HARVARD ELECTRICITY POLICY GROUP

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Rapporteur's Summary*

Session One.
Better Markets, Better Products, Better Prices

The evolution of organized markets creates new tensions and reveals hidden problems. The Regional Transmission Organizations are actively involved with stakeholders in addressing these problems. New England has conducted a continuing series of workshops on spot pricing models. The MISO is moving forward toward its ELMP implementation to deal with lumpy dispatch. PJM has offered new capacity product rules and definitions motivated by reliability requirements. The concerns expressed by many cite a need for new product definitions to include the value of nuclear plants, demand response, distributed energy resources, fuel supply, fuel diversity, storage, and so on, not captured by the existing market designs. The search is for something new or different. Similar concerns are expressed and efforts are underway across the country. New York is "Reforming the Energy Vision" at the state level. The Federal Energy Regulatory Commission launched a series of price formation workshops based on a view that "there may be opportunities for RTOs/ISOs to improve the energy and ancillary service price formation process." How do these problems and proposed solutions interact? Poor prices undermine market performance. Is the path to improved performance found by defining new products or better prices? When are these alternative approaches in conflict? When would better prices and better products be complementary? How can the unintended consequences of fragmented reforms be avoided?

Moderator: Welcome, everyone. The topic is better markets, better products, better prices.

At the state and regional level, organized markets are feeling increased pressure to better define or incentivize their products. Stakeholders, consumers, regulators, and grid operators are responding to the pressure through rule making, tariff changes, contracts, penalties and lawsuits. The drivers will always include

PHONE 617-496-6760 **FAX** 617-495-1635
EMAIL *HEPG@ksg.harvard.edu*
79 John F. Kennedy Street, Box 84
Cambridge, Massachusetts 02138
www.hks.harvard.edu/hepg

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price and reliability, but the Polar Vortex, 111d, and cheap gas have changed the game. Some of the questions that this panel will be addressing include, do we need new products? Or will higher prices suffice? How do we track investment? Do we need incremental solutions or comprehensive change? And how do you balance price and reliability in any market reform?

Speaker 1.
Good morning. Let me just do a first disclaimer. All the views expressed by me here are my own, not necessarily those of the Commission. That said, sitting next to an esteemed commissioner here, I've got to remind myself of my obligation to consumers in the state as a regulator. It is, by statute, "safe and adequate service at just and reasonable rates." So I've got to start off with that all the time.

Most of you on the East Coast are well familiar with the impacts of Sandy in terms of both service to consumers, reliability, and prices. And then the Polar Vortex happened last winter, with enormous price spikes for many, many customers for a period of time. And there is the impending EPA regulation 111(d) that most of you are familiar with. So we looked at what was going on and said, "Should we continue business as usual for the next decade and beyond, or should we do something different?"

What is "business as usual?" When we look at, for example, the load factor in the state for the New York control area, what we see is a steadily declining load factor. That's your average load to peak load. We had 59% or so just a decade back. It dropped to just under 55% now. And it's projected to decline to close to 50% in a decade. So what does that mean? That means we are seeing increases in peak loads, but the energy growth is flat. And the peak load is growing at around 1% a year. The energy growth is pretty close to zero. So if we continue down this path, what would happen, all else equal, is that unit rates are going to go up for consumers. The system is designed to meet the peak loads, not only at the bulk power level, but even at the transmission and distribution levels. Some of the assets are designed to meet the peak loads.

So can we continue with increases in rates, particularly for a state like New York, that has one of the highest rates in the country? (We're not necessarily proud of that particular fact. But in New York, average residential consumer bills are the same as the national average residential consumer bills. That's the good news. And our industrial rates actually are more competitive than the national rates.) In any event, with declining load factors, we could see increased unit costs.

Second, when we look at the investments of our distribution utilities over the last decade, the investment has been about $17 billion in capital among the regulated utilities. And when we look at the next decade, we are looking at about $30 billion in capital investment--a significant increase in investments, predominantly to meet the needs of aging infrastructure. A lot of assets are old, 50 to 100 years old. There are some poles that are over 100 years old. And there are increasing demands from consumers for uninterrupted power supply, higher reliability. And so the increased capital investments would only translate to increased rates, all else equal, especially if energy growth is flat. It would mean even more increased unit rates.

Third, as I said, post-Sandy, the consumer demands have increased significantly, particularly from critical customers and others, for increased reliability. And many are looking at investing in assets for extra reliability, whether it be distributed generation or combined heat and power or some other resources. Particularly in a city like New York, we cannot afford to have ten days without power, or five days, let alone the two weeks that happened in Sandy.

And if you look at it from a fuel diversity perspective, our resource mix, fortunately, has been good in New York. Over 50% of our energy comes from non-emission resources at this time, nuclear and hydro, and the rest from mostly fossil fuel. That said, as we move forward, in the last decade, all the incremental additions in capacity have been natural gas (it's probably not surprising), and a little bit of wind, but mostly natural gas. And looking at the Polar Vortex and looking at our friends in the East, the more we depend on gas, the more price volatility, which is something that consumers are not ready for.

Just as an illustration, in the Polar Vortex, if we looked at those three months of January, February and March, 2014, compared to 2013, the unhedged energy cost to consumers was over $2 billion, just in the state. So, increased reliance on gas, particularly with the constrained gas capacity pipeline infrastructure, is ripe for potential higher prices. And then 111(d) is going to make the demand even worse.

So with that, we are looking at the question, should we just continue as usual? Or should we think of looking at a different path for the state? Hence, our new docket that we started this year, called REV, "Reforming the Energy Vision." After significant interaction with market participants and other stakeholders, staff finally issued a straw proposal a couple of months back with certain principles and recommendations for action. Comments are being collected now for commission action in the first quarter of 2015.

Some of the goals the commissioners articulated are not new. We want to increase the overall system efficiency, and thereby reduce the need for capital investments, unneeded investments particularly. We want to increase the reliability and resiliency of the system. We want to maintain affordability for consumers. We want to maintain or improve fuel diversity and reduce emissions, and, in the process, empower consumers to help manage their energy consumption and bills. And we'd like to do that as much as possible through animating the market, by getting new providers, new products, and new services to meet the consumer needs better.

So one of the avenues for moving forward could be a better focus on the demand side. I'm sure everybody here appreciates the value of improved participation of the demand side, which is generally silent in the wholesale market, not as active as the supply side. And some of it is because for our utilities, at least in New York and I believe in many other states, commodity costs are simply a pass through for the utilities, with no profit margins or penalties. So the amount of attention paid to managing commodity costs is questionable. And if you look at the load duration curve, you'll see, at least in New York, some quick facts. Our peak load is about 34,000 megawatts, but our average load is about 18-19,000 megawatts. And if you look at how many hours the load crosses 30,000 megawatts, it's less than 1% of the hours. But the reserve margin is based on the peak load. At this time we have a 17% reserve margin requirement. So you've got to maintain 17% more on top of the peak. It's right now slated to go up for next year. It's updated each year. So we are carrying an immense amount of resources to meet less than 1% of the hours above 30,000 megawatts.

So what can we do to address that problem? Based on a simple computation, if there's a magical way to address those top 80-90 hours, the savings could be enormous. If you just look at the avoided the capacity costs long term, the avoided certain peak hour energy costs and avoided T&D investments, one could be looking at over a billion dollars a year in savings. This is not being tapped today. That should be looked at.

As I mentioned before, the Polar Vortex, just for those three months, cost us $2 billion. There is an interesting, project that Con Edison has put forward (Con Edison is the utility that serves New York City and Westchester, and one of the biggest utilities in the country). They have a particular need in network to meet increased needs in 2017-19 timeframe, about 50 megawatts or so, ballpark. So their business-as-usual solution would have been, "We need better substations. We need better extra distribution." As far as the price, in a normal course, that would have had to increase to accommodate capital expenditures. When we challenged them, we asked, "Can you look at non-wires alternatives? Are there cheaper solutions? Are there better solutions to meet this particular resource need?" To their credit, they took on the challenge, and they've issued an RFI last month (and it got robust response now from all kinds of providers), and demand response, energy efficiency, CHP, anything you can think of, storage, solar, all kinds of resources responded. If there's a way those solutions can meet reliability needs, yet at a much lower cost to consumers, why not?

That requires a new thinking on the part of utilities. Their incentives today are essentially, for the most part, to put more into the rate base. You get a higher rate of return. That's as opposed to some of the op ex, which is just passed through. So can we find ways to incent them to look at different ways of doing things? That's a change for us, too, as regulators. How do we modify our thinking?

So one would probably say, "Why don't you just price properly and let the market take care of it?" Yes, we should do proper pricing. We are embarked on improving price signals to consumers. We have hourly pricing for the day ahead market, hourly pricing, location based marginal pricing for all our large customers. Almost 20% of our peak load is on so-called hourly pricing. And we have voluntary hourly pricing for everybody else--large customers, if they choose to. So anybody with about 250 kw and up demand is on hourly pricing, or will be on very soon. And it's default pricing. They still had the choice of going to competitors and getting whatever price certainty they want. But if they stay with the utility, that's a default pricing. And they also have capacity tags, which means that whatever their peak load was last year, that's what they'll be responsible for as contribution to the capacity cost. And we're also trying to move others to time of use rates, but we are limited by what we can do, based both on regulatory limitations and legislative limitations. We did start hourly time of use pricing, but we are prohibited from the legislature from moving forward with mandating time of use rates for essential customers. So we do have voluntary time of use rates. And we are also trying to move the capacity costs so we're collecting for them in fewer hours where the peak demand actually happens.

And so we are moving towards increasingly sophisticated pricing for consumers. That by itself may not be sufficient. Unfortunately, on the other side, the demand side, we are losing resources in the wholesale market. We had almost 1,800 megawatts of demand side participating in our capacity markets, which is down to 1,000 megawatts now in the last two or three years. We have virtually no subscription in day ahead demand energy markets, or in the demand side ancillary services products markets. So the participation of demand side has been less than stellar, and we need to find what the barriers are and what, if anything, can be done.

So what we are trying to do in this REV docket is put a bigger obligation or a challenge to our distribution utilities. "What can you do to encourage more demand side distributed energy resources to participate in the market to address some of the problems that I just talked about?" So, one of the constructs that is being considered (again, nothing has been finalized) is the creation of a so-called "distribution system platform provider," DSP. So the purpose of the DSP would be to see if there's a way to bring all the DR resources to play. Today, at the wholesale level, the ISO or the RTOs don't necessarily see things behind the meter. They stay at a bulk power level. But there are a lot of distributed energy resources that are out there, and that are going to increase in the coming years. So one question is, how best to take advantage of the DR resources that are there on their own volition? Or is there room to bring on more DR resources that would be even cheaper to consumers than the traditional investments that are being made, because of regulatory pricing signals that we provide today to the utilities?

So the DSP concept is something that we floated in our straw proposal, asking things like, how would the DSP function? What would its roles be, in terms of planning, in terms of operations, and in terms of market making? And how does the DSP interact with the wholesale market? In the first instance, should the DSP be the incumbent distribution utility? Or should the DSP be an independent entity? The traditional thinking would be, all the RTOs and ISOs are independent. They don't own assets, the underlying and generation, so the DSP should be an independent entity to avoid market power issues. So that's good logic. But are there other issues that would argue differently? That's an open question in our docket. Should distribution, DSP, be assigned to the incumbent distribution utility? Or should it be an independent entity? You have six utilities. Should there be six DSPs, or one statewide DSP? Or if the incumbent utility is given the responsibility to be the DSP, should market functions be separated out from that and given to an independent entity, but planning and operations stay with the incumbent utility? So those are some of the open questions on DSP.

The second issue I'll just tee up, and we can talk about it later, is the DR assets that we'll be increasing in the future. Should the incumbent utility or the DSP be allowed to own any of those assets? Should the utility affiliate be allowed to own any of the assets? And, if so, what should be the conditions? What are the market power concerns that come up with such arrangements?

So those are the types of fundamental questions that we are addressing in this REV docket. And, finally, the big thing is, everybody responds to incentives. So in the existing regulatory framework for distribution utilities, we have certain incentives in place, for example, in rate making. Everything is an incentive ,the way we do things, whether it's a regulatory lag, or reducing risk in the way we do rate making. So should that be modified in any way to affect utility behavior?

So those are the open questions. I'd be happy to discuss more and get thoughts from you folks in the next couple of hours. Thank you.

Speaker 2.
I'm happy to be here today to talk about something that we've been working on a lot in New England over the last couple of years, which is pricing. That sort of seems elemental. Shouldn't we be always working on pricing? Shouldn't we have gotten it all sorted out by now? And the answer is, yes, we should always be working on it and, no, we haven't gotten it sorted out yet, because it's actually quite complicated.

And I won't have time to go into all the reasons why it's complicated. But hopefully I can give you a sense of what we are struggling with in New England and how we've tackled the problem. And to give you what my punch line is, is, there are no easy answers, and there's no perfect answer to getting the prices right. There are probably better and worse answers, and sometimes that judgment is going to depend on where you sit. And that's something we are certainly finding out as we go through the stakeholder process, where, as you go around the table, people have very different ideas of what the right prices are and what prices ought to accomplish.

So I'll try to give you a sense of how ISO New England has broken this down and how we look at what the right prices might be and what we're trying to achieve with the pricing structures that we have in New England.

So why are we focusing especially heavily on pricing right now? I think most of you know the background in New England. Low gas prices have actually ironically created a problem in New England, because in the winter time, the oil units historically have not wanted to get fuel, because they didn't think they were going to run. But if they don't have fuel in their tanks, they can't fill up quickly. So they're not there when we need them. And because on 95% of the days, the pipeline capacity is adequate, the LNG providers don't see a business case for filling their tanks with very, very expensive LNG. So when our generators, on those 5% of really cold days, go to get LNG, there might not be enough there.

So at the ISO, we look at this and say, "Well, obviously we're not sending the right price signals, because we're not getting the reaction we want from the marketplace." So it's those real world drivers that have caused us to sort of ratchet up the intensity on improving the pricing in New England. And what we've done is we've really broken the pricing down into two distinct problems. One is, pricing during periods of shortages. That is, when we're short of energy and/or reserves, are we getting the right prices? And those of you who are familiar with these markets know that ISOs and RTOs have needed to rely on administratively set prices during periods of shortage, because we don't have real responsive demand to do that for us. So, in the absence of that, we have to come up with prices, and when the markets first started, the $1,000 bid cap was the default backstop price. I think we've gotten a lot smarter over the years, and have recognized that that's woefully insufficient, and New England has been taking steps to correct that. The biggest step we've taken is the most recent one, which is, believe it or not, changing our capacity market. And I'll go through the details of why changing our capacity market is, in my view, largely an exercise in setting the right real time prices, but that's clearly the structure we've designed, and I think it's the right structure. And I think it would be good to have a discussion about that. So that's one aspect of it. What prices do you have when you're short?

The other aspect is, OK, so during the vast majority of hours, you're not short. Are your prices right then? And in a sense, they're right, because the simple marginal cost sort of mathematics that you use to calculate prices in all the LMP markets is in effect in New England, and we're getting the incremental cost of electricity during all those hours. But what you're missing out on are the costs that are being compensated outside the market through uplift payments. And those can be quite important at times, especially, for example, when you have a contingency, and you need to call on peaking resources. So what we are focusing on now with our stakeholders and internally is, "OK, during the large majority of hours when you are not in shortage, how are the prices less than ideal now, and then how might you improve those prices?" Unfortunately, it's not as easy as, "Oh, well, now that we've got the time, we'll just go to the bookshelf and pull it off the shelf and come up with the right prices," because it's not really clear what the right prices are in those circumstances. And I'll get into a little bit of how we're looking at that and what incremental changes we're looking at making over the next few years.

So hopefully that gave you a sense of the two different aspects of the problem and why I'm going to talk a lot about capacity markets when we're here to talk about largely real time energy pricing.

