking about with the Paris Agreement. And those of us who are recovering environmental agency administrators also know that Federal regulations, once they get in, also get ratcheted as time goes on. And so, yes, maybe it would have been nonbinding now through 2030, but there's also the opportunity for review every few years. So, I think that was some of the thought process.

I'm less optimistic in terms of the conversation from now on. I think you've got more than 50 conversations now, and you're going to see this kind of (we've already seen it with the nuclear plants) one-off things. And what's happening in the merchant states with nukes is going to happen in the vertically-integrated states, too, as they start to come up to their licensing time, and they've got fairly large CAPEX requests that

they're going to make. You're going to start to see that thing happen, not just in the merchant states, but elsewhere.

The politics are so strange behind all of this. You have people privately come to me in a red state and say, "The Clean Power Plan, we can handle it. We've got it figured out. We know what it's going to do to us. It's not going to be that costly, but publicly I can't say that." And so, as long as we're still in that kind of mode, nationwide, I think it's really hard to have a good conversation, especially when go back to the point I made earlier. You've got the President saying he wants to do everything he can in terms of infrastructure and other things to help natural gas, but he's going to put coalminers back to work--and what's that going to do to the nuclear plants when that happens? I'm not sure that there's the oxygen in Washington right now to have that kind of conversation, with everything else that's going on there.

I'd like to be optimistic. I mean, I'm a Cubs fan. I should be optimistic. [LAUGHTER] But I think that conversation got tougher when the Clean Power Plan goes away, rather than easier.

Question 2: I know Speaker 3's answer to this. I'm not going to allow him to answer, but in your presentation, you suggest that PJM's analysis shows 14 gigawatts of nuclear retirements, and basically PJM becomes a gas and renewable RTO. The two words I haven't heard in the last day and a half are "fuel diversity." And the question I have is, is it a good idea? I understand that the markets dictate, in PJM, what remains economic and what doesn't. But is there value to fuel diversity that we are missing as a society, and should we somehow make sure that nuclear and maybe even some coal remain part of the mix to take care of any possible contingencies in gas prices further down the road? Because, once we close those nuclear units and those coal units, we're

not going to get them back. I'd like to hear what the other panelists have to say about that.

Respondent 1: Fuel diversity is not an issue. In fact, the PJM Report that just came out about this says that we can see this go away and, yeah, there's a resiliency issue in how we operate the system that maybe we have to work through, there's a need to worry about gas pipeline constraints, but, basically, it's not an issue. It's not a problem in terms of reliability.

Let me clarify that with respect to the PJM Report and the low gas price case that I presented in my slides, only in one of those low gas price cases did we see the nuclear retirements. Actually, in the other low gas price case, no nuclear goes away, and that's because there's a look over a longer horizon. And so, the question becomes, is it the case, with the nuclear units that we're talking about today with ZECs, are they at the right hand side of the distribution, such that they're really the most expensive units out there that are looking for support? Or is it that all of the nuclear units are in trouble? And I don't get the sense that all nuclear units are in trouble at all. It just seems to be the ones that are more expensive to operate. Why they're more expensive--you'll have to ask the owners. I have my own theories on this. I think it's pretty clear what happened in Wisconsin with Kewaunee. There was a lot work that had to be done on the way the contract was written, the way Wisconsin Utility was on the hook for it. They said, it's cheaper for me to build combined cycle gas, bye bye. That was a pure economic decision. Easy to do.

Respondent 2: I would importantly differentiate between existing plants and new plants. I think there is more of an argument for maintaining existing generation sources and particular nuclear resources for this reason than there is for building new ones, for the simple reason that was mentioned today. For either a new nuclear plant or a new coal fired power plant, the economics are over decades. And it's hard for

me to see how the fuel diversity argument trumps the evolution of the electricity system over the next two, three, four decades. So, at the very least, I would be much more cautious in using that argument to support additional investment in new generating facilities.

I think it's a lot more interesting to think about the existing facilities. There's uncertainty about how quickly, for example, the cost of renewables will come down, and how quickly the cost of complementary technologies we need to integrate renewables at higher levels of penetration will come down. So, while my natural inclination, as you might have guessed, would be that we should do this relatively quickly, I think having the existing facilities as a backstop for a while... In the case of coal plants, they don't necessarily have to produce a lot of electricity. They just could be there, not running much, but running more if there's a problem. The European natural gas-fired plants are all basically playing that rule. Low capacity factors, but the system operators think it's good to have them around for a while, until there's more certainty about whether the cost and the technologies to do the integration or to make a system at high levels of renewables work at comparable prices to the current system. So, in that context I could see the existing facilities more as an insurance policy.