Our capacity market was designed recognizing that, in theory, in tight conditions prices should rise to the value the consumers are willing to pay. In reality, LMPs don't get that high, as I mentioned earlier. So we have to figure out some way to set those price levels. And what we chose to do is set them through our capacity markets.

When we set out to reform our capacity market from what it was, which I think was a pretty ineffective design that rewarded resources more for just being there than for doing useful things, we looked at it and had some principles going into that discussion. First is, "Reward outputs (that is, power delivered), not inputs." I don't care what fuel you use. I don't care how you get it, as long as you have it when you need it, and you produce when I ask you to produce. And if you don't, then I'll go to somebody else, and you won't get paid during that time period. So that was first. Second is, "Redefine the performance measures for capacity resources," and this is where the connection to the energy market comes in. Instead of more traditional measures in capacity markets, like availability measures and things like that that were commonly used in New England and other places, what we said is, "We're going to measure your capacity market performance by whether or not you are providing energy and/or reserves when we have shortages in New England, shortages of either energy or of reserves. If you are providing during those times, then you're performing. And if you're not, you're not performing. And your compensation will be directly tied to whether you are performing during those times."

So I hope you can very quickly see that our capacity market is really now just an extension of the energy market, that the performance metric is entirely related to performance in the energy market. And one of the advantages of that is that it better aligns the financial incentives of resources with what the ISO needs when they're operating the system. So, the elements of the capacity market include a base payment that you get in a forward auction, and we run our auctions 3 ½ years in advance, and you get some agreed upon dollar amount. So let's say the upcoming auction clears at, for talking purpose, $10 a kilowatt month. Fine. Then the next element of the capacity market is a performance payment. And this can be positive or negative. Let's say we have one shortage event during a year. If you don't perform at all during that shortage event, you give up some of your capacity payment, or, in other words, we view you as not having earned that payment in advance for performing during a shortage condition. If you over perform, you actually make more money. So your capacity payment is directly tied to your performance during that shortage event.

How much is the performance payment? There's an administrative rate that we set that reflects the cost of meeting New England's reliability standards. So going into a year when you've taken on a capacity obligation, you may make an extra $5,000 per megawatt hour for every hour in which you over perform, or you may have to give back some of your advance payments for expected performance at the exact same rate. So all of a sudden, the capacity market is really just a forward contract, and we settle up in real time based on whether or not you deliver in the energy market in real time.

The other interesting thing is that you don't have to be a capacity resource to be eligible for these payments. So if I choose not to get a capacity payment, but I still perform in real time during a shortage condition, I will get that $5,000 for providing energy and/or reserves during this period of very tight system conditions. So all of a sudden you don't even need to be a capacity market player to realize these payouts, which sends, we believe, the right signals to everybody to perform when the ISO needs you to perform.

And as it says in the slide, this is resource neutral. There are no exceptions. So it doesn't matter if you're wind. It doesn't matter if you're solar. This is how you get compensated.

The nice thing is, this also solves one of the problems that the ISOs have been dealing with for a long time (a hugely controversial problem for which there's, frankly, no good administrative answer), which is, what's the capacity value of wind, solar, running river hydro, limited pondage hydro? Historically, control areas have developed complex administrative mechanisms to say, you know, "Your wind resource is worth 27% of nameplate value, based on some administrative measure." Under our new approach, your wind resource is worth exactly what it delivers when we need it to deliver, no more, no less. There's no ambiguity. I won't say there's not going to be any controversy, because there already has been, but it's at least quite clear what the expectation is. (And everybody's laughing because the amount of controversy has been remarkable.)

So what are the expected benefits of tying the capacity markets so directly to the energy market? First, we think we're going to get much more efficient resource evolution, that is, strong incentives for new capacity to be one of two things, either be low cost and online a lot, or be flexible, but it's OK to be expensive if you're flexible. So either be cheap or be flexible. Those are the two types of capacity that we think are going to do well. What's going to do less well in this market is expensive and inflexible. So if you're a 40 year old oil unit that burns expensive oil, needs a lot of emissions credits, has a high heat rate and has a 24 hour start time, you're not going to like this market as much as if you are a ten minute quick start resource, of if you're a nuclear unit that's online all the time. Honestly, that makes intuitive sense to me. You know, we've always sort of struggled with the idea of paying the same capacity rate to resources that are hugely valuable to the system, like a pump storage resource, as we do to an oil resource that has a 2% capacity factor, and if you have an unpredicted shortage, you can't get that resource online, yet the pump storage resource is at risk of penalties, because they're always available., but inevitably they're going to have some mechanical problem, and they're going to get dinged for that mechanical problem. This, I think, sort of neatly solves that issue, because we're holding everybody to the same standard, and we're not giving you credit just for saying, "Yep, I'm available, but just don't ask too much of me, because that might be a problem."

We think we're going to see operational related investments at existing resources to improve their performance. Arguably, we're already starting to see some of that in anticipation of this coming forward, with resources adding dual fuel capability, for example. And then, finally, we think we're going to get a more reliable power system using market incentives and a more efficient result.

So what's the alternative to what we proposed? And what we have sort of termed that, "Texas sized RCPFs." And RCPF (reserve constraint penalty factor) is New England jargon for the price that we pay when we're short of reserves, which is a very important number, because we're short of reserves far, far more than we're short of energy, and that's what really tends to set the price during shortage conditions.

There was an active debate within the ISO about whether we should down the capacity market path that we did. The capacity market path we took, as I've said, strongly connects the capacity market to the energy market. Alternatively, we debated whether we should go straight to the energy market and just say, "We're going to just set really high energy market prices?" And that's something we strongly considered, because the incentives in real time are going to be identical, in our view, or nearly identical. But we thought there were some longer-term reasons that that was probably less desirable. Some of them are political, and I'm not going to get into those here, because that's a whole other hour and a half. But the reason we didn't really go down that path is largely the high degree of volatility that would result. I'm very anxious to see how it works out in Texas. And, frankly, if it's going to work anywhere, it's going to work in Texas. Right? You know, they have one state ISO. They have a strong commitment to free markets, and a seeming willingness to live with short term price fluctuations as a result. And I hope it works out, and if it does, who knows, maybe we end up closer to that in the future. But I think our concern was that, in the short run, we would have trouble attracting investment without liquid forward markets in New England. We're worried about, frankly, LSEs and their ability to cope with the price volatility, and as I mentioned, we were concerned about the political fallout if we had exceedingly high prices for a short period of time. It seemed better to sort of levelize those using a capacity product.

So those are our capacity market efforts.

When it comes to improving real-time price formation, we're doing a whole bunch of things. First, we've added a whole other reserve product, if you will, that, when it binds, will send scarcity pricing signals. Second, we're implementing hourly offers this December, which will allow the offers that come in to the market to vary by hour, which will, again, have a big effect on pricing, especially on volatile gas days. Third, the FERC ordered us to increase our RCPFs to $1,000 and $1,500, which will also have a big effect. Fourth, we're fully integrating demand resources into our energy market, which will remove from the equation an operator based, unpriced action. So that will improve our pricing. And then, finally, we're undergoing a real-time pricing review and enhancement project, which is going to look at the details of how we set price under very certain circumstances when you have lumpiness in the dispatch or you have costs that are not included in the energy dispatch. So we think that's going to be very important.

We developed some principles for what we are looking for when we improve our real time pricing. We have three principles. One is efficiency. And this is, to us, in a lot of ways, the most important one, which is that dispatch on the offered prices, at least conceptually, you know, in the absence of market power, will result in an efficient dispatch. That is, you're not dispatching expensive resource when a cheap one's available, and the dispatch resources will actually want to operate at the prices that you set in the marketplace.

The second principle is, we want price transparency. We always think it's nice when you can figure out why we have the prices that we have. In the current world, it's quite easy. We can actually go into the software and say, "That resource set the price for that five minute interval in that area." There are some changes that we might make to pricing that actually make it much harder to tell why the price is what it is in a given interval.

And then the third principle is simplicity. Believe it or not, ISOs actually prefer simple solutions to complex ones. They're just hard to find, oftentimes. Electricity market pricing is inherently problematic. The root causes are really production constraints and nonconvexities and lumpiness. So you have economic minimums. You have minimum run times that cause you to run units that you don't want to run. Economic minimums cause you to run units at higher levels than are economic. And then you have startup costs that are not reflected in the incremental energy bids. All those things give people pause when they look at their pricing and say, "Sure, you're sending a price, but what about all these other costs that are getting paid through side payments? Shouldn't they be rolled into the pricing?" Ideally, yes. But when you dig into the math of it, it seems that there are no perfect pricing approaching to roll those in.

Given those three principles we looked at, you need to sort of flex those principles if you're going to start to include some of these other things in the incremental pricing and in a dispatch. And to that end, we've looked at a whole lot of different things. Two tiered pricing, convex hull pricing, ELMP, which MISO is using--and those discussions are still ongoing with our stakeholders. What we are looking at most immediately is improving our fast start pricing, which is, if we have a contingency, and we start a fast start resource, or a peaking resource, how do you improve the pricing under those conditions? The problem with those resources is that they're highly inflexible. They're very flexible in one sense, in that they can start quickly. But once you get them online, they're quite inflexible. And that undermines our pricing algorithms in the sense that they are looked at as just a lump of resource that's either on or off, and they are generally not eligible to set the clearing price without any further adjustments. Currently we have a system which incorporates some sort of flexibility in how those resources are viewed by the software, distinct from how they're dispatched. So what will happen is, when we first start them up, we will roll no load and startup costs into the price that those resources are allowed to set into the first few intervals, when they're being started. But then once they're fully online, that treatment goes away. One of the things we're looking at is extending that treatment throughout the minimum run time of the resource. Second, once those resources are fully online, and synchronized to the grid, because they're very inflexible, or may have no dispatch range, they're ineligible to set price. What we're looking at is a software change to cause the software to think the resource is actually flexible, and has some ability to set price, even though in the real world we would still dispatch them in accord with their supplied physical characteristics.

So that's sort of a whirlwind tour of what has literally been 500 slides with our stakeholders on real time pricing. And I'd be happy to get into it more, but hopefully this at least started the conversation about what the problems are, and why they are so hard to fix.

Question: You mentioned that you were moving the demand response from an operator action into the market. And, just to clarify, in doing that, are you saying that you're putting that into your security constrained economic dispatch? And, if so, is that done through a bid to buy? Or is that an offer to sell? I wasn't clear on that.

Speaker 2: What we are planning to do, once the whole "does FERC have jurisdiction over DR" mess gets sorted out a little better, is to integrate them directly into our dispatch as supply side resources, so they would submit an offer just like a generating resource, and we would dispatch them the same way. The difference would be, we would be calculating a baseline for the resource, and their dispatch would be downward adjustments relative to their calculated baseline.

Speaker 3.

Good morning everybody. I'd like to thank Bill for the opportunity and the invitation to come and speak on this panel, to talk about a lot of these issues. We do face a lot of the same issues that ISO New England does. But I'm going to take a slightly different point of view.

Let's think about history a little bit. Let's think about 1978 and PURPA. What do we have that looks like PURPA today? Renewable portfolio standards. PURPA with a smiley face, we'll call it. We got rid of the Public Utility Holding Companies Act. And now we're going back to the 1920s and the days of Samuel Insull, where we're seeing M&A activity on a scale that we haven't seen before. Funny how Chicago seems to be the center of that again. There are a whole lot of different things going on here. SMD (standard market design) cratered and has risen organically from the ashes to actually really come into effect. So it's useful to think about the history and to take wise counsel from our friend, George Santayana. If we don't remember history, we're probably going to repeat it, and we're probably not going to repeat the good things. It will probably be the really bad and stupid things that we've done in the past. We have a tendency to unlearn all the good lessons.

So the way I want to approach this is a little bit different. I want to approach this axiomatically. And there are three axioms I'm going to propose here. The first axiom of good market or mechanism design is, "Ask what you truly want from the market." What is it you truly want from these products? And I'm thinking about this in the terms of adequacy and capacity markets, because when we first designed these, the first thing that came up was, "Well, we have a missing money problem." OK. Are we going to make anybody do anything for the missing money? Is there going to be something tied to it? What is it we really want? Do we just want the nice shiny new unit sitting there on a pedestal? Or do we actually want it to run and produce energy when we need it? We want both. Well, I can't have one without the other. I can't have the energy without the unit, but I want the unit to actually produce something, rather than to be just a nice museum piece. So it's about performance. And that performance is really about one thing, energy. Everything comes back to energy at the end of the day.

So if we want to tie the missing money to something, we have to tie it to performance, to actually producing that energy. Now, that brings me to what happened this winter. And our situation's actually very different from New England. But there is a huge mythology building that this is about gas/electric coordination, and that this is about the inability to get natural gas. And the truth is, it's not. Look at the number of gas interruptions. They accounted for less than a quarter of the total units forced out on our peak morning on January 7th. We had a bunch of other gas units that couldn't start up, likely on their backup fuel, in many cases, because a lot of those units probably hadn't tried to start their CTs on backup fuel for a long time. So is that really a winter problem, a natural gas problem? Or was it just an owner issue?

The coal steam units were actually our largest segment of outages. And then we had a slice of nuclear, and we had a bunch of other units out. But really, this is about unit performance, on the whole. And the reason for that unit performance could be different. It could be about natural gas. The gas interruptions clearly are those units that decided they weren't going to buy what I'll call spot firm with commodity, from a marketer in real time, or the day of or the day before.

Or it could be the fact that unit owners just didn't do a very good job with their operation and maintenance costs, because it's not a secret, energy prices have been extremely low since the Great Recession ended, partly due to the shale gas plays, partly due to the low demand. People are trying to cut costs. And if you cut costs, and you don't put a lot into the maintenance, the units don't perform very well.

And of course, this wasn't just on January 7th. This was actually throughout the month of January, and there's a pattern here and a theme. We had it really cold the 5th, 6th and 7th of January. And it kind of moderated during the month. And then it got cold again at the end of January. Now, having gone to graduate school at Minnesota, we just called this a normal winter, [LAUGHTER] where the usual forecast is well below zero, one degree above death, and you go about two or three weeks where the high temperature is minus something. It was actually warmer than that, and so I'm kind of surprised at the unit outages, just intuitively, myself, having lived in that climate, although I am a Florida boy by nature.

So these unit outages have persisted, which raises a bunch of questions. So the question is, what do we have to do to incent better performance? I think a lot of the ideas that ISO New England has developed and come up with actually make a lot of sense, and they make a lot of sense for us as well. We're discovering the same problems. Now, our problems are different. We're not as gas heavy or gas dependent or fuel oil dependent as ISO New England, but at the end of the day, it's still the same problem economically, and probably requires similar economic mechanisms.

Now, I can't give you more detail, because, as you all know, we are going through a stakeholder process. I won't get into the ins and outs of the stakeholder process. I know a lot of people aren't happy with the accelerated nature of it. But we actually are in the process of developing another proposal that we're putting out, and so I don't want to get too far ahead of that. But to simply say that as things move forward with the feedback that we've gotten from stakeholders, things are looking at little bit more and more like the New England model than maybe had been originally envisioned in PJM.

So with that, let me move on to axiom number two. And that is, "Let price formation happen with minimal non-market intervention." And there are really two forms of non-market intervention that I have in mind here. One is in the form of price and offer caps. Now, I was on FERC's staff, working for Dick O'Neil, when we had the $1,000 offer cap. And people keep asking me, "Well, what was the rationale behind it?" My response is, there's something magical about four digits in front of the decimal point. Actually, there was also a mythology at the time that the California ISO would not accept offers beyond $999.99, which of course turned out to be false as well. But there's something magical. We've actually put an anchor so if prices get above that $1,000 mark, the hue and cry is enormous—"We're getting gouged!" or, "Something untoward is happening!" But if we don't allow prices to rise, there are reliability consequences to that. So we have to think about that.

Now, the other type of non-market intervention that I have in mind is a non-market intervention that all of our operators do. After the day ahead unit commitment, we all do reliability runs, in real time operation. We all commit CTs to meet conditions as we foresee them happening. We all do it. And we have to for reliability reasons. But is there a way to minimize that kind of non-market intervention so that we don't crash prices, and we don't end up with a whole lot of uplift?

So, again, the Polar Vortex is a great lesson in this. That red line on the chart, that's the $1,000 offer cap in PJM, which is held sacrosanct by many. And here are the projected offer prices at the current gas prices in the East, and the market East gas prices here at basically Transco zone six, zone five non-wiggle, Texas Eastern market area three. You can see on a lot of these days, even for a ten, or on one of those days, even for a 10,000 heat rate CT, which would be really efficient, they're over the offer cap. If you're talking about the other, older, CTs, we're way over the offer cap. So what do we tell a resource? You've got a $1,000 offer cap. I need you to run, but it's going to cost you $1,500 to run. What is that rational agent going to tell me?

Comment: No.

Speaker 3: Exactly. That's a problem. That's a reliability problem. So we basically had to say, "Look, we will find a way to try to go in front of FERC. We'll try to make people whole for the costs, but we just need the units to operate." That was not a good place for us to be. So you've got to let the price formation happen and take place.

Now, we also do know one thing. Reserve shortage pricing works. We did go into reserve shortage conditions on January 6th and 7th. We did see reserve shortage prices. We saw energy market prices rise accordingly. This does work, with one caveat, of course. And of course, when the FERC approved our shortage pricing mechanism, it said all demand response could offer at the maximum price, so we don't even go through the shortage pricing levels. If we go short, or if we call on emergency DR, even if we're not short reserves, we go to the maximum price, which doesn't give the market much of a signal. Now, we have filed to get that changed, but the fact is that with this headlong rush into demand as a supply resource (which is like saying, "black is white and night is day," because demand is demand, supply is supply. The two should not be confused), still, this actually does work. So we actually do let prices form here.

And what about uplift? This chart is an example of approximately three or four years of uplift. You see that big spike there? That's January. Now, is that operator intervention? Or is that something else? Probably something else.

Speaker Two mentioned inflexibility at the very end of his presentation. A lot of the inflexibilities that generating units have—must-run requirements, minimum run times, minimum down times, and so on… Effectively what happened, and I'll get into this a little bit more in a minute or two, is that we had a lot of gas units that basically ended up with take or pay gas deals. And they needed to buy gas over the weekend for a Tuesday morning ramp, which was still part of the Monday gas day. And so we ended up having to run a bunch of units out of merit order for three days just so that we had the resources available when we thought we needed them for the next real cold snap. That's a problem.

Now, if I actually look at the chart in more focus without January of this last year, you can actually see that one of the things that we've tried to do is minimize operator intervention. We started realizing, talking to our operators, that we were committing a bunch of units to maintain voltage on our west-to-east transfers that we didn't need. We were running a bunch of units for reactive power. We were running a bunch of units for black start capability, out of merit order. Why do we need to do all of this stuff? Let's try to minimize that. And since the since the winter, you can see the amount of uplift has come down tremendously, because we're trying to do a better job of not overcommitting resources to meet a lot of these issues. And it's so far been successful.

So if we're thinking about things like ELMP convex hull pricing, well, what's the driving force behind that? Non-convexities. What do you do? Minimize the impact of those non-convexities when we make choices about what runs. And that's what we're trying to do here.

So, finally, the third axiom is, "Be as simple as possible, but no simpler." And yes, indeed, we can make things a little bit more simple. One of these opportunities to simplify I mentioned with the gas electric issue. Why can't we align information and timing? Why is it that the gas industry evolved so differently in timing from the power industry? Why can't we get the timing straight? Why are we having holy wars over something that should be relatively straightforward? And neutrality of resources. Speaker 2 said this, but I'll say it a little bit more pithily. We are technology, age, resource, fuel, and size neutral, subject to reliability concerns. Why is it we need a special tranche for wind? Why do we need a special tranche for nuclear? Why do we need a special tranche for firm gas? Hey, if people say they can be there, let them prove they can be there.

And then, finally, let's put demand back on the demand side of the market. I mean, I think the FERC case actually provides that opportunity.

In terms of market timing, let me explain what happened in January. There are two issues at play here. One is just institutional timing of gas commodity markets. Gas traders in Houston on a Friday, they trade their gas. They usually do weekend deals through the Monday gas day. They go home for the weekend, and they're done. Electricity doesn't quite work that way. A lot of these gas units don't need gas for three days. They maybe need it for one day or part of one day. A lot of the gas guys (not all of them, but a lot of them) are saying, “I don’t know how to do that deal.” But I think we heard recently (at Commissioner Mueller’s technical conference, I believe it was a couple of weeks ago now) that really these deals can be done, for a price. You can get those gas deals for a single day or part of a day. It just is going to cost you more money. How do we get those trades done? But effectively what we have is market by Rolodex today. We don’t have a central clearing house to do this. I mean, hasn’t technology finally caught up with us at this point in time?

So there are both sides to blame here. And obviously this was the effect of that--where that uplift came from was really the last half of January, not the real Polar Vortex cold, but the last half of January. And here (on this chart) is the correlation between gas prices, not surprising, and that uplift.

In terms of putting demand back on the demand side of the market, we actually did a big filing at FERC, went through a specific technical conference on something called “price responsive demand,” where we were actually going to put demand back on the demand side of the capacity market, have demand be reflected as a demand bid in the energy market, similar to what ISO New England is doing. We got all that approved. It sits in the tariff. It has been totally unused up to this point. But yet, with the EPSA ruling, how is demand going to participate in the capacity market? Well, rather than being a supply resource that says, “I was going to buy five bananas today, but I’m not buying five bananas, so pay me for the five bananas,” which is kind of backward, just say, “I’m not going to be there. I’m not going to buy the bananas. I’m going to save the money and not buy the bananas today,” and just reflect that in the demand for capacity or the demand for energy. It’s very simple. And, my God, technology’s actually caught up with us.

The last thing I will leave you with, since there are two panels dealing with CO2 policy, is pricing CO2. Well, we already know what gas prices have done to carbon dioxide emissions. They’ve declined since 2005 in the PJM region anywhere from 15-18%. Nationwide, it’s about the same level. It’s probably going to continue going down. However, we have this funny little state by state thing with Section 111(d) that we’ll spend a lot of time talking about over the rest of today and part of the morning tomorrow. But think about this. State by state compliance, all right. And I’ve got these big RTO markets that go across state lines. Don’t we feel like we’re kind of going backward here, to some degree? So here’s the picture of increased trading with the expansion of the PJM market. But now think about this picture going back in reverse because of EPA. We’ve got states in our footprint who are trying to figure out what they want to do. And some states have told us, not just “No,” but “Never, no way, no how, hell no. We are not going to be part of a regional compliance plan. Not only that, we are not going to make transparent in any way, shape or form what the price of emissions will be.” So, effectively, there are a lot of people spilling a lot of modeling time and ink trying to reverse this, rather than going from two areas where you have very little flows, to having a one large regional dispatch that’s much more efficient. We’re trying to work their way back in reverse. They’re trying to undo all the stuff that we did a decade ago, to try to make markets more efficient. The same was also true when we integrated Dominion. It’s the same kind of picture. Why would we want to do this? Let prices form. Why are we making this more complicated? Bigger is simpler. One market. Why are we making this more complicated than it needs to be?

And then, of course, there’s the last frontier, some aspects of which I’ve already mentioned. The last frontier--better information, technology, and dare I say, technology has finally caught up with the theory of perfectly competitive markets in electricity. We all know what the prices of all of our commodities are before we consume them, except one, electricity. We have no idea what that real time price is before we consume it. But now we have technology. We can know what that is in real time. We can program our appliances to actually make those decisions. So the technology has caught up with the theory, as opposed to the theory catching up with the technology in this case.

Also, economies of scope and scale. Why do we want to undo that and go back to being these cloistered markets again? But yet that's the path that we're going on with climate change policy in this country.

And then I'll just leave you with the FERC NOPR on gas and electric timing. How hard can this be? This would solve a lot of ills. We can move. The gas industry can move on timing. It makes a lot of things easier. We could have more transparency in the kinds of gas deals that can be done, and that way we can avoid a lot of these other things that we just saw. And so with that, I want to thank you.

Speaker 4.

Thank you very much. I have a presentation which I'm going to through parts of, and other parts not, adapting to a little bit of what we've already heard.

The first thing I want to show is this picture, because I just love these colored weather maps from PJM and MISO, where they show prices. And the most important message I want to convey here is that somebody has broken the software for this website, and it doesn't work with my Bill Gates system. [LAUGHTER] So this is a decaying asset as far as I'm concerned.

Comment: All right, I'm sending a text right now.

Speaker 4: Good. [LAUGHTER] You used to be able to click on the nodes, and it would tell you the prices, and it doesn't work anymore…

This picture actually tells you something else, which is also quite relevant to Speaker 2's comment about thinking about the history. Many of you in this room will remember the long conversation we had about getting up to the point where we could do this. And the argument was that it was politically impossible. It was politically naïve. It was academic pie in the sky. It was technically too difficult. It was never going to happen. We couldn't have actual normal prices. We could only have very large aggregate zones. Well, maybe we could have two zones. And I remember particularly when the conversation took place in New England, when the ISO New England was going through that reform process back then, first we couldn't have one zone, because FERC said that wasn't working, so we had the two zone meeting, and then we had the three zone meeting, and then we had the four zone meeting. And then, finally, I don't know where it was, around 27 zones, we sort of threw up our hands and said, "This is ridiculous!" And I've always been of the view, and continue to be of the view, that it is ridiculous. And what we should do is go all the way. So what's the right number of pricing points? Every bus. And here we have PJM's keeping track and publishing pricing points that's tracking more than 10,000 pricing points right now. And I don't know what the number is in MISO, and so forth, but there's a lot. And there are a variety of reasons both technical and practical that going all the way is actually the right thing to do.

And that's the kind of message and the theme that I want to talk about here today. There's a lot going on in this process of reviewing market design, and we know about the FERC technical conferences that are now in process. I extracted a description from the FERC order about the kinds of things they're looking at on pricing. Let me just say I'm happy to see it. I think their priorities are essentially right. It's very consistent with what Speaker 2 was talking about, and I think it's a very good direction. So there's a lot of motion going on, and we have already heard about what's happening in New England and how they've been discussing this (and the 500 slides. I don't think I've read all 500, but I've read a fraction, a large fraction. And they're very good, and there's a lot that's going on there).

And the theme that I would emphasize, and that people should keep in mind during this conversation, is summarized by the argument here, "The last should be first." OK? So what do I mean by that? When you have vertically integrated monopolies, and people don't have any control, and they don't have any discretion, it sort of doesn't matter. And you can do what you want to do, and use day ahead and forward contracting and other things, and nothing bad will happen, because you're controlling everything. But when you have markets, and you give people discretion, and they get to choose, and they're going to be trying to maximize their own profits like we want them to do, then what's going to happen in real time is absolutely critical, because everybody is going to look to that last step in the sequence, that last stage in the market and say, "Well, gee, if I do this beforehand, and I'm out of balance in real time, is it going to cost me a lot or a little? And how efficient is that going to be? And what am I going to do?" And they're going to make decisions which are going to be conditioned on what they think is going to happen in real time. So even though the real time might turn out to be largely hedged, and only a few things are out of balance, and the volumes that are not priced elsewhere are small, it's driving everything. For example, just think about what it would be like if you said that the real time balancing charge is zero. OK? So you can get it for free. Well, that would certainly change the market. Right? And we would have a completely different kind of system.

So I have always believed, and am arguing again (and it's very consistent with what you've heard here today) that what I mean by getting the prices right, and efficient pricing, is to first focus on the real time, and do as good a job as you can do in dealing with the problems with the real-time market. My own view is that an awful lot of the difficulties that arise in these markets and the imperfections and problems we're wrestling with are driven by failures to get the real time right. And then what we're trying to do is to compensate for what we didn't do by getting there by way of the back door somehow, or through some kind of other products. And it's always much more difficult. And after careful analysis, I've come to the conclusion that fixing the real time market will capture 87% of the benefits of the whole system. You can take it home with you. That's my number, 87%. [LAUGHTER] And it's the first thing that we should do, not the last thing to do.

I've gone to more meetings and more stakeholder meetings and RTO meetings and conferences, and they say, "Well, we understand that getting scarcity pricing right, for example, in the real time, is really important. And as soon as we get this capacity market right, we'll turn our attention to doing that." I heard that in 2005 from Andy Ott, because the pressures were to deal with the forward markets rather than to deal with the real time. I think that's the wrong sequence, and I think dealing with the real time is absolutely critical. Then you can worry about the day ahead market and make that as consistent as you can with the real time, because you're never going to get things perfect, but you're going to have to do something.

And then you deal with the problems, particularly that Speaker 2 was talking about, about the non-convexities and all of that. And then forward prices and other contracts will come out naturally in that process. So, when it comes to getting prices right, the last should be first.

There's a paper on my web page, and also on the HEPG web page, that you can download, which is what I'm summarizing here under the heading of "dispatch based pricing." And the argument there is, how do you do this in the real time? And what does that actually mean? To make things consistent with what's happening--to have the operators making their decisions, and you try to price as much as you can. You won't get everything, but you can do very well. And the paper goes through a number of examples. I'm only going to briefly describe two of them here, because they're relevant to the conversation that we've had, but you can go look at them.

The first example is dealing with what's sometimes called ex-post LMP. There's a terminology issue here about dispatch-based LMP, but the idea is to utilize the actual dispatch to simplify the model for calculating consistent locational prices. And I picked that example not because it's an innovation and not because it's new, but because we're already doing it. And it's something which was at one time viewed as an extremely complicated problem. And it was going to be really hard. And how can we possibly do this? And then we sat down and thought about it for a while, and figured out, "Hey, this is actually trivial, almost." It's actually quite simple, and I'm going to explain why that's true, and we have the experience now, and that's how we got to doing 10,000 locations where we can produce these prices. So it's something that people often don't appreciate when they talk about how complicated this is going to be. We've already done this on probably what is the hardest part of that problem, and the other things are not going to be so difficult.

And then for the second example I'll say a couple of words about Texas-sized scarcity pricing, and the operating reserve demand curve for dealing with that scarcity pricing. (The other examples on the list, incidentally, are things that people have talked about--demand response, reliability unit commitment, voltage support, and the extended LMP stuff which I'm not going to talk about except if we get into it into questions, just because I don't have time.)

So the first example was, bid-based security-constrained economic dispatch, and as everybody in this room knows, the security-constrained part means contingency constraints, so we're worried about a line falling down, and the line falls down, and we have to still be feasible with all the flows redistributing on the network when the line falls down. If something like this happens, it's going to create a different network, so the power flows into that network are going to be different. So for every constraint, it's a contingency constraint, there's a completely different network. And then there are thousands of contingency constraints. And then there are thousands of constraints on every one of these networks. And they all have different flows. So, in principle, there are millions of constraints that are driving what's going on there. And this sounds like an impossible problem to solve. And it's not easy. But, happily, the system operators are doing it and have been doing it for a long time, and they're good at it. And they have all kinds of techniques for dealing with that, and so on. And the philosophy of dispatch-based pricing is that when the system operator is solving this problem, he's doing a really good job. And then we take that solution, and interpret that as the solution to the economic dispatch with all of these security constraints.