The nukes and the coal plants have different problems. The coal plants obviously have the emissions issue. The nukes have the problem that they actually make the renewable integration harder, in some states. They have much less operational flexibility than what they might be replaced with. And so, in some sense, if the nukes retire, you get a bump to emissions, but assuming you replace them with gas, you're actually increasing the flexibility in the system a fair amount. So that's a different kind of positive tool that you add to the system as you remove the fuel diversity.

Respondent 3: I was just going to make exactly the point that was just made. I think fuel diversity is obviously valuable. Anybody who tells you they can predict the future price of natural gas is ignoring a long and storied history in the United States. However, certainly the challenge, especially with the nuclear units, but also with the coal units, is the emerging need for flexibility in a renewables-rich system. And part of the issue with those units is cost and competing on price. But part of it also is just the change in the operational pattern, and what we're seeing in the CAISO is just that it's a really different world and it makes it particularly challenging to deal with the integration problem. Now, maybe the view is that we shouldn't get to that level, and California is crazy, and I'm not going to prejudge that view in either direction, but I would say, if you do go to that world, then it makes it much harder to integrate those kinds of units.

Respondent 4: I think a lot of people, including a lot of commissioners, around the country would think that diversity makes sense, but there are short term and long term cost considerations, especially in the vertically integrated states, where generation is part of their decision making process. And one consideration is that gas is cheaper now. There's always the pressure to have cheaper costs on the system. But, long term, what are you doing by having this gas build out? Are you setting yourself up for problems in the future if prices change? One of the interesting things in the context of Clean Power Plan, or whatever carbon regulations might be at some point, if you really believe the numbers of where you have to get to in terms of carbon reductions, to hit international goals, we're going to have a huge gas problem in the country in just a few years, that we've got to try to figure out through carbon capture or some other kind of technology, because while gas, now, as it displaces coal, drives all the emissions rates down, at a point where you have to do more, that means you'll have to do something more with gas too. And I don't know how much

that actually gets factored into lots of the decision making issues. So, there are lots of considerations, obviously, with respect to fuel diversity.

Question 3: One of the problems I see is political. How do you deal with the fact that you've got the ZEC argument on the table all over the place? You have the arguments the renewables people are making. If gas becomes a problem, you can see the argument that will come out about flexibility. So, how do we avoid this becoming simply an all-out clash between interest groups, and come up with coherent policy? That's one of the frustrations. And if you listen to the discussion of the panel, it kind of illustrates the problem, not necessarily that anybody on the panel represents any particular interest group, but just sort of presenting the issue. That's what I see as happening. Jockeying for favorable treatment by various interest groups.

Respondent 1: You're probably right, but what I fear the most is this. Interest groups say that we've got to have renewables OK. So we're going to have more policies like renewable portfolio standards. Now, we've got to keep existing nuclear resources, so we're going to have ZECs in place. So now we've got a payment for that, and now we've got to worry about jobs for the coal units. And so now we're going to have Dirty Energy Credits or some sort of out of market payment to keep those resources alive, under the guise of economic development and so on. And pretty soon we no longer really have a market. Now we have pay as bid that almost looks like cost of service regulation.

If you look at the Illinois legislation, for example, and you look at the social cost of carbon that they're using, \$16.50 per megawatt hours is the imputed social cost of carbon. And if you look at the baseline price, which is about \$31 a megawatt hour, that they're using, and you look at what that implies about the nuclear units

in question, that comes out to \$47 a megawatt hour in 2017. But, yet, I look at the cost of operating a nuclear unit from NEI, and the average cost for multi-unit facilities is \$33 a megawatt hour. That's beyond cost plus by 10 percent at this point. And so I see that, and we look at renewables. I keep hearing from the renewables people, "We're in the money. We don't need the subsidies." OK, then why do you want the PTC and ITC? Well, they say, because it really helps us with our cash flows or whatever. At this point it's actually gotten to be rent seeking behavior.