When you take that idea, and you look at all of those constraints (you can go through some examples. I'm not going to go through them here, because you're familiar with this, but there are just multiple constraints that arise because of this problem), what it leads you to is the following situation, which is, there is a closely related economic dispatch problem, and the economic dispatch problem linearizes, so it makes simple, these constraints, and it uses only the constraints, in the convex case, that are actually binding in the economic dispatch. That turns out to be a very small problem. So the original problem had a million constraints, and the actual pricing problem has, what, on a typical day? Ten, or something like that, and maybe 20 on a bad day, when you have various things binding all over the place. And so we can get that solution and get it very quickly and very easily. Of course, it depends on knowing the economic dispatch. So it's not a way to solve the economic dispatch problem, but once you solve the economic dispatch problem, calculating the prices in the next step is relatively simple, and we know how to do it, and we can make the approximations that are necessary, and we've been doing it, and it's not perfect, but it's pretty good.

And what we're talking about is doing similar kinds of things in other kinds of applications. So one of the applications is dealing with shortage pricing, and I'll go through this quickly, because most of you have seen this before, but this is the operating reserve demand curve argument that operating reserves are valuable, but they're not infinitely valuable. And when you get above the basic minimum levels, you would be willing to pay to get some incremental operating reserves, but the more operating reserves you have, the less you're willing to pay in order to get them. So it's downward sloping. So it's not a big conceptual leap, but it is quite a change in the way these things were originally defined. And if you take and include some kind of an operating reserve demand curve with the energy dispatch, as they do in New England and other places, and PJM, then you can do co optimization, and the co optimization then affects the reserve price, and it affects the energy price. So it propagates through the whole system. So even though the operating reserves are actually a small part of the total story, they can have a big part of the pricing, and they provide a proxy for this missing demand participation that we haven't had, and they actually might be the chicken and the egg problem in order to deal with this. And the operating reserve demand curve is an idea which has been around for quite a while, and it's been implemented in various places. The problem is, in the places (other than I would say, now, Texas) where it's been implemented, it was implemented a long time ago when we didn't quite know how to do it, and we sort of had a rule of thumb for these capacity penalty factors and all these different kinds of things, and appealing to shortages when they occur, as opposed to treating the demand for operating reserves as there all the time. And we didn't derive it from first principles.

And I'm going to describe what's going on in Texas starting in June this year, and that is the operating reserve demand curve, with demand derived from first principles. I kept saying this when I was down in Texas, so somebody asked me, what do I mean by that, by these first principles. So I wrote down a list, and you can see the list here of things to discuss about operating reserves. But the basic idea is very familiar to anybody who's been around the electricity system for a long time, which is that the reason the operating reserves are there is because we think something bad might happen in the next short interval, like an hour. And we want to have enough spinning and non-spin reserves, like quick start stuff, that's available, so that we can respond very quickly to these things, and then we'll start redispatching and adjust when we get back in. But we need things in order to deal with the very short term problems that you're going to have. And that can be related to the probability that we get into a situation where we have to curtail load. And we always want to avoid that, but we might get into a situation where we have to curtail it, and there's some probability that that will happen in the next hour, and the higher that probability, the more we're willing to pay for our operating reserves in order to get incremental operating reserves. And so that's the loss of load probability curve that you see in this graphic. And then it's coupled with the minimum contingency operating reserves, which is where, as a simplification, but an approximation, the argument is that when you get below this level, of operating reserves, you will curtail load in advance in order to preserve operating reserves, because you have to have a minimum level in order to avoid cascading failures throughout the system. And so that just translates the loss of load probability curve. That's why it shifts to the right in this picture, and you get this sort of funny shape. And when you're below what they call in Texas the "X level," the idea is, you are curtailing, and therefore you should be paying the value of lost load, and when you're above that level, it's a probabilistic story, which is the curve that you see there. And that's the operating reserve demand curve. You can put it in place with multiple categories, and they have two in Texas, and they're nested, and so they have this, what is essentially spinning reserves, and then non-spinning reserves, and you don't have price reversals. There's a connection between the two and all that kind of thing. So you can actually do that. But the thing that's important about this is not the idea of pricing shortages, but actually explicitly connecting the price as a shortage to what is admittedly a judgmental estimate of the value of lost load. And then this loss of load probability. And the numbers are larger than the numbers that are being used in these penalty factors in other parts of the country. So this is what Speaker 2 is talking about when he talks about "Texas sized penalty factors," and they've actually put this system in place.

Now, in the discussion in Texas, this is in the context of the question, "Is this going to be enough?" in order to address the so called "missing money" problem, and that's a longer conversation we can have. I won't go into it all. I just want to make a quick point here, which I think is relevant, and that is that if you're going to do something to tweak the market, in order to address the reliability and the missing money problem, because you want to have a more reliable system, it doesn't follow logically that you have to do this through a capacity market. So there's an alternative, and the alternative is to tweak, for example, the operating reserve demand curve, because that's actually targeted directly towards reliability exactly when you need it, and if you want to have an extra margin of security, then that's when you want to have it. And so you should do it then. And if you want to do that (and whether or not it's a good idea is a discussion we can have) but if you want to do it, there's a question about how do you do it. And there are basically three parameters that you have available to discuss. One is the value of lost load. The other is X, the minimum contingency level, and the third is the loss of load probability. And this slide summarizes my view on this matter, which is, you don't want to mess around with the first two. Not too much, because that's going to create incentive incompatibility problems if you're not really charging the loss of load probability. You want to use something that's implicitly different than the one you're actually going to use when you start curtailing people. You're going to get gaming response. The same is true for the minimum contingency level story. But those problems do not arise with the loss of load probability. And so having a conservative estimate of the loss of load probability is quite consistent with the notion of having a security margin that we want, because we don't quite trust our models, and we want to be a little safer than what the data tell us and our models tell us would be the loss of load probability. And if you do that with the Texas sized operating reserve demand curve, and I did (this is illustrative, I just took the actual number, but then shifted them by one standard deviation and then two standard deviations), you can see what's going on here. And I think one standard deviation is pretty conservative. And two standard deviations is really conservative. And then you can look at the numbers, and what it produces in terms of these scarcity prices that would be applied there, and you can see they're really quite different. And so, what's the right answer, I don't know. But this is a non-trivial tool that could have a major impact on the incentives that people pay, and the kind of impacts on the missing monies.

So that's an alternative, what's called the augmented operating reserve demand curve.

There are a whole lot of other questions that come up for this, and I have all the answers on the last slide. [LAUGHTER] The most important one, I would emphasize, is (and I think it was Speaker 2 who made the same point) that one of the advantages of this operating reserve demand curve story is that with real numbers, the Texas sized numbers, in it, it's completely compatible with offer curve mitigation to deal with market power. So if you have a $100 offer cap, because that's the real variable cost of the generator that you're dealing with, and it turns out we get into a tight situation, and the price is $3,000 or $5,000 or $8,000 per megawatt hour, that generator is not withholding. They're not exercising market power. But they do get paid the $8,000 per megawatt hour, even though they're offering at $300. And that allows you to distinguish between prices that are higher because people are withholding, which is bad, from prices that are higher because we have shortages, when it is good to have the higher prices (not that the shortages are good, but to have higher prices in those conditions). And that's a big advantage of this approach that I think is underappreciated by regulators, but one that we should look at.

I have a lot to discuss, but I'm over my time here, and I'm going to stop by reminding you of the basic point, which is the last should be first, get the real time prices and good as you can get them, and that's the first thing to do, but only when you've run out of ideas should you then turn to other things in forward markets, capacity markets and the like. And my second piece of advice is, how far should we go? The answer is, go all the way.

Question: This is a very quick clarifying question about what you mean by ex post pricing. From your explanation, it sounded like post security constrained commitment pricing, as opposed to post who moved based on the signals. So what did you mean by ex post versus what I think of as ex ante and ex post?

Speaker 4: The reliability unit commitment that comes after the initial economic unit commitment story. I think, for reasons of the incentives that you want to provide, the pricing should be done essentially the way they do this in New York, which is, we do the economic dispatch, and then we do the reliability unit commitment. Then we do another run, which is a pricing run, which incorporates the units that were committed in the reliability unit commitment, as opposed to PJM, I believe which does not do this.

Comment: They do not.

Speaker 4: And so I can go through what the incentive issues are there in order to make that consistent. But that's a day ahead story. That's not a real time story.

Question: Under this design, what do you tell the Governor when you say, "I maintained 3,000 megawatts of reserves, but I shed load?"

Speaker 4: It's interesting. This question has come up in a couple of different settings, but I can't believe this is actually true, that you will go down to having no reserves before you will shed load, because they you have a cascading failure problem, because if something fails at that moment, it's too late, and so you can't adjust, and you'll have the Northeast blackout. So that can't be literally true. So my argument is, whatever it is the system operator is actually doing, that's what you should price. And if the system operator is going to zero, then OK, that's what you should do. And if they're not, then you should price that, too. This is the dispatch based pricing idea. Price what they're doing.

General Discussion

Question 1: Thanks. My question and/or comment arises from Speaker 1's talk. And it's sort of a two part question. The first is that you made the comment, something along the lines of, as load grows, and absent other responses, there is an incentive for the now load serving entities, distribution utilities, to make investments to maximize their rate base. And I was wondering, in a state where the electric utilities do not own any generation, how they do that.

Speaker 1: First, let me clarify for the benefit of those who are not familiar with this, that as part of the restructuring in New York, the generation was divested, for the most part, by the utilities, so the utilities did not own generation as part of their portfolio. So what I'm suggesting is, the utilities are still investing in transmission and distribution assets, and the capital that goes into transmission and distribution at this time is reaching about $2 ½ billion a year. Some of it is designed to meet peak loads. So all I'm saying is that as load grows, to meet the needs, they've got to invest in that. Questions like, "Can I meet this with other non-wire solutions, whether it's energy efficiency or demand response or some other distributed energy resource?" are not necessarily at the top of the mind for the utilities, unless they're incented to look. And we have done some. For example, like some other states, we have revenue decoupling mechanisms in place, which means that utilities are indifferent to loss of sales from energy efficiency. It's still not a profit making motive, but at least they won't lose the money as energy efficiency grows. So that's the comment--their incentive is to build T&D assets to meet their needs, not necessarily to look hard for other solutions that potentially could be cheaper.

Questioner: The other comment you made was on demand response, and you said something along the lines that it's difficult to factor demand response into the pricing and the grid and so on. And I do know, and it was commented on earlier, that the MISO guys do a daily day ahead forecast. And it was unclear to me why any demand response that's in the system, either any kind of load management, peak shifting, peak shaving, etc. or actual behind the meter generation, can't be and isn't factored into those forecasts.

Speaker 1: What I'm saying is that today we do have energy efficiency baked in. Energy efficiency in New York, at least, is considered as a load modifier. So going into the forecast, energy efficiency is taken care of. When you look at demand response, there are at least three products. In the capacity market we call them special case resources. In the energy market, you have demand response, and then in ancillary services, the capacity market, participation is going down over a number of years. And day ahead demand response, to my knowledge, hasn't attracted a lot of interest. And neither has DSASP (the demand side ancillary service program) attracted a lot of interest. So on the one hand, I do hear firsthand from customers in New York, large customers, who are very willing to participate and offer demand response. But the existing products just don't work for them sufficiently. So one of the struggles is, what's the disconnect, and how do we fix that? Are there better ways to find newer products, different products, that would meet the needs of both customers and the system?

Questioner: OK, thanks. I suggest maybe it's a good idea for you guys to look across the river to New Jersey, where behind the meter demand response has really moved significantly, and that's a whole separate issue of incentives and stuff like that. But in New Jersey, solar generation, for example, is a significant factor in their behind the meter DR sector.

Moderator: As long as we're on this topic, I would ask the other panelists, could you explain how demand response at the retail level affects your pricing models?

Speaker 3: Well, in PJM, to the extent that we understand what's happening as reflected in price sensitive demand bids day ahead, or price responsive demand in real time, yes, it's going to factor directly into price formation. But to the extent that there's something going on that we are unaware of, then it's going to affect price formation in the sense that we may end up committing more units than we may need, because we don't have that operational information, which then would update our demand forecast, and then we would get some of the units off the system. So we'll overshoot a little bit, and then we'll update that forecast in real time, as we go through real time operations. But I think what's crucial there is that there has to be a linkage between retail programs and the wholesale market. I mean, it could be all going on at retail, but we have no idea. We don't have that operational visibility in real time.

Moderator: Why does it matter, as long as when you're doing your forecast you see what the expected load is? Why does it matter whether it's happening on a retail basis or not?

Speaker 3: What I'm suggesting is that if we don't know what's going on, if we don't know it's there, how can we account for it? It's a visibility issue. That's all I'm suggesting. I mean, we've got to have visibility to it, one way or another.

Speaker 2: In New England, to date, we haven't had a lot of real-time demand response. It's not part of our market. But as Massachusetts, for example, among other states, increases the penetration of retail-level solar, we are needing to develop new tools so that we can predict that. We've been doing something very similar with wind over the last couple of years. And that's proven successful, and probably the next step we need to make is to say, "OK, we know we have 500 megawatts of behind the meter solar in Massachusetts. That needs to be sort of explicitly included in our load forecast." So, at least in the near term, that's our expected adaptation.

Speaker 4: I think there's a more important long run question, which is the chicken and egg issue. So as long as we have peanut butter smearing of the payments that go for all kinds of things, and it doesn't get into the real time prices, then it doesn't make much sense for people on the demand side to pay attention. It just isn't worth the trouble. But if you had real time prices that were politically incorrect, but reflected what was really happening, then pretty soon it must now be worth their while to start paying attention, and then participating, and then you'll get investments, and then you'll get all the institutions, and then you'll start having as much demand participation as you want, or as you can get. It won't be everything, but it will be relevant, and it will also make the problems created by the operating reserve demand curve, because there is an administrative component to it, become less important, because the market will have a much more important part of setting what the prices turn out to be. So I think there's a long run problem that's actually driven by these short run prices that would be fixed if you had prices that were actually going through that we don't have at the moment, except in the "Texas-sized" penalty. (I'm going to use that a lot. I like that.) Thank you. [LAUGHTER]

Question 2: Thank you. I take it that it is self-evident here for all of us that a market design is a work in progress. I see that there are two categories of problems. There are internal problems to the market, and there are issues about the barriers to demand response--capacity mix, and the reserve market, and the capacity value, and so on, that have been covered well in this discussion. So there are things that we need to do on that score. Speaker 4 very optimistically said that we are 80% there, and he made it seem very easy. But don't believe him. [LAUGHTER] Even if he said it's 99%, it's tough, because right now the task is how to protect the 87% that works while we are fixing the 13% that is a problem. That's a tough problem.

Now, having heard all these problems, I would like actually to look at our ideal market, more focused on the supply side, and I'd like to get some comments on what the new market design innovations could be brought to bear to provide a better solution to many of the problems that remain, and while we're trying to protect the functioning of the existing market. I think, in a sense, that we are lucky--except for the California crisis, so far things are largely working.

I would like to use a key word, a key phrase mentioned by the first speaker, and to sort of launch some discussion on the panel here. The key word here is "incentive regulation." You know, I take it, that the theories of market design and pricing that we see today were largely formed in the 1990s (not including, certainly, the landmark paper by Bill Hogan), and as I recall, the last survey of the theory of peak load pricing was done in 1995. A lot has been learned since then in incentive regulation. I just want to mention two dimensions here. One is the multidimensionality of auction design. And the auction design has developed very vigorously in this area to allow multiunit and multiattributes, and all the multidimensional model products. Many of the problems that we hear today are not really difficult in light of the multidimensional auction design. So we learned a great deal in theory and practice.