And so it goes back to that cost of service world, and even beyond that now. And pretty soon, none of the offers that come into the energy market make any sense, except for maybe a gas unit, that doesn't have that extra support. That's going to mess with price formation in the energy market. It's going to hamper operations if units don't want to back down, especially renewables. It's not a world I want to be in. But, yes, that's what I fear.

Respondent 2: In the absence of a federal approach, national discussions matter less. So, while I agree completely that there is a lot of rent seeking, the kind of the extreme positions that you outline I see more nationally, not at the state level. I don't think there's a big discussion about maintaining fuel diversity by building coal plants in California or in New England. The nuclear discussion is similarly coming to an end. That doesn't mean that there aren't still factions that are involved in the rent seeking piece. But I think in some of these more optimistic states, the discussion is a little bit more centered around solutions. So there's a little more agreement about a set of options, and then there is a lot of disagreement about which ones to emphasize a little bit more and which ones to emphasize a little less. But I think the discussion is a little narrower than what is reflected in these extremes that you see when you look at all the national discussion.

Respondent 3: Different states care about different things, and their priorities are different. So, if you're in Minnesota, for example, I mentioned the CapEx decision that the PUC's going to have to make with respect to a couple of nuclear plants that are set to close in the 2030's, but might need a billion dollars in CapEx just to get them to that point. So you're going to have the discussion about whether they try to extend their license and whether that's worth it, or do we spend our money somewhere else? But clearly Minnesota's a state, at least traditionally, that cared about the greenhouse gas emissions levels. They have state policy, they tried to work toward it. Losing those two plants pretty much wipes out all of the gains that they made. They've got some coal retirements, too, but in terms of renewables and efficiency policy and other stuff, losing the nuclear plants pretty much wipes that out.

I'm not sure we can tell Minnesota whether they can or can't care about that. If you had a Federal policy, they'd have to comply with it. My point is that that's going to be part of their decision making process, just like in Connecticut. If Millstone closes that's a huge part of the non-GHG emitting generation, not just in Connecticut, but in New England ISO. So that becomes part of that discussion.

And the other part is, we've been operating under this for a long time. You've got a lot of states that have RPSes. A lot of states that have EEPs. Illinois has a Clean Coal Portfolio Standard. We had people in Illinois once that came to us every year, wanting to get burning tires as a renewable resource. So, every state's been dealing with different pieces of this, and the RTOs have been having to deal with all the different considerations there. So, I don't know that it's a change, necessarily, in that construct. It may be a difference in degree, and there will be changes, because all the markets are changing. But I don't know that it's all that different from where we've been in the absence

of Federal policy for the last 20 years. I'm not sure.

Respondent 4: I'll just add that the discussion should get close to what actually goes on when you want to develop something like a Clean Power Plan or a state cap and trade or another state carbon pricing policy. The same sorts of interest groups are at the table, and they're asking for the same sorts of things. They might ask in different ways. It might have different effects on the efficiency of the overall program. It's much better to have a food fight over an allowance allocation than over a subsidy policy. But the same types of interest groups come to the table. Ask anyone who was at OMB during the Clean Power Plan development process, and ask yourself why, when you look at the spreadsheet for the building blocks, is it so darn complicated to figure out what EPA did? For the same reason there are nuclear subsidies in Illinois.

Question 4: One of the speakers illustrated that we're likely to reach clean power plant targets by 2030 just via gas build out. And taking into account the fact that, for one, Clean Power Plan targets are not actually where we need to be as a world to get to our emissions goals, and then, two, that if we meet our goals entirely with gas, then we have this big problem in 2030, do we just cross our fingers and hope that gas prices have gone up a lot by then, and that will drive the further carbon reductions? What is the alternative to having things like RECs to push that further, if you have this market environment and a FERC decision to go after subsidies and invalidate them? Because the other thing is that the subsidies are happening on a state specific basis, and Connecticut certainly isn't supporting coal. So, it's a federal decision to either support subsidies or not, and then state decisions around what the subsidies are. I'm just curious what the thoughts long term are about that and what the market should look like.

Respondent 1: I'm going to echo something that Speaker 3 on yesterday's afternoon panel said. You're putting RECs on for renewables. If your goal here is for carbon dioxide reduction from the sector, you're not actually addressing the externality directly. You're doing it in an oblique fashion. You're doing it in a way that's actually reducing electricity prices, which is sending the wrong price signal to consumers, who are now going to want, all things being equal, to consume more, not less. It erodes the value of energy efficiency investments. And so it's going in the wrong direction.

That effectively this goes back to the point that our earlier questioner was making, and why he's hopeful--just put a price on emissions. Address the externality directly. And it solves a lot of the problems. The issue is, in this political environment, is that going to happen? And I just don't have a lot of hope for that right now. Except for the fact that the current administration, in just over two months, seems to already be imploding to the point that maybe in 2018 we could have that conversation. But at this stage, I just don't see how that happens. Even with the proposal that was brought out by the luminaries and those with experience in the Republican Party (James Baker et al.) to have a carbon tax. I just don't see how this administration listens to that logic.

Questioner: I agree, and that's why I'm wondering, is it then at that point a productive move to tax subsidies at a FERC level?

Respondent 2: I think what we're saying here is that the economics of the power sector support decarbonization. But there are a lot of other sectors that have to decarbonize that are not decarbonizing, really, at all. If anything, they're going in the other direction, and I think that is where we really need to be doing the hard work right now. And those are politically harder, because they're closer to consumers in terms of the choices that have to get made, but, for instance, I would love to see much larger

subsidies for electric vehicle deployment, maybe tied in some way to the electric power sector.

To me the fight over waivers is the right place to stand and fight for a climate policy in the United States right now. Not the trade that was made in Illinois to get certain things for renewables in exchange for a set of policies for other types of facilities. That was kind of the deal that was struck by the environmental community. But that's just my personal opinion, and I understand the concern about what happens when we get to 2030 and we have a lot of gas units? I think the real answer is, they become stranded. That's the true answer. We're looking at a serious stranded asset problem, and everybody needs to be aware of that. And certainly the folks that are thinking about private finance of new and natural gas fired capacity in California are worrying about that a lot.

I think that's part of the reason that the kinds of plants to build are small units that are less capital-intensive and more fuel-intensive. So, you're shifting. Just like in the developing world, you build a gas plant instead of a coal plant, where there's very high regulatory risks. I think the same kind of thinking and decision making are going to happen in the power sector, and that will make it, not easy, but easier to figure out how to allocate the losses when they occur eventually, when there is eventual power sector regulation. And, in the meantime, I just think we really need to just be making progress on the other sectors, because I'm very concerned about those.

Respondent 3: In the absence of the CPP or federal action, and with insufficient RPS to meet the long term goals (as I said, in a bunch of states, they're not just goals, they're mandates, basically), I think you're beginning to see action. What California's doing currently is certainly implementing a law that requires those long term reductions in economy-wide emissions with a pretty aggressive program. A recent decision by the Massachusetts State Supreme Court basically

told the Executive Branch that it had to come up with policies to meet the goals that are on the books. In those states, there is action.

I tend to be a little less purist about the carbon pricing, because I think there are other market failures that carbon pricing doesn't address directly. I think that the case is now weaker for things like solar support or wind support and sort of the innovation market failure. That should be cured by now, given the state of development of those industries.

California is pursuing relatively aggressive greenhouse gas emissions reductions through 2030. It is much less clear whether they could achieve those if those goals were ultimately implemented through a carbon pricing scheme, because it would turn out that the carbon price required for the marginal emissions reductions is probably above the tolerable level, even for a state like California. At least there are indicators of that. If you look at the implied cost per ton of the existing programs that are not in the cap and trade program, like the RPS, you can get hundreds of dollars per ton removed. And we can have a long discussion of whether, in that case, we should just not do those things, but social cost of carbon or not, the California law says, "Thou shalt reduce." With a pure carbon price, you would get some kind of evolution, I suspect. The only other way you're going to meet the goal is by sort of "hiding the ball," which I think is what Thomas Friedman calls this.

So, as a political economy story, I think the answer is not just a single carbon price. It's going to be a set of things, and, particularly on the transportation side, it's hard for me to see how a pure carbon price will incentivize the kind of massive infrastructure investments that will be required to switch to a very different transportation system. There will have to be some complimentary efforts, and to California's credit, with all the messiness and expense, at least there's a thought process about the kinds of

activities that you might have to engage in to facilitate that transformation.