And the second dimension is the dynamic interactions of contract and pricing of ex ante incentives and ex post incentives, of investment incentives and the performance incentives. Now, in that area, incentive regulation also had sort of come with a great mileage. And we heard about the DR problem, which reminds of me of how people used to talk about spot pricing back in the early 1980s, when people said things like this: "Implementation of instantaneous spot pricing is impractical because of the associated communications, controls, transactions and the metering costs. Spot prices are determined and posted before they come into effect." So basically that said that spot pricing is inherently ex ante. So we have come a long way, and Bill contributed to that, and the ex post pricing now becomes more a reachable goal. But on the demand side, we still haven't reached that. So I think what we are going to see here on the demand side and with demand response is a mixture of ex ante and some ex post pricing. How do we actually make sure that this mixture can work seamlessly on the demand side, and then between wholesale and retail market? There are still many unresolved issues. So my question for the panel is, are these some of the innovations that are worth actually stretching our minds to? And maybe we will feel uncomfortable about the complexity, and I'm mindful of market transparency. But I'd like to say that Speaker 4 has the solution here. Going all the way, is it the right thing to do? So what is the right thing to do? That's my question.

Speaker 4: Well, certainly I think going all the way and getting the prices is as good as you can get them, and trying to push hard on that, is the right thing to do. I agree with you, particularly about the auction theory stuff. An example of something which I had nothing to do with, but I think it's a terrific idea, and it's been implemented and working for quite a while, is the New Jersey basic generation service forward hedging auction for energy. But if you put that into the language that the questioner was talking about, it's a multiunit dynamic descending clock auction, with per progress rules, and people can switch back and forth. So it allows very, very complicated tradeoffs in determining who's going to supply which tranche with the future load and all the other kinds of things. It's completely compatible with a well-designed real time market. It provides hedges going forward. So it's very good, and it's a terrific idea. I keep recommending it to everybody I ever see, that they should think about this, and I was making the case that with a slight change in the New England proposal, that would be not so easy to do, but nonetheless a doable thing. It would become almost that, and then you would be in a position where you could say, “I could do this now a lot more efficiently with this multiunit auction theory than the way it’s being actually done in the capacity market proposal.” So I think that is a good example of exactly what the questioner was talking about.

Speaker 1: Let me comment a little bit differently. I cannot disagree with the first principles of Speaker 4--getting the prices right in the day ahead market and in real time. Absolutely. When you get to the retail, though, as he pointed out, there are limitations in terms of what you can reflect in retail costs, retail prices, and as Speaker 3 said, this is one product that people don’t even know what the price is before they consume it. And if you look at the loads, probably a third of the load is more industrial, flexible, sophisticated consumer load. The remainder, residential and small commercial, which is a half to two thirds of the load, maybe, depending on the state and region, doesn’t necessarily experience dynamic pricing the way the large customers could. So how do you animate this market? And as also, as Speaker 3 pointed out, technology is catching up. We have, in the last decade, numerous new players coming into the market with new technologies that we haven’t seen in the ‘80s and ‘90s. Very sophisticated players, Google and Microsoft, they’re all expressing interest, at least in New York. We have talked to them. They’re wanting to come in with new products. Some of you have heard of simple things like the Nest thermostat. How many of you have heard of the Nest thermostat?

Speaker 4: It doesn’t work in my house. [LAUGHTER]

Speaker 1: OK. So that’s an extremely simplistic example of perhaps controlling air conditioning load. In our New York City, I’m told there are six million window air conditioners. That’s about 2,000 megawatts of load in the city, peak load that’s driving the need for generation. But how do we get this technology in place to affect that load, to make the customers excited and interested in doing this? Similarly, there are other companies that are coming in, putting in building management systems within commercial buildings. We have hundreds of skyscrapers in the city. And there are new technologies now that can automatically control load within those buildings, and there’s a pilot program where now the utility can actually control the load from the utility control center, and that provides the distribution utility the comfort that they have control over this load, and they can reduce it by whatever, ten megawatts or 15 megawatts. That will go into the planning, if they have control and comfort that this load can actually be controlled. Once that goes into the planning, then you can reduce the distribution and T&D investments going down the road. So you need price signals. You need comfort that they work, these instruments, and that the utility has control over these loads. And all this technology that has come up in the last few years on the communication tools and the Internet and the ability to communicate, I think these are helping really look at things. How can we take advantage of these, in the absence of being able to send complete real time price signals to the end use customer? Can we animate these providers, this new marketplace, to come in and provide these products and services? And I’ve heard firsthand from many industrial and commercial customers, “We want to take advantage of these tools and play in the market. The existing products ain’t sufficient for us. So can you come up with new products?” Maybe it’s not the bulk power system, because, as Speaker 3 said, perhaps they’re not visible to the bulk power operator. Maybe it’s the distribution utility that can take advantage of these potentially hundreds of megawatts. I just talked to one of you who’s putting in a DG system, right after Super storm Sandy. It’s going to operate for a few hours in a year at the most, but it’s there. And there are going to be hundreds of such megawatts that are going to be installed very soon because of customer needs, for their own benefit. But the operator doesn’t know. The RTO doesn't know. The ISO doesn't know. They're all behind the meter. How can we tap those for the benefit of the system, both from a reliability and overall price reduction perspective, not only at the wholesale level, but even the distribution level? I think that's the challenge we are trying to think of. How do we bring these pieces together to make the market more efficient?

Question 3: First, to the ISO New England and New York panelists, it would be interesting to hear your thoughts on how the surplus hydro north of the border is or could be better integrated into the markets. And then, second (and this is for all of you) Speaker 3, with PJM, nicely pinpointed the visibility issue of demand side response behind the meter, and I'm wondering if, to your knowledge, any rules or serious conversations are underway regarding sort of midlevel market aggregators for demand response behind the meter.

Speaker 2: On the issue of the surplus hydro north of the border, I guess I've got one point and then two observations. The first point is, boy, Hydro Quebec does a pretty good job of maximizing the utilization of those resources, given the system that we have. Presumably they make a lot of money when they're selling to us during high priced periods. So we see very heavy utilization of the existing tie lines exactly when you would expect to see it. When we don't typically see it is when they have coincident cold weather with us, and there's probably not much to be done about that.

In terms of specific things that could relieve constraints, one would be if we were able to count reserves over the ties. We don't do that today. So we're probably underutilizing their rapid response capability in Quebec, to an extent. And the other one would be that just increasing the capability of the transfer limits from Canada would…if you just did that, I have full confidence that the traders in Hydro Quebec would do the rest.

Speaker 1: So speaking for us, we do have a project in the pipeline. HQ wants to connect and sell directly into New York City, and it's 1,000 megawatts through hundreds of miles of transmission line. And we love merchant projects, as I said before. This is going to be a merchant project. We have approved, from a state regulatory perspective, the transmission siting article. We call it Article 7. And they are going through the federal permits. I think they're pretty close to getting it done. Once it's in place, sometime in 2018/19, I think that will be an excellent addition into the New York City high priced market that's clean energy resources. Although it's 1,000 megawatts of energy, I don't know if it has 1,000 megawatts of capacity or 650. There's some discussion of --

Comment: We don't know yet. But at least over 500 megawatts…that's a win/win/win from many perspectives. One, it's price. Two, it will reduce emissions in the city, because you're replacing some of the very old generation in the city with cleaner resources. And there's fuel diversity, and it helps from a price volatility perspective, too. So we love those projects and hope they move forward.

Question 4: Early on, after the Polar Vortex, it seemed that both ISOs concluded, "Well, we really have got to get better pricing in the energy market." That seemed to be the takeaway from, for example, the PJM white paper that was done by staff. And then I have been following the trade press about what PJM is actually doing, which struck me as a lot of administrative contortions to sort of get to the same point. And I think, Speaker 3, you alluded to it, but it just strikes me that when you boil this all down, it's about politics, that you just aren't willing to face the headline risk, when the reality is, at least based on our experience, that when prices do go up, there may be an initial reaction the first time, but if in fact your load serving entities are hedged, and your actual customers are on fixed rates, there's not going to be that much impact, other than that you encourage even more hedging going forward. So am I wrong? Am I missing something?

Speaker 3: I don't think you're wrong. But I think there is some detail missing in the sense that there is the political risk. I don't think I can sit up here and tell you that that's something that we don't consider, which is part of the reason why we've chosen to go down the road of a capacity construct for resource adequacy as opposed to letting prices rise in the real time energy market as a first cut, as Speaker 4 has suggested. During the Polar Vortex, we actually had two problems. One was that the performance of capacity resources was just terrible, as I showed you. But I think more to the point, we did have price formation problems, because of the fact that we had units saying, "I need to buy gas for three or four days, just so I can have it on that cold morning ramp," depressed prices throughout that time period, because effectively that looks like price takers.

One issue that I didn't bring up that I could very easily have brought up, was, how do we manage interchange during this whole thing? We got a lot of interchange during the Polar Vortex period in early January and then again in late January. And that interchange would come flooding in and depress prices, because there is no price mechanism. They're all price takers. So we have committed units out of merit order, committed units expecting to need them, and then we get flooded with interchange, which depresses prices. So we've got to do something about how we price interchange. And, actually, we've got a stakeholder group looking at that. But in terms of the energy pricing mechanisms that we have in place, those seem to work pretty well, except for the fact that we had this $1,000 offer cap, and well, it actually cost more than $1,000 to actually generate the power in some cases. But we still have these issues with performance of the capacity resources. And if we had an energy only market, yeah, the energy prices would skyrocket in that case, and, sure, then maybe we would see some demand response at that point.

Questioner: Well, I'm not even talking, though, about replacing your capacity market with an energy-only market. I just mean that if the generators are exposed to the higher prices, for example--and this has been our experience, after the February 11th freeze, they learn really quickly they've got to keep their units in shape, because if they don't, and they've sold day ahead or have some other obligation to schedule, they lose a lot of money really quickly. And so they pay real attention to being ready on the cold events. And in some cases, generators will keep their units spinning in order to keep them hot, because of the risk of tripping when they start on a cold morning. And the same thing on the load side. You're actually encouraging load serving entities to respond to the higher prices, because they have a chance to monetize. Well, there's a physical risk, if they've under hedged. But, I mean, it just seems like it just drives all the right behavior on both the resource side and the load side.

Speaker 3: Right. I mean, look, the generators face the same incentive in our market as they do in any other market. They have a day ahead commitment. They've got to buy that back in order to pay a premium price for it. And they're just simply leaving money on the table, quite frankly, in either case. But the prices are much lower than what you would see, say, in Texas.

Speaker 2: There are two categories of pricing that we're worrying about. One is in shortage events, and we actually have raised the RCPFs (reserve constraint penalty factors) not quite to your levels yet, but they're getting up there, at least relative to where we had been. So that's certainly progress. But the other aspect of pricing, which dominates 98% of operating hours, is, you know, pricing when you actually aren't short of reserves. That's also very important, especially when gas prices are wildly higher than all the other fossil fuels that you see, basically oil and coal, in New England. Hourly offers, for example, is a project that will, during a large majority of hours, allow the gas price to be seen more directly in LMPs, and that's also very important. So I wouldn't say that we don't think that the RCPF is important. It's more that there are a whole heck of a lot of problems. So what you're seeing is a laundry list of problems, some of which fix this part, and another one might fix this other part. But you sort of need them all to get it to work better. And unfortunately, ISOs do have limited resources, so only so much can happen at a time. And we have to prioritize.

Question 5: I don't think I'm disagreeing with anything that's been said. And I realize that three out of the four people, maybe four out of the five people, have political concerns they have to worry about. But suppose we just laid the political issue on the table for a while, and stopped, and I realize you have to deal with the short term problems, but let's look at the long term, and just simply change one thing, and just simply say, "Let's focus on assuming we can get enough price responsive demand into the market, what happens?" Now, when I say "price responsive demand," I mean that demand is simply going to tell the ISO at what price they're willing to buy and how much they're willing to consume at that price. And if you put that into the day ahead and real time market, and if you take a generous assumption that there's enough of it so that the market will clear, it solves all of your problems. Speaker 4's demand curve for reserves becomes an incentive mechanism for people to bid correctly. You can make the system reliable by curtailing. You get the price, not from administratively determined factors, but you get it from what the demand is telling you. And it has a virtuous cycle. When people realize that the price could go up, they start to hedge more. And they buy hedges, and they do bilateral contracting, and generators can essentially take the bilateral contracts to their financiers and make the financiers happy, and all that kind of stuff. And if you just start thinking about it that way, all of these things, they're important, but they're sort of coming at this problem from around the bend, and if you could only get price responsive demand….

We have all the equipment now. I mean, we can measure what they're doing. If they're not telling us, if they're not doing what they are telling us they're going to do, oh, by the way, you actually tell this entity that he no longer has to be in the capacity market. You don't give him a credit or whatever. You don't pay him for it. He simply doesn't have to be in the capacity market because he doesn't need reserves. He basically can be chased off the system via price. And so consequently, a lot of the price formation problems disappear, not all of them, but a lot of the price formation problems disappear. And if you start thinking it through, now, I realize there are a lot of political problems that Texas is willing to deal with, but apparently no one else is. The capacity market may simply shrivel up. You don't have to do anything about getting rid of it or anything. It just may die of the fact that it's not that necessary anymore. Demand can be an ancillary service, because if it's on the system, it can serve as reserves. You don't have a baseline problem. You don't have all these other things you have with what arguably is now illegal. And you have to argue that price responsive demand is something different from demand response, which is now a lexicographic argument. And to me, now, the question then becomes, how do you sell it? And it apparently was sold in Texas. But I think it's really important to try to think through what would happen if you could get price responsive demand, and whether or not not having to pay a capacity payment is enough. Now, once you do that, you may find that the demand wants to do things like have notice requirements, like how long does it take to start up, versus how long the generators take to start up. The demand may have to take time to shut down. Demand may want to run a shift or not, and that can be part of the offer curve. And there may be a whole bunch of different ways to represent that in the market.

But it's really important, in my opinion, to give this signal to the system, because that's the way the operator gets to make it reliable, and the reliability people hate the idea that you're going to send a price out, and you're going to expect demand to respond. In this case, they're telling you when they're going to respond, so the system operator can actually make the system reliable by depending on that commitment to respond.

So why aren't we discussing this?

Speaker 2: I'd be happy to discuss it. I would love to see a situation with vast amounts of price responsive demand, because a lot of the problems we're talking about here go away. The problem, as someone who works with an RTO, that I have, is that I can't make that happen. Even in New England, where they're putting in these meters, it's not clear that we're going to get the retail rate designs necessary for end use customers to fully utilize those meters.

Questioner: By the way, I expect them to be utilizing those meters when you get the demand curve correct. I mean, you look at the studies, and the value of lost load is somewhere between $1,000 and $100,000 a megawatt hour, depending on which study you look at. It would be much nicer if the demand would just tell you.

Speaker 2: I completely agree. And I think we're moving--we're certainly a lot closer than we used to be. We're looking at $3,500 plus pricing. That's going to get some people's attention. And Speaker 4 said that it's a chicken/egg problem. I can't extend that metaphor anymore, unfortunately, so I'll have to use a different one. We've cracked the door a little bit. And hopefully folks will see those prices and say, "Hold it. Maybe we should send these prices to retail customers, and via better rate designs, or different rate designs, and see what happens." Because there's not the unbounded pricing possibilities that I think folks are afraid of. I've talked to state regulators, and they're afraid of somebody's grandmother in an apartment that gets hit with a huge electricity bill. And maybe the only way to get there is small steps, not one big step.

Questioner: I'd say regulators are worried about a *poor* grandmother in an apartment somewhere. Do we care about the rich grandmothers?

Speaker 2: Fair enough.

Questioner: And we can identify poor people, and we have lots of programs to deal with poor people, instead of suppressing the price of somebody's pool being heated properly.

Speaker 2: But just because an economist says, "Oh, well, if we compensate them with a fixed payment of $98, they're on a higher utility level than they would be if we just took the money away through higher prices and didn't give it back," that's not going to sell with state regulators. It's going to matter how big that bill is when they get it.

Questioner: See, you've taken the argument off the table now.

Speaker 2: I don't think I've taken if off the table. I feel like when I've sort of raised these issues, these are the arguments I'm getting back.