Respondent 4: I just have to respond to something you just said here that really struck me. There's a lesson from history here. I can take any of these policies and I can drive the CO2 price, the marginal cost of abatement, to zero by investing in discrete technologies that will reduce emissions. The history example that I will use has to do with how, under the Clean Air Act, Title 4, with the Sulphur Dioxide Trading Program, the original estimate of the marginal cost of abatement was in the hundreds of dollars per ton of SO2 emissions (sulfur dioxide emissions). What happened was, we had a lot of really bad economic decisions that saw scrubbers installed on more units than would have been economic or necessary, and they got rate-based in most cases, because this is pre-RTO markets and wholesale restructuring, even though the 1992 Energy Policy Act was in effect. And these decisions were made, but what that eventually did is drove the allowance price down into the basement. But it actually made the cost of meeting the program goals that much more expensive. So, I think it's really misleading to say that a high CO2 price is going to lead to a higher program cost. It's just simply not true. And history bears that out.

Respondent 3: That's not what I said. I didn't say it leads to a higher program cost. It leads to a higher carbon price that's politically not digestible. It's a very big difference. And so that is the difference. The SO2 program is a small program compared to a CO2 program. The redistribution effects that you get from having a carbon price of 100 bucks are significant.

The debate around Waxman-Markey and the fight over the allowance allocation shows how difficult the battles are. Even if you could agree on a carbon price that high being acceptable, there would be a huge food fight over how that gets distributed. So, I did not mean to say at all that you get a better program outcome in terms

of cost effectiveness by going around the carbon pricing. I'm saying it may be the only way you get there, given the political realities of what can be digested.

Among the non-carbon options there are better and worse ones. There are some where you do provide specific technology support. I think there is a limited role for those, for infant industry, R&D support sometimes. But the RPS, while clearly limiting the sources of emissions reductions to just the eligible technologies, it's not a direct command and control approach. There is a market mechanism that operates within the RPS. So, there are degrees of making this worse, from your perspective, in terms of being less efficient. And I think, at this point, with an RPS, there are a number of technologies that can compete, and they should compete. So if RPS works better than a carbon price of \$325 a ton, then I think it's just a political reality that we may have to have an RPS as part of the solution.

Question 5: The question raised earlier got me thinking about California, and I've done a lot of work there, kind of following the cap and trade program. And in California, you have cap and trade, you have a low carbon fuel standard, you have a renewable portfolio standard. We have solar subsidies. If you look at the list of climate policies, it goes over to two pages. And our hope is that when 2020 comes, Jerry Brown has a chance to pivot one way or the other. He has a chance to go ahead and kind of say, "OK, carbon pricing is working. We've gotten a lot of accolades for this. The market is effective, even if the prices are kind of down at the floor. The mechanism is working, and we're kind of confident in that."

But there's a chance to pivot, in the sense that you could start to dial back the renewable portfolio standard, the low carbon fuel standard, all these other programs, and put more emphasis on the carbon tax. People would be used to it, even though energy taxes and Americans are kind of two things that don't go well together--

it's like oil and water. And people need to get acclimated to this in some way. They need to get desensitized to this.

The other option would be that you could kind of double down and say, "OK, we're just going to keep blasting ahead with RPS and with more stringent low carbon fuel standards. We're going ask the fuel industry to reduce the amount of nonrenewable fuels by 50 percent compared to where they were," which is one of the proposals.

And they took the latter approach, which I saw as really kind of unfortunate, because there was an opportunity for California to see if it could break this gridlock on carbon taxes not working and being seen as politically unacceptable, and instead kind of double down. And that was an unfortunate lost moment of opportunity for California, whose greatest impact, arguably, is in showing what is possible to the rest of the states and the rest of the country, rather than necessarily the impact of their economy on the global problem, which it ain't solving on its own.

Give people's experience elsewhere, is this kind of a similar problem we're seeing? In Massachusetts, we can drive up RGGI, and I realize the states are taking steps to try and ratchet down on the cap to get the price up. But nonetheless, the believers, Connecticut, Massachusetts, Rhode Island, are kind of pushing other programs at the expense of cap and trade. And the problem is that when you try to do both things at once, the other programs basically have the effect of depressing the carbon price. So these two programs work at odds with one another. They don't coexist very well, or at least they prevent the cap and trade program from doing what it's supposed to be doing. So I'm wondering, based upon other experiences, if you folks are also observing that there's not a willingness to let the prices grow at all, or whether there's some glimmer of hope out there.

Respondent 1: At the risk of offending anyone from California or the East Coast, working with a lot of states in the middle part of the country, they tend not to see anything that happens there as something that they want to base their own policy on. There were states in the Midwest, ours being one of them, that were looking at carbon reduction programs and other things back in the last decade. Minnesota's another one. There were others.

Why not just join RGGI? RGGI was willing to have other partners in there. The idea was kind of a nonstarter. The Midwest states thought, we can figure this out on our own.

The other part of it is, you look at the difference in prices in the Midwest versus California or versus the Northeast. And it really does change the focus, in terms of how these states look at all of the energy issues that are there. They may be willing to do something with respect to renewables or energy efficiency, but there's a cap on it. There's a strict dollar limit there, because low energy prices are an economic development tool in a lot of the Midwest. They see it as that. Whether that's true or not, that's the way that it's seen. It's one more arrow in the quiver for governors to be able to go out and say, "Come to our state."

It happened in Illinois, where we used to have the highest electric prices, and after deregulation and municipal aggregation and low gas prices, we ended up with some of the lowest electric prices in the Midwest. That makes a difference for the policy makers. And so, if you're Hawaii, and you're already sitting up here with your prices, that's a very different construct than if you're Indiana and you're down here. And so, I think you have to just consider the different lenses through which this is viewed. The states I work with see themselves very differently than what's going on on the coasts.

Respondent 2: I agree that it would be nice to give carbon pricing a chance. In some sense,

what California does now is a little worse than what you described. They're continuing with a bunch of measures which may or may not make sense. But then, rather than estimating the role of cap and trade, they're kind of postulating the cap and trade at a pretty narrow price range that will bridge the gap that may be left after the other measures are implemented. It's just not clear how that's going to happen.

One of the downsides of these direct measures is that you actually don't have the price signal for consumption. Rather than prices going up, prices go down, and then California, of course, incentivizes a lot of efficiency as sort of a direct measure, instead of incentivizing it through higher prices.

Being from Germany, originally, where retail rates are somewhere in the 30 to 40 cent range and a four person household's average annual consumption is 3,500 kilowatt hours, with a climate that's worse than California for this kind of thing. I can see the long term benefit of having higher prices that reflect the externality.

I come back to my earlier argument. Given the way policy and politics work in the United States, it's not clear to me how you get there. If Governor Brown goes out and says, "All right, this is what we're going to do. We're going to double your electricity rate, but we're going to refund the stuff some other way, and you're going to not double your energy bill, because there are all these wonderful energy efficiency things you can do," I suspect that's the end of that political career.

So I completely agree with that. We've got to find a way, but the question is, how do you get to the long run without completely losing the battle in the short run, as you're trying to do this? I'm not sure.

Respondent 3: I would just say that it ain't over in California, and I think the story that CARB tells in its scoping plan documents is not terribly

fact-based. [LAUGHTER] And, to be gentle, and not to compare them to someone else across the country, there's a lot of optimistic thinking in that document, especially about the performance of the regulatory measures. And what that means is, the cap and trade market is going to actually do a lot more than is reflected in those documents. And the real challenge for California after 2020 (and it's a challenge no one has confronted) is how high a carbon price is politically sustainable, and how do you create mechanisms within your market design to sustain as high as price as possible?

I think there are questions there for households, and there are also really big questions for industry. Because the whole system of protections for energy-intensive trade-exposed industry in California are via a free allocation right now. And that whole system is kind of dreamed up, basically, with the idea that carbon prices are between zero and \$10 per ton. There's an analysis by Meredith Fowlie and Mar Reguant that has underpins that work. And you talk to Professor Fowlie and she'll say, "Oh, don't trust it beyond maybe 10, 15 bucks a ton." And we're going to go way past that under the current market design, at which point there's a question called about how you protect firms as well. And those conversations aren't happening right now within the CARB, but I can tell you they're definitely part of the legislative conversation.

Respondent 4: Respondent 3, you talked about what the average electricity consumption is in Germany. The same is true in California. The kilowatt hour consumption per household in California, where electricity rates are high, pales in comparison to what it is in, say, the Midwest, where the standard bill is a thousand kilowatt hours as sort of the benchmark. So there, you're talking about something that's four times what you're looking at in Germany. So, rate is one thing, but it's about total expenditures, and how does one deal with that.