Moderator: We actually have all of this in place, FERC approved. Put demand on the demand side of the market, exactly as you've described it. But we're missing a necessary condition, and that is partners at the state level, state regulators that are willing to let those prices rise to their retail customers, and retail customers themselves who are willing to change and allow that. Because if there's one thing that's more American than apple pie, it's fobbing off price risk onto somebody else. [LAUGHTER] And I'm going to purposely poke the bear and say that. In fact, I'm going to use something I used at dinner last night. I call it the "law of conservation of risk." Risk can neither be created nor destroyed. It can be hidden. It may be unknown. But you can also transform that from price risk, into reliability risk. And that is precisely what we have done in this industry. Because people don't want to face those high prices, as you've suggested. Effectively what you're doing, as where Texas is going, is your endogenously determining the installed reserve margin, in real time, based on how people react to prices and things of that nature, with Speaker 4's operating reserve demand curve. But instead, we've said, "We don't want high prices. We want low prices. And if somebody else gets curtailed, great. I've still got my low prices."

Questioner: Are you arguing for the ISO as a risk manager on behalf of the customers?

Moderator: I am not.

Questioner: That's what you're doing.

Moderator: I am not arguing that. What I'm saying is that that's effectively what has happened, because we have become the risk manager, but we're managing reliability risk, because that price risk has been transformed into reliability risk. I'm agreeing with where you want to go.

Questioner: Who cares whether it's reliability risk or not. Reliability costs money.

Speaker 1: I do agree with what you're saying, as a state regulator. In the absence of the ability to send those price signals on a real time basis, given the limitations, what we are trying to do is find alternate ways of providing that impetus for the customers to participate in the market through aggregators, demand response providers who are coming in and using the distribution utility as a way to make it happen. I don't believe we can send hourly price signals to residential customers real time or day ahead. It's going to be monthly bills, bimonthly bills, flattened, hedged… So we need to find alternate ways of accomplishing the goal.

Questioner: By the way, I'm not proposing that everybody be in the system initially. You just let the big guys go first.

Speaker 1: We do have the big guys on hourly pricing. As I said, 20% of our load is on hourly pricing. And they didn't want real time pricing. They wanted day ahead pricing, so they can respond, for example, send the shift home the next day.

Speaker 4: They can do that with price responsive demand.

Speaker 1: And as I said, our DADRP (day-ahead demand reduction program) penetration is pretty minimal. For a variety of reasons.

Moderator: As one of the state regulators who the problem of this inefficient economic program is being blamed on, I'd like to say that in general we respond to what the consumers want. It's interesting that you said to just let those who want to participate, because that's the exact discussion I had earlier. And I hope some of the others in that discussion will comment.

Speaker 2: By the way, Speaker 4's graph tells you how to get them to respond. When they're threatened with $10,000, they start to figure out how to respond. [LAUGHTER]

Question 6: So let me pick up on that. When I was on the Ohio Commission, we actually did have a pilot in AEP, where we had residential real time pricing. We had thermostats that were bidding into an interval distribution level market, about whether or not the heating or cooling in that residence was going to operate over the next 15 minutes. And the result that we've seen so far is that there was a high degree of consumer acceptance from those consumers that got enrolled in the program. So it's not impossible to do this. You can also offer various kinds of two part pricing. We've talked in here before about consumer subscription pricing, where consumers can essentially hedge by buying an insurance product if they want to do that, in addition to getting a real time price. So there are ways in which regulators could deal with this, or suppliers could deal with this.

But I think the other thing that got mentioned here earlier, and is potentially changing this dynamic is the introduction of technology, whether it's the Nest thermostat or other things like this, where you've got essentially automated customer choice technologies. This is taking what Kayak does for your airline choices and moving it into your thermostats and your water heaters and your other devices. So the devices can determine what's the best time interval in which to use electricity. And most of the devices that we have either are associated with thermal inertia or have some degree of flexibility in when they can use price. And that is, I think, a potentially game changing thing that could be happening in the electric system. There are some things that we need to do to facilitate it, including changing the settlement systems in some places, so that suppliers actually get settled on what their interval load profiles are, and not on some representative distribution company load profile. And that could begin to then create the incentive for suppliers to offer these devices along with an energy product into these markets.

Now, I guess the one place where I want to ask a question, and also maybe differ a little bit, is that I'm not sure that one needs to have PRD (price responsive demand) always saying, at every single price, "This is how much our demand will be." What you do need for them to say is, "At some security interruption price, this is the price at which I'm willing to be interrupted in an emergency to maintain the reliability of the system." But what that means, then, is that the ISOs, like suppliers in any other market (and some of this may flow to the competitive suppliers as well) have to be able to forecast what demand is likely to be at different prices in order to more efficiently operate the system. And we rely on Wal-Mart to do that, and keep their inventories at appropriate levels. It's something that ultimately ISOs and competitive suppliers will need to do as well. And I'm curious about where you guys are in that, and your thoughts about how you go about that going forward. As we see more of these automated devices that will simply adjust demand, either because their competitive suppliers are telling them, this is going to be a high price interval or a high price couple of hours, or because they're actually seeing something, as in New York, or Texas, where there is available information on look ahead forecasts from the RTOs, and they're actually responding to that information in real time. How do you see yourselves taking that into account in your operating forecasts going forward?

Speaker 3: Well, I certainly look forward to the day when we have that problem. The advantage that we will have is sort of the law of large numbers advantage that we have with wind and so forth. Right? The heterogeneity among folks will, I think, help us in this regard, where you're going to have literally thousands and thousands of customers, and on any given day their preferences might be a little different than they were the day before, but in aggregate, I would expect it to be reasonably forcastable as long as you have some history. That's exactly what we're going to be doing with solar, and that's what we currently do with wind. You know? Just give us some data. We can build a model. The error bands may be bigger. They may be smaller than they are for solar and wind. But I don't see why the same approach, factored into our current real time forecasting system, can't work. And, you know, I think practically it has to be at that level, because, you know, my grandmother's not going to be submitting a reservation price for electricity. We're just going to have to model it and commit the system. The hardest thing is going be getting the operators comfortable that it's really going to work like that. It's not going to be building the system. It's going to be getting them to say, "Well, I don't want to overcommit the system, because then you've got a whole other set of cascading problems. "

***Question** 7*: I just have a quick comment on the last discussion, and then my question. I thought it was interesting that ISO New England is prepared to charge generators a performance based rate, which I agree with, based on the loss of load probability. This is charging for the capacity prices to the generators, so that they respond. But the idea of charging and collecting the capacity revenue from the customers, based on whether they're in those hundred or so hours isn't on the table. And if you did that, you'd get the price of capacity more transparent in terms of its impact on energy prices. And I really believe the problem with why we're not getting as much of the demand response is because we're suppressing the prices and not getting these things in. And if you did those kinds of things, you would get the dynamic economic and efficiency changes, and I hope it's something that PJM will consider in its capacity market role changes. --

Speaker 2: In ISO New England, we definitely would like to go down that path. It's proving to be quite difficult. But, you know, I take your point, that given that we have a capacity market and that we are going to have to allocate those costs, how you allocate those costs matters a lot. The way we do it almost certainly does not do a good job of assigning the costs to the folks who cause those costs to be incurred. And, boy, I'd love to figure out a way to make that work better.

Questioner: My question as actually regarding the issue that you raised earlier about, "Hey, there's a lot of hours other than the scarcity hours when real time prices need to be better," and the question's really about how do we deal with getting those real time prices right in the face of lumpiness? I worked on a trade floor for an IPP for about 13 years and would constantly see how load reduction would come on, and prices would immediately crater, because there would be just thousands of megawatts of load response in an area. And you're in a scarcity condition, but prices are cratering, and I think there are times when it's working, but I think the majority of times, it's not working. I know our experience often was, we had a bank of GTs (gas turbines) that wouldn't run that much, but when they were called on, the operator would call on, say, ten 50-megawatt GTs. Well, the way PJM does its real time pricing is that they give each of them a little operating range, say 10%, but when they put on ten of them to meet load, 450 megawatts is going in at the bottom of the stack as a minimum load, and the 10%, maybe that's setting price in an interval, but much of the time they are getting paid uplift. And a third example is during the Polar Vortex generators being allowed to adjust their prices in real time if their costs went up, instead of in day ahead, or even being allowed to adjust their prices hourly. I think there are a lot of these little devil in the details aspects that we're sort of scratching the surface on that the commission, FERC, has recognized as, "Hey, this is a real problem." It's important to get price formation better. But I don't know that a lot of these are actually on the table to really get fixed in the detail level within the ISOs.

Speaker 4: Well, I think the conversation that's taking place in the MISO and the conversation that's taking place in ISO New England (I don't know whether PJM has had this conversation or not) about what's called ELMP (extended locational marginal pricing) in dealing with the lumpiness and the issues, is making a lot of progress. I would refer you, in particular, to the PowerPoint presentations that are on the ISO New England web page, because there's a very good discussion, and they go through all kinds of things about how this works and what the issues are. So they haven't implemented it, but they're talking about it quite extensively, and I think in a sensible way. And I think that as a theoretical matter, there are some computational issues here which are not trivial. But as a theoretical matter, we're pretty far along in understanding what we would like to be doing. But it is an education problem, because it's not completely obvious why this is a good idea. Although I do think it's a good idea.

Remember back in the day when we first started doing locational pricing, and you ended up with locational prices that were higher than the offer cost of the most expensive plant that was running--a lot higher. And then you had to go through and explain network interactions, and three of these and two of those, and substituting for that, and so forth. And this all makes sense. And it's the same kind of thing. You have to go through and say, "Well, yeah, here's what we're doing, and we're trying to minimize the uplift, and we minimize the uplift, and this is how it happens…" and you can explain it. It's not that it can't be explained. But you do have to walk through that process. So I don't think the conceptual problems…there are a couple of things that are still at issue that we can talk about, but I think mostly we're pretty far along. But it is a question of actually implementing. As you know, in the MISO, just a couple of weeks ago, they made the decision to delay, because people didn't understand what they were doing.

Speaker 3: But even in the MISO, they're not implementing ELMP. They're just trying to implement a hybrid GT pricing which is what New York did in 2002.

And I think the ELMP discussion actually is a recipe for going in and having these things take up another four or five years in terms of committees and discussions, where a lot of the issues I think are simpler in terms of, how do we get GTs to be setting price when they're actually on the margin? I mean, I think New York actually has solved that, and the other ISOs aren't able to do it because they use prices to send their dispatch signals, in contrast with New York, which sends dispatch signals and can go off into pretend land and figure out what the prices should have been otherwise.

Speaker 4: I'm happy to discuss this at length. As a matter of fact, at long length if you'd like. What I like to call extended LMP (ELMP)--the terms have been used but differently by different people. I'm thinking of minimum uplift pricing. The uplift story and its relationship to pricing is, for day ahead, clearly understood as a theoretical matter. And that's what we should do. It's a little bit more complicated when you talk about what you're doing when you're rolling forward in real time. But I think there's actually a solution to that problem, which hasn't been discussed very much, and I'm happy to talk about it. The problem with that theoretical ideal, which is a lot like LMP, is that it does present some computational and practical software difficulties in actually implementing it. And the way I characterize what they do in New York and what they are proposing in the MISO, is as an approximation of that ideal. It's approximate ELMP. And I think it's actually probably not so bad. But I don't think it's different. I think the measure of what it's a good approximation or not is against the theoretical ideal, and then how close do you come? And then what do you give up? And I think that's something where we've made a lot of progress in trying to understand it. And as I say, the discussion that's going on in New England is pretty advanced. Now it's a question of just doing it.

Speaker 3: This is a conversation that we have had in PJM. But I think we've sort of reached a different conclusion, first, because some of our uplift problems have not been with committing CTs. They've been committing with steam units for other purposes. And so that graphic that I showed you about how uplift has kind of just plummeted since the winter, is a lot of those steam commitments that we've cut out. And we're committing other resources to take care of reactive power and some of these other issues. So it's not as big an issue. But even with something like New York, or like MISO's approximate ELMP, there's still going to be uplift. I think Speaker 4 went to great pains to say *minimum* uplift. But there's now a mythology out there, and I think it's almost somewhat hidden in your question, that we can get rid of all uplift. And even if I let CT set price in the manner that you've talked about, now I'm paying part of those CTs uplift. I'm now paying other units uplift because now I've got to back them down when otherwise it would be economically rational for them to ramp up completely. So it's not free. Moreover, all of a sudden, prices have become higher. And I'm still paying uplift. Loads are going to figure that one out pretty quickly. And then you're going to have a food fight in the stakeholder process over this. And so, it has worked in New York. I understand MISO is going to go down that road, but they couldn't implement it because we just didn't have a whole lot happen this summer, so they couldn't really test everything to make sure. But we're never going to get rid of uplift. And so I think we have to just look at what kind of pricing mechanisms, first and foremost, work for making sure that pricing is consistent with dispatch instructions and operational reliability. Number one. First and foremost. And right now we do have a set of prices that do that. They may not necessarily minimize uplift. We'd like to get there. But right now we do have that set of prices. We've proven that they're equilibrium prices, and they are market clearing in a decentralized fashion. Until we can actually get to the point where we can solve a lot of the computational issues and make sure that we can get there with convex hull pricing or minimum uplift pricing, I think that we have to be concerned with that first. And we should try to get some of these other extra commitments out so that we don't have as much uplift, which is how we're approaching it.

Question 8: I love this discussion today. I just finished reading Walter Isaacson's book on Steve Jobs. And one of the fascinating things about Jobs is, they would bring him market surveys of what customers allegedly wanted, and he would say, "I don't care about that. I'm going to give the customer what they want, even though they don't know they want it now." And Jobs had a great track record of doing that. And any time we mitigate prices, or we try to manage prices or manipulate or shield the customer, we're basically trying to do that. We're trying to insert ourselves into what the customer wants or what we think they want, rather than giving them the tools to manage the reality of a commodity that has volatility and occasionally high prices. Or we're trying to shield ourselves as regulators from getting yelled at by politicians. And having been both a politician and a regulator, I think we'd be better served if as regulators we just did what we knew was the right thing to do, which is to go to all the way, free this market, and allow prices to settle where they need to in order to incent generation and resource adequacy, and let the politicians do what they do, which means that if they're yelling at you, well, then they can go back and tell their constituents, "I fussed at the regulator, because your price went up." That's my editorial comment.

My question is (and hopefully we can talk about this in the next panel and the one tomorrow) what is the role of bulk transmission in price formation? Because we assume a perfectly efficient system of delivery when we're looking at price formation, or we have LMPs that tell us we're going to get generation built in a particular place because the price is high. But I think we need to make some assumptions about what transmission ought to look like, what it does look like, and how do we incorporate transmission policy into price formation and resource adequacy, whether it's renewables, fossil, and response to 111d, or just in facilitating an efficient market.

Speaker 4: Well, this is a good question. I think the short run answer about how we deal with transmission in price formation is pretty straightforward, and we know how to do it, and that's what we're doing. I think this is a long run question that has to do with transmission investment and how we make decisions with regard to that. And I consider this to be one of these house of cards that's going to fall down in the not too distant future, and we're going to have to revisit what we're doing with regard to this. So I think it's actually a serious problem. It's not the highest thing on my agenda at the moment. People aren't talking about it as much as I think that they should. But I'm thinking of the cost allocation mechanisms under Order 1000, which you can't trust yourself to repeat with a straight face. And any time you repeat something, and you can't say it with a straight face, you're probably in trouble. Right? And I think that's an example of that. So I think it's a very good question. I think we have some ideas about that. But I think it's going to take a lot more investigation of what we should be doing and what we are doing. I don't know if that helps, but I think it's an important problem.

Speaker 2: I completely agree with that, and just would add that in New England, the current default mechanism for transmission upgrades and so forth that are not reliability based is--you almost couldn't design a better mechanism to ensure that no more transmission was built, because it requires essentially that the folks who are going to receive the benefits in some sense agree on how much benefit they're getting and allocate the costs accordingly. What we've seen is that that's a prescription for building nothing and going nowhere.