But something that hasn't been discussed very much here is the whole idea of revenue recycling, which is that if we had a tax on carbon (say, the social cost of carbon), that allows us to raise revenue, which then can go to offset other taxes and could also fund direct transfers to people who are impacted. So that, on net, certain groups that there's a desire to protect, or industries, can be protected. This is an idea that no one's really even talked about very much, except for when we got into some of the issues with the Trade Ready Program under the Clean Power Plan, and we talked to some of the states privately, and they would get into the issue about the allocation food fight. Well, the allocation is just a pot of money, and it's just a transfer. You can allocate those funds to whomever you want to. It's not going to change the price formation in that market. But it's interesting that we haven't really even gotten into the possibility of actually reducing other tax burdens and transfers.

Respondent 2: I'll just make one quick additional point about California. You may not know it, but right now you could argue that California has a revenue-neutral carbon tax as a policy in effect. The carbon price is at the floor. So it's a carbon tax. And, essentially, all the allowances that are sold at auction are rebated on bill to utility rate payers. So the utilities get the allowances. They sell them. They have to take all that money and give it back on the bill as a credit to their customers. And so its approaches a revenue-neutral carbon tax policy. Not by design, but in effect.

Respondent 2: Just to be clear about the difficulty, a lot of the differences between the per capita electricity consumption in Germany and the Midwest or even California are due to extremely long-term investments and societal decisions that were made. And so, as far as incentivizing that kind of change through a carbon price, I like it. But it's just very hard. For example, encouraging people to move into 700

square foot apartments as opposed to 2,000 square foot apartments. [LAUGHTER]

The other thing I was going to say is that saying well that we could redistribute the gains from a carbon tax is a completely useless argument, since, empirically, the second half of the bargain very rarely gets implemented. And I think that has manifested itself quite clearly in the last election. It's not enough to say, "This is more efficient." At the very least one has to credibly demonstrate how a more efficient system would implement the second half of the revenue recycling to the people who would otherwise be most affected.

Question 6: Energy efficiency has been mentioned once, but it seemingly could have been a very important part of the CPP. If there is no CPP, what happens to the state programs and also appliance standards? Because LED lighting actually avoids more power production than rooftop solar. It's not very exciting, so we don't talk about it the way we talk about rooftop solar.

Respondent 1: I think that in the demand growth numbers, you're exactly seeing that kind of energy efficiency. I would call that, for lack of a better term, passive energy efficiency. It's the energy efficiency built into the building standards that apply, and standards that have been changing over time and have been continually updated and ratcheted downward so that we have become more efficient in our electricity usage. And so I think that is embedded in the trends that we've seen in the last decade.

Now, how much of that is driving the trends we've seen in the last decade? I have no idea. I wish I could say. But you're now starting to see this. At least in the PJM load forecast, the most updated one, in 2017, accounts for that kind of energy efficiency improvement in both the building and appliance capital stock. And it's actually a really important factor driving a lot of this. So, if we actually redid the CPP study, if I

went back to PJM and said, "Let's run it with the 2017 load forecast," CPP would be even less binding than what I showed here today.

Respondent 2: Of course it's funny not to mention building or appliance standards. It's just the thing that worked on the energy efficiency side. Those aren't exactly market mechanisms. It turns out they actually work reasonably well. That's one of the things that got dissed in the budget proposal, I think. So, I guess, on the positive side, if you believe (and I think it's really a religious issue, in some sense) that energy efficiency is indeed as super cost-effective as people do believe, than I think that in the absence of the CPP there will be continued pretty serious efforts to support energy efficiency without a price signal.

You definitely see that in California. You definitely see that in Massachusetts. And so I'm a little less worried. If anything, I think the CPP models could have underestimated the impact of the existing programs on future energy efficiency efforts and perhaps even results. So I'm a little less worried about those going away, just because there's such a big constituency of people who think that is the most important thing we should do.

Question 7: I'm going to try to end this with a little bit of an optimistic point and ask for your opinions. So far, rate payers have committed to about 10 billion dollars over the next decade in direct subsidies to nuclear. I was very struck with something that was said about how nuclear may not be the right technology in terms of load following, if we think renewables are going to be coming an increasing part of the supply stack. Load growth is going down. Maybe you don't want big baseload inflexible units on the system, which is kind of an interesting idea, and I think that's the conclusion that came in the Diablo Canyon case, which made a lot of sense.

So, my sort of challenge to you is, if I gave you 10 billion dollars over the next decade to invest

in a way that you thought would be extremely effective in fighting climate change, would you give it to the nukes? Would you build 20 thousand megawatt hours of battery storage? Would you put it into energy efficiency? Would you build a thousand megawatts of renewables a year? For all these, the math roughly works out. What would you do? I'm going to posit that you cannot put in a straight up carbon tax, both because I think it would blow the budget, and because it's just too easy.

Respondent 1: I'd take the money and use it to try to change vehicle fuel efficiency, whether through EV deployment or some other program, although I don't love the idea of just giving cash grants to people who buy Teslas. I think there's a better policy design option than that, speaking as someone who comes from a neighborhood where it's like every other car is a Tesla, it seems like. If I had 10 billion dollars, I honestly wouldn't spend it in the power sector.

Respondent 2: That's a great question. I'd do a couple of things with the money. One thing I would do is put a lot of it into R&D and different technology in the power sector and see what's promising. Is that storage? Is that carbon capture technology? Is that advanced nuclear? I'd see what bubbles up to the top as being really promising. I think I would do that.

If I was going to invest some in programs now, I would put a lot into certain efficiency programs like CHP. I think when we look at it in the Midwest, there's a huge amount of efficiency gains that can be done there, and I think you could structure programs such that that's something that would be really valuable, not only in terms of greenhouse gas reduction, but as an economic development tool for the industrial users who might make something out of that.

Respondent 3: I would say, since I can't say carbon tax, obviously it's carbon price.

I actually think, in some sense, the question is focusing on the wrong thing. I probably would be OK with giving that to the nukes, because, as I said earlier, focusing on new investment is really important. 10 billion dollars is a lot of money to you and me, but if you think about the next 25 years and the overall investment it will take to transform the energy system, not just the electricity system, but the energy system, we're going to make lots of 10 billion dollar mistakes, and so, if the 10 billion dollars are part of a program that helps build some kind of consensus toward lowering carbon emissions, I think I would be OK with that. That doesn't mean I think that's the best use of the money, necessarily, but I think it's just a relatively small piece of the overall puzzle and we shouldn't obsess over the small piece and forget the bigger challenges.

Respondent 4: Just to add on to that, the nuclear decisions, again, aren't necessarily getting made for greenhouse gas reasons. In Illinois, you could have very well had bills like I used to see when I was in the Legislature: "We're going to support X industry because X industry provides this many jobs, this much economic impact to our communities." You could have very well seen it like that, and separated it from the power sector discussion. It's not just about the GHG decision. So that's a whole different equation as to the value of it, too.

Question 8: I just want to follow up on the question I had originally asked. I heard a lot about California and a lot of the things you are doing in California, British Columbia and Alberta are also doing, and maybe we should be talking about control areas and having a control area together. So back to you on whether you think that's a brave new future, and whether a control area as a group maybe can deal with environmental policy better.

Respondent 1: I think there are two ways to answer your question. One answer has to do with jurisdictions cooperating on climate. And I

think that gets a little bit more complicated under a Trump administration. There are legal constraints on the U.S. side with respect to who has a foreign policy and who doesn't. When the state foreign policy is consistent with the federal foreign policy, it doesn't really matter, but when they're different, bad things can happen to state laws. So that concerns me with respect to carbon market linkage.

With respect to balancing area or control area cooperation on climate policy, I think that's the right way to go. The challenge that California has is that, for a long time, we made a decision to not build coal plants. Not in our state. [LAUGHTER] And so we built them in Utah and Nevada and on the res. And so the challenge is power moving across control area interties, and how to manage the carbon in that context.

An even more difficult challenge, though, is when you have part of a control area (especially in an organized wholesale market with unit commitment) under a carbon price and part of

the area not, or different parts of the area (which was the prospect in the WECC) under different carbon prices. When there are different carbon pricing regimes and different market designs, that is a mess. It is really complicated to manage. All the solutions are imperfect, and the higher the carbon price, the more the imperfections matter in terms of the functioning of the wholesale market and/or the reality of the carbon accounting. So, if there's a plan to coordinate across provinces on carbon pricing, if provinces can coordinate on electricity market design as well, that's a really good thing for the long run. And I think the same could be said in the other direction. If you have a common market, then there are strong reasons to look at trying to coordinate the development of whatever is done to comply with the federal mandate to have a \$50 price by 2022.