Speaker 3: In fact, I would even add on top of that, the incentive is to wait until you absolutely, positively need the transmission, so you can fob the cost off on somebody else, because it's a reliability project. So rather than the beneficiary paying, you wait. A lot of that is now changed with the transmission owners and PJM filing for a cost allocation mechanism that does recognize the so called DFAX method, or I'll call it megawatt mile for those who are familiar with the IEEE literature on this. But basically paying by, you know, who's got the impact on the line. But I think there's actually one on LMP that's actually troubling. And it might deserve some investigation. In some cases, the way we operate the system, knowing that we've got certain transmission assets, if the contingency occurs, I've got no place else for the power to go. I'm going to end up shedding load locally. And so we do that, but in pricing we have to relax that constraint a little bit so that we can actually make it solvable. The question is, if we have to shed that load, what's the value of lost load? It's large. Which means, then, the price of congestion there should also be large to get that signal. And right now, we don't have that in place. So I agree with Speaker 4 that we've largely solved this with LMP, but there are also some small practical matters that maybe we need to clean up. In the grand scheme of things, they're not huge like the transmission cost allocation issue or anything else. But I think we need to go down that road.

The only other thing I would add, though, too, is that we kind of have this strange way of allocating costs today. Load gets allocated cost, at least in PJM for the most part, unless you're a new generator, in which case, if you cause a reliability problem, you pay for all the upgrades. But incumbent generators don't pay for anything. And in some countries, in some markets, generation also pays for transmission, maybe not 50/50, but they do pay for some transmission. And a lot of it is by the DFAX method. So for example, in the UK, if you're a generator in London, you're almost getting paid as if you're creating transmission. And if you're a wind generator off of Scotland, you're paying for that transmission, because of the flows on the system. It's no different than Brazil, either. Brazil's got a similar cost allocation methodology. So does Argentina and Chile. So I think that there's something that we can learn from our brethren from around the world in some of these other markets on that.

Speaker 1: Let me just make a little bit of a different comment, not getting into the cost allocation, which is quite divisive and painful, that we are going through. My comment is about a change to some extent in customer expectations. There's always been resistance to transmission. Building in your backyard? No, don't do it. But now there's an increased amount of frustration among people that we haven't adequately exhausted all the alternatives. There's such a push—"Let's do more energy efficiency. Let's do more demand response. Let's do more local smaller solutions than build all these mega lines." So there's going to be an increased pressure on regulators to look for alternate ways of meeting customer needs. It's not like we can just run transmission lines willy nilly. It's going to be a higher hurdle than before from what we are seeing now, from the ground zero level.

Question 9: I want to reflect a little bit on two things that Speaker 3 had said. First, I agree that the biggest issue is, everybody wants the risk that they are willing to accept, and nobody wants any other risk. And then, second, to say that history really does matter. And I would say that if you look back to the 1978 to 2000 era, where the policy was that we should disaggregate development and operation of generation resources, I think that much of what has happened since then has kind of turned that on its head. So developers and generation operators, are supposed to be getting rid of gold plating and being able to, you know, have the lowest marginal cost for their units, but the quid pro quo was, they had limited exposure to certain risks. And I think at that time when you had PPAs such as in California, where there was a capacity price, where if you didn't perform, you didn't get paid, and that reflected the relative value of the product in scarce times, that that was very well accepted. But now it appears that generators are going to have to, for better or for worse, accept a great deal of risk for performance. And I wonder if the ISOs and the regulators feel any sense of responsibility to make sure that there are hedge products that match those kinds of risk, so that people who operate and who really did not necessarily think they were in it for real time pricing risk can hedge some of those risks? Because right now, the hedge products really reflect the lumpiness and not the liquidity that you'd want to best hedge your risks.

Speaker 2: Certainly risk is something we've talked a lot about in New England with respect to the capacity market. I imagine that's driving at least part of your question. And we wanted to make sure that there was risk in the market, not just because we like risk, but because that's what it takes to motivate folks to do what we want them to do. As far as making sure that the products are available, what we have the ability to do is make sure that the risks that we're imposing are the kinds that the financial markets can understand, model, digest, and then provide contracts against. We can't make that happen. We feel that if the kinds of risk that are being imposed on folks are of that nature, that the financial markets in a sense will provide, but I don't know how we could force that to occur. other than lay it out there, and then somebody on the finance side is going to go, "There are a whole lot of people who would love to offload some risk, and I think I can make some money there. And there's a critical mass to make it worth my effort to do that." I think that's a lot more likely when you have a market-wide phenomenon, than if it's just very idiosyncratic and one-off to the generators.

And the other point I would note is that in the current world, generators have some risk. But it's so idiosyncratic that, A, they may not have sought to offload that risk, but, B, you talk to the folks we've talked to in the financial community, and they say, "We don't know how to model it, and therefore we don't want to be a counterparty to that transaction." So, you know, I think relative to where folks are today, at least the steps we've taken in New England should actually improve the prospects of you having a liquid market out there to offload your risk. That's my hope.

Speaker 3: I was just going to agree with Speaker 2 on this. But I think what I'm hearing the questioner talk about is something that we're hearing in our stakeholder process as we go through this whole capacity market discussion, is that, "Oh, woe is us. We've got all this risk on us to perform now," and it almost seems like that performance is almost set in stone, and it's not. And so risk could be mitigated, not necessarily just through financial products, but also through the fact that there are things that can be done to make sure that those units are up and running, that when it gets below 20 degrees, you don't throw up your hands and go, "Oh, the pipes and valves are frozen." I mean, come on. Really? I just, it doesn't make any sense to me that we're looking at this as a financial product issue only, when there may be actually in some cases very simple fixes. Maybe actually testing the units on backup fuel. I'm going to be a little bit harsh here. Like I said, we've had several unit owners that had backup fuel that couldn't start because they hadn't run the unit for three years on backup fuel. Whose fault is that?

Moderator: On that I would like to thank the panel. I just think you did a great job.

Session Two.
Renewable Energy and Carbon Policy: What Exactly is the Relationship?

In the picture painted by its advocates and investors, investment in "clean" renewable energy is essential to reducing carbon emissions. That portrait, of course, constitutes a large part of what has led legislators and regulators to put in place Renewable Portfolio Standards (RPS), various public subsidies (many tax based), substantial ratepayer cross-subsidies, and trading regimes designed to further enhance the financial incentives for renewable energy. To what extent is the picture accurate? Developments in Germany and Spain that have seen increased reliance on renewable energy accompanied by increases in CO2 emissions have raised questions in the minds of many. Some of the questions being raised are: How does one measure the carbon footprint of renewables? Is it by the carbon output of the energy production process itself, or is it full cycle from manufacture through impact on dispatch? How should we account for the carbon footprint of the energy sources replaced? If renewables are part of a CO2 emission reduction strategy, should it be a broad based approach that simply promotes all forms of renewable generation without regard for the markets in which they are located (e.g. regardless of the coal intensity of a region's generating fleet), or should it be more carefully targeted on promoting more efficient renewables especially in markets whose carbon emission intensity is high? On a more macro level, is vigorous promotion of renewable energy a suitable alternative to regulation of carbon emissions, especially where the political will to regulate carbon seems missing? Where CO2 emissions are regulated, is vigorous promotion of renewables, through RPS or other means, compatible with the carbon regulatory scheme?

Moderator: Good afternoon. I want to thank Ashley for entrusting me to run the panel this afternoon. This afternoon's topic is certainly timely, because regulators and policymakers really are having to have the debate about what is it that we do to replace coal and at what cost? And further, what strategies and policies should our policymakers be engaging in? And that's exactly what the gentlemen sitting next to me are going to be broaching into and we're going to delve into that discussion and I suspect I've already had some inkling it might be some lively discussion as we move forward.

Speaker 1.
Thank you very much. I hadn't intended to talk about the paper that I did for Brookings, but rather to do what I was asked to do which was to answer a particular question. I might rephrase it a little bit differently than it was in the draft agenda that I was sent. But basically the question as I understand it, is, can renewable incentives substitute for carbon regulation? The idea being that renewable incentives are more politically easy to implement, whereas carbon regulation, and I'm going to define what I mean by that, is a lot more difficult.

First of all, to define what I mean by renewable incentives, I mean, first, in the United States, Renewable Portfolio Standard and renewable energy certificates, tradable or not. Secondly, I mean feed-in tariffs. And thirdly, I mean tax benefits including production tax credits, and investment tax credits. These are all renewable incentives. There may be others, but these are the main ones. In Europe, it's mostly feed-in tariffs, although there are some renewable portfolio standard types of policies, but they focus a lot more on feed-in tariffs in the United States. I think PURPA kind of soured people on fixed price contracts for renewable energy. So that the focus has been on Renewable Portfolio Standards. And in the US in particular, tax benefits seem to be very, very popular.

What do I mean by carbon regulation? I really see three different categories. One, a carbon tax where the government sets a price for carbon and the market determines the quantity of carbon to be emitted at that tax level. Secondly, a carbon price through cap and trade, where the government sets a fixed level of emissions and allows the price of carbon to be determined by the market. And then there's the third type of carbon regulation, which is epitomized in the recent EPA proposed regulations, one having to do with new stationary sources of carbon or greenhouse gas emissions in general in which a proposed regulation seems to me to be rather draconian because basically I find it hard to believe many new coal plants will be built to meet the new stationary source requirements, and none can be built without carbon capture and sequestration, which is very expensive and relatively unproven. The 111(d) standards, however, seem to me to be a lot more flexible, and they focus on things that I think are more realistic, like improving the efficiency of coal plants and substituting gas production for coal production. Those are the two first building blocks. The third building block is the renewable incentives and the fourth is efficiency, and we heard a lot about demand efficiency this morning and there's still a long way to go before the market really accepts demand management in a meaningful way.

Now, there are some problems with renewable incentives. One, they can cause unnecessary increases in capacity. Secondly, capacity increases may not be justified by energy savings and CO2 emission reductions. Thirdly, if renewable energy displaces combined cycle and natural gas or nuclear rather than coal, there's very little emission reduction. Renewables provide little system benefits and may generate substantial system costs. And they are not technology neutral. Now I'm going to go into each one of these a little bit.

I did a comparison for Germany, Spain, the UK, and the US. And I said, "OK, what's happening to generating capacity and what's happening to wind and solar capacity?" And you can see from this table that in Germany, more than 100% of the increase in capacity between 2007 and 2011 has been wind and solar. In Spain, it's 80% of the increase in capacity as wind and solar. In the UK and the US, it's roughly 50%, the balance being mostly natural gas. But you can see that basically most of our capacity additions in the US and in Europe have come about through wind and solar.

If you turn to the next slide, I compare generating capacity increases versus electric consumption between 2007 and 2011. You can see that in Germany the capacity went up 18.8%, whereas consumption went down by 2.3%. And in general, across all of these jurisdictions, there's been a rather large increase in capacity and a reduction, rather than any increase, in demand. Now if that's true, how do you justify that increase in capacity? You can justify it saying that, "OK, there's been a savings in energy cost because of the new wind and solar capacity, and there's also been a reduction..." You can argue there's been a reduction in emissions.

But if you go to the next slide, and if you value those savings in Germany, Spain, the UK, and the US, depending in the first part of the table, we assume that you displace coal. The net benefits of wind and solar in terms of reducing emissions and saving energy (and we priced the emissions at $50.00 a metric ton) is negative. So you can't really justify that increase in capacity on the basis of emission savings and energy savings. It's hard to justify it on the basis that you need capacity for reliability, because first of all, demand's going down and capacity is going up. And if you displace gas combined cycle rather than coal, we see that the net benefits remain negative. And the interesting case is that in Germany, Spain, and the UK, it makes relatively little difference whether it displaces coal or gas, and the reason is simple--gas in Europe is around $10 or $11.00 a million BTUs whereas in the US it's \$3 or \$4.00 per million BTUs, and therefore, the energy savings in Europe are very substantial and counterbalance the lower emission savings when you displace gas.

Now I will refer to the paper that I did at Brookings, because one of the things I didn't do in the paper was really analyze the system benefits and costs of renewables. I got criticisms of that paper on both sides. Mr. Amory Lovins who some of you know, attacked me on the grounds that I got my data all wrong. And others weighed in in the same vein, whereas those on the other side of the divide criticized me for not taking account of the real systems costs of renewables. Wind and solar capacity contributes very little to system reliability, particularly with high penetration. And most worrisome of all is that high wind and solar penetration can cause premature retirement of nuclear and fossil fuel plants, because, particularly with nuclear plants, you have a high fixed operating cost, plus you have continuing capital cost to improve the capacity. And wind and solar, which come on at zero marginal cost during off peak periods, can force either nuclear to shut down or the electricity produced to be spilled and not utilized. So the effect of wind and solar production, particularly through the wholesale pricing system, can be to cause premature retirement and also make it very unlikely that a lot of new investment in highly efficient baseload plants is likely to take place. I didn't take into account in my paper either that wind and solar may require substantial investments in transmission and that they can impose serious cycling costs by increasing maintenance costs, reducing energy efficiency, and increasing CO2 emissions of fossil fuel plants that have to go up and down and operate at levels that are not most efficient from the point of view of fuel use.

Renewable incentives in addition are often technology biased, favoring solar over other renewables. Or favoring offshore wind, for example, in the UK, rather than onshore wind getting more incentives. They normally exclude other no carbon alternatives, for example, hydro and nuclear (except in some cases small scale run of the river hydro). They do not really provide for increased fuel efficiency, either in gas combined cycle or super critical coal plants, and they're not really designed to minimize CO2 emissions. The Renewable Portfolio Standards are designed to increase the output of renewables, not to maximize the reduction in carbon emissions. On the other hand, carbon price regulation is technology neutral. (I'm talking here about either carbon price through carbon tax or carbon price through cap and trade.) They can achieve emissions reduction by marginal dispatch changes. You don't need new capacity increases to reduce emissions. You need to switch from coal to gas at the margin and the higher the cost of carbon, the more you're going to utilize gas in the dispatch than you are going to utilize coal. You can achieve the lowest-cost CO2 emission reductions in both the short term and the long term, and you can combine that with some internalization of the system cost. My basic conclusion is that renewable incentives are simply not a substitute for a carbon price, either through a carbon tax or through a cap and trade system.

Question: When you were doing all the price and cost numbers, that was taking into account the incentives. Is that correct? The analysis was looking at the investments that are made by states or federal government, etc., and comparing those to the benefits. Is that right? I'm just thinking about your net benefits. The net, it's net of the costs of the state and federal incentives?

Speaker 1: No, no, no. It's void of any subsidies.

Speaker 2.

Thanks, and thank you, Bill, for the invitation and for what role you've played in catalyzing these kinds of conversations that we have here. It's also just great to see colleagues in the room.

It's great that Speaker 1 went first, because the way you ended on how renewables are not a substitute for a carbon price, I would completely agree with, especially when you think about this on the state level as well, because a Renewable Portfolio Standard, or other kinds of incentives, in addition to potentially getting carbon benefits (which I understand your study shows not. We've showed that we have in this state. I think it's very jurisdictionally specific.) can also serve other state goals, whether they're clean energy, job growth, savings for municipalities, etc.

I want to flip around that finding, and that is that a carbon price by itself I don't think will reach those kinds of goals as effectively and efficiently. I was at a carbon pricing side meeting in New York last week during the summit and it was all about pricing, and coming from a state, I realized that it's not all about pricing. I think pricing is a fundamental piece. As many of you know, Massachusetts is a member of the Regional Greenhouse Gas Initiative (RGGI), a cap and trade program amongst nine states. And so that, effectively, has set a price. But I want to talk at some length about complementarities as well.

One of the first things that Governor Patrick did was integrate energy and environment. He took all of the energy agencies which were in disparate secretariats and put them together under one secretariat, the Executive Office of Energy and Environmental Affairs. And that way, solving most of the complicated problems that we face now can be done with a comprehensiveness and an integration that I don't think has been done. And I think the federal government is still struggling with that, with EPA and DOE and FERC all figuring out what their roles in this new world of a carbon-constrained economy which I know there's some debate about, but there are many of us who think that there is no debate about it. We need to be moving into a carbon-constrained economy. I think at this point to be talking about electricity and all of the myriad complications, whether it's the real time markets or forward capacity markets or energy efficiency…to do that not in the context of this new carbon-constrained world that we're in does a real disservice and does a disservice not just to the policymaking community but to the academic community, to the consulting community. It's really hard to imagine moving forward in any kind of decision-making capacity where energy, environment, and economy are not taken together.

So the first step is to bring together energy and environment and economy. The second step would be integrating the right price signals with complementary policies at the right level. And in a way linking global climate change with local implementation, and whether there's a cost or benefits, those have to be taken into account. So at the same time that we launched RGGI and the same time that we joined RGGI, we also launched a whole suite of new or enhanced already-existing policies, and I think if that had not been done, we would not see the kinds of results that I'm going to talk about later. So we decoupled. Even in a world in which the price of carbon is right, if the utilities don't have the right incentives for their bottom line to invest in the kinds of infrastructure for energy efficiency and renewable energy, etc., you're not going to get the robust kind of change that you need. We do have a RPS program and an SREC (solar renewable energy credit) program, which admittedly shows our policy is not always technology neutral, and sometimes there are really good reasons for that. I think that again it's a layering of a carbon price technology neutral policy with some incentives that are tailored to a specific jurisdiction. We have our own net metering rules that have come with all of the pain and heartache, maybe not as much as in Arizona, but a lot of pain and a heartache as well, as we try to get those kinds of incentives correct. We've worked very closely with the ISO on getting the markets right, trying to figure out how to get the right market signals so we incorporate the externality that is seen in carbon pricing in a fundamental kind of way. We've done our own version of energy efficiency incentives, long-term contracts for renewable energy. Again, if you have a very strong price on carbon but developers can't get financing because the markets fluctuate and they need a long-term contract, that's a tool that potentially can be used. We've worked really hard on our state permitting for these facilities. So totally different agencies are engaged with this. How do we get anaerobic digestion, which was treated as essentially trash in the past and so therefore could never be sited locally? We figured out how to do that in a way that's sensitive to the local municipalities but also sends the right signal and a certain signal to the developers and financing all kinds of innovative financing. Again, solar would not have grown the way it has if we haven't come up with interesting ways to finance to get beyond this capital requirement at the beginning.

Funding for innovation. So thinking about this in a much more comprehensive way, Massachusetts is, in particular, technology strong. Let's provide seed funding, catalytic funding for the valley of death for the problems of upfront investments that usually a company won't take because they're too risky. And then municipal engagement--I can't speak enough about how important that's been. When municipalities have a solar landfill, put solar on their landfill, have turned something negative into something positive, and are saving $200,000 a year, suddenly addressing climate change is a great thing. And that's important. That's a link that's important.

And then we've had to link very closely with our PUCs, something that I think most environmental efforts don't do.

So each of those are complementary. None of them have an explicit price on carbon but not doing any of them would set up roadblocks to doing carbon reduction as efficiently as we could. And a really important part of this is communicating this. I'm not going to bore you with this YouTube, but on the summer solstice, I combined with our commissioner of DOER, our energy agency, and we traveled from sunrise to sunset at solar installations on landfills and superfund sites from Chatham at 5:08 in the morning to Pittsfield at 8:30 pm to demonstrate the kind of big benefits and cost savings and greenhouse gas reductions we were getting from many of our projects. And by communicating this, you get more and more companies and more and more municipalities saying, "This is something we want to take advantage of."

So I'm very quickly go through a bunch of graphs that just show our results. We have a Global Warming Solutions Act which requires us to go down to 25% below 1990 levels by 2020 and we're moving forward pretty quickly already on this. And that's primarily from fuel switching from coal to natural gas, but also a big chunk of that is from energy efficiency and renewables. And we're legally required to get to 80% by 2050.

No question, if you're an economist here (as I was taught by the excellent economists here), when you do something like cap and trade and you auction off the allowances, there's going to be a transfer of those revenues. The negative red line on this chart is generators who have spent over a billion dollars on allowances, and those revenues have gone to the states and been plowed into energy efficiency programs, rate relief, those kinds of things. And in general, the region has garnered net benefits of between $1.6 and $2 billion since we started the RGGI program.

This is an ISO graph. The blue line on top is projected electricity demand. If we stopped our energy efficiency programs now, the red line is projected demand. If we just did what we have on the books three more years, the black line is if we continued in the trajectory of investments which are now up to about a billion dollars a year in energy efficiency. And just from a cost perspective and a capacity perspective, that's equivalent of I think about 2,000 megawatts. So that's a lot of capacity and associated transmission that's not needed because of our investments in energy efficiency. And just if you look at those far bars over there, the blue line is our investments in energy efficiency over a three year period. That's our authority. We regulate over a three year period and there are big benefits and net benefits. Huge benefits that come out of this. So in our conversations that we've had with other states, particularly coal states or states where electricity is very cheap like Oregon, we even find these kinds of benefits, whether this is a carbon policy or a jobs policy.

We're up to over 600 megawatts of solar. The cost of solar, this is just I think at 13 month period for some particular kinds of installations dropped by 40%. So we're already seeing solar approaching grid parity.

Wind, we've seen a similar increase, but leveling off because of some of the local siting issues. And this is data that just came out on Monday. In the clean energy sector we've seen job growth in the 10% range in the last three years--almost 90,000 workers, and this cuts across, from the Ph.D. folks innovating new PV panels, to architects, to plumbers, to electricians, to those developing the newest car batteries, etc. And just to show this in a very visual way, the yellow dots are solar installations in 2006, 7, 8, 9, 10, 11, 12, 13. Huge change. Huge change in individual and business behaviors. Huge change in what the impact is and then what we've seen in general, and I'm not making any claims as to drivers. But we've seen in the state an increase in our gross state product of 70% since 1990, and a decrease in the power sector greenhouse gases of 40%, and economy-wide of 16 to 18%. So certainly we've seen robust economic growth at the same time that we've put in place a whole suite of renewable, clean energy kinds of programs that are getting the greenhouse gas benefits that we're looking for. So why don't I stop there?

Question: Can you tell us the reductions in greenhouse gases associated with the recession versus your efforts? And secondly, how much of the reduction is simply substituting cheap natural gas for coal?

Speaker 2: A great question. There was definitely a decrease in the recession. We saw a rebound in the economy earlier in this state than in other states, and we didn't see a rebound in emissions. We saw a trend in emissions continue down. But there's no question that the recession had an impact. There's also no question that the majority of the greenhouse gas reductions that we've seen have been from switching, driven mostly by the market but also driven by our most recent greenhouse gas policy. So we already had on the books some carbon policies, etc. So no question that was the majority of that driven. I'll go back and double-check, but I think it's 25 to 30% we could tag to new renewable energy and energy efficiency. And we think we're going to see that energy efficiency just growing, because we've just started those investments.

Question: In Massachusetts, what is the division of greenhouse gas emissions from transportation versus energy?

Speaker 2: Transportation is about 40%. So not dissimilar to most parts of the country. I think nationally its 30% to 40%. So 40%. I think 30% is roughly buildings. So you can think of that on the solution side as efficiency, and 30 plus percent is in the electric generation, heating, etc.

Question: Have you had the opportunity to figure out what the cost per ton of CO2 reductions are via the program, and not counting the subsidies that have been directed toward renewables?

Speaker 2: A really good question. I don't know exact numbers, but I do know our solar program would be the most expensive of our programs. Energy efficiency would be a benefit. Essentially, it's costless, because we're seeing big benefits on that side. And that's totally consistent with the McKinsey studies and stuff like that, if you look at the left side of the graph where you're getting savings. Wind, at the beginning of our program, was costly, but now, especially since we've done this long-term contract programs, wind is coming in at market or below market.

Question: In the list of initiatives that are being undertaken in Massachusetts, if you had to pick the two or three most important pieces, which of those pieces would you say are the most important?

Speaker 2: No question, the energy efficiency programs. No question that what we call least cost procurement, or the requirement for utilities essentially to procure energy efficiency before generation as long as it's cheaper, and the associated public process that goes along with that. And the ramping up of RPS program, if there were two I had to choose. But I want to choose those other complementary ones. Joining RGGI. That would be my first, because that sets the price and that's a fundamental piece here.

Speaker 3.
Thank you and thank you for having me. It's great to be back. I used to spend a lot of time here when I was at FERC working on standard market design (which someone here says made history back then). So I guess we accomplished something. But I also agree that we can say, "We told you so," because it's effectively in place in most of the country.

I'm going to go through some of the questions that were asked. First, I want to thank Michael Goggin, who is responsible for a lot of the material I'm going to present. I've had the luxury of working with a lot of great industry experts and I found none better than Michael. So he's responsible for a lot of what I will show.

On the macro question here, can renewable energy incentives replace carbon regulation? I say yes. He says no. So there's a significant debate, but I do want to clarify maybe some areas where I think most of us probably agree, so we can figure out where the debate is and is not. Number one, I think both of these papers are in the framework of finding the value of power sources and replacing, as Dr. Joskow has advocated, the overly and perhaps crude and simplistic levelized cost of energy (LCOE). I think both of these are efforts in that valid effort to be a little more careful about the actual value of power sources. So I don't think we disagree on that. There's a policy principle here that one should price the externality and that you should have efficient markets and price the externality, but do maybe no more and no less and don't run rampant with incentives everywhere, but let's focus on the market failure and fix it and the markets.

There's a market design principle that gets into some of the papers, and certainly the morning panel, that markets should be open, competitive, technology neutral. I don't see a need for FERC tariffs to identify wind or nuclear or other sources specifically. Let's have well-designed markets and get the prices right so they're open, transparent, fair, and allow all supply and demand sources to compete fairly.

So those are some general principles and I'm not going to argue with those. I am going to argue quite a bit about the data and assumptions used, and therefore, the results of these papers, particularly Speaker 1's papers. Although, again, I think these are both useful contributions in terms of getting us past LCOE, and there are some useful and I think valuable contributions on methodology. I'm not going to spend as much time on the methodology. It's really more about the data, and I say that with some trepidation. I don't want to bore you with just a data dispute, so I'll maybe move through those quickly, but get to discussion about the ultimate conclusions on renewable incentives versus other approaches.

So I'm going to make these sub-claims. Wind energy significantly and cost effectively reduces carbon emissions. I think that's not what all of these presentations say, and I want to make that claim and demonstrate it. I think there are a couple problems with each of the Speaker 1 and Speaker 3 papers in the terms of the data and a couple of assumptions, and if those are corrected, I think the above claim holds. And, finally, clean energy tax credits are efficient carbon reduction policies in the absence of a carbon price. So, again, I'm not going to dispute that sort of one should go with the first best. Internalize the externality, a carbon tax in theory is the right way to go. When others say, "Well, but other incentives may be far less efficient," I say, "Well, they may be. They may not be." So let's look at the numbers.

So here are some of the foundational facts on wind energy. 62 gigawatts of operating capacity. Obviously that has risen quite dramatically in recent years. Texas is the leader. You can see the darker states where the wind generally is, and that's very important. I'm going to get to that in a second. Cost trends are very important. They have been falling very significantly, in the range of 50% in the last five years. You see the PPA prices. These do take into account the tax credits. You can add a little over $20.00 on to some of these to see what they would be without a production tax credit. But--and again recognizing that LCOE doesn't have all the information you'd like it to have--it is useful, I think, to see what most market analysts are saying. This is Lazard's numbers showing wind very cost competitive relative to other sources now. I think PV is similarly coming down quite a bit, and just for reference while we're on this slide, you can see the wind PPA costs. If you add the PTC, you'd be in the $70'ish range and Speaker 1 has $124.00 per megawatt hour, which is, I think, widely outside of where the market is right now.

Now, next, I mentioned the geography. And as Speaker 2 said, let's look at the power system in terms of where we are in a carbon-constrained world, again acknowledging that some renewable deployment may make a big difference on carbon and others may not. The first thing you need to do is to look at the geography and the time of day of the output of what you're putting on the system and see what you're displacing. So it turns out for wind, luckily, I guess (and maybe this is true in the US and maybe not so much elsewhere. I don't know.) If you look where the wind has been deployed, it's actually displacing a disproportionate amount of carbon off the system. It's displacing a lot of carbon. Through the Midwest, people think of the kind of the rural red agricultural states where the wind blows most strongly and there's quite a bit of carbon on those systems, Texas included. And wind is displacing a lot of carbon right now.

I'll keep moving through on the data. Just to illustrate that last point, if you look at the green boxes, in fact, the top line in MISO in the upper Midwest, 85% of wind megawatt hours are displacing coal in that area. You can see the other boxes. But it's a high amount. SPP, MISO, interior west PJM. And there are, I believe, multiple goals for deploying wind and renewables, but if you're solely focused on carbon, you want to be putting it where the high carbon output is. That's what you're doing with wind. Just take a quick glance at Europe. There's been a lot of debate about this, so I just wanted to reference it quickly. Yes, countries added a lot of wind. They reduced their carbon quite a bit. Now some other factors have intervened in recent years, namely, what Russia is doing to gas prices and what Germany did with nuclear plants and some new coal plants coming on in Germany. So there are a lot of other factors in here. So I'm not saying that there's a direct one to one correlation.

I do want to talk about this one. Speaker 1 mentioned the cycling cost and this is, I think, a great thing for this group to look at, because this group, if it stands for anything, it has been to look at how the grid actually operates and price it and operate it efficiently. So one could say, if one knows nothing about the power system (and we, of course, hear this all the time) that if you put a wind generator at your house and you were disconnected from the grid, you might have to have a little gas plant there backing it up 24/7. That's true. But almost everybody's on the grid, and so let's look, and it turns out there's a lot of experience and a lot of studies where you can show what the cycling costs actually are. PJM recently did a study and actually said, when you get to 30% wind, the cycling costs on that grid actually go down. And that's because you're not necessarily cycling every coal plant on and off. You may be just not committing them for a week or a longer period of time. It depends on the particular grid, what technologies you have on that grid, and how that grid operates. So you can't assume that cycling costs go up.

The NREL analysis on this slide shows that 33% renewables, you get 99.8% of the expected carbon emission savings as you would if you left out the cycling issue. So it's an infinitesimally small number in that western study.

One can quantify all these costs and benefits. I have a slide here. Obviously the results from other panelists come out differently, but it would be great to sort of put all our numbers together and maybe run through the same model. I don't think it's all that interesting to debate the numbers if we're all using different assumptions. But these are our numbers. $102.00 a megawatt hour. Gross benefits of wind using the ERCOT data.

So, some more specific issues that are in the papers. Again, the overall framework of valuing different power sources is fine. Some of the methodologies are generally OK. The inputs make a huge difference, particularly the capacity factor. So that's the biggest one. Wind cost inputs are also high in both cases. As I said, they're coming down a lot and are much lower than assumed. Also, capacity value showed up as a significant issue in the paper. Well, I think everybody knows here. Capacity prices are actually not very high in most of the country right now. So that shouldn't affect the value that much, at least in the US. I know Speaker 1 is looking at other countries as well. And then wind integration costs are low and, in fact, are lower than most conventional sources. Again, you can look at the system operator studies and experiences on that. It can be measured. You can't just assert or assume that they're necessarily higher or lower. If I were a system operator, I'd rather deal something that gradually goes up and down over a two-hour period than losing 1,000 megawatts instantaneously. Not that there's anything wrong with those resources, and that's why we have both capacity and operating reserves, and that's fine. You can price it all out, but again, one shouldn't assume that just because one resource regularly goes up and down that its cost is necessarily higher.

With respect to Speaker 4's paper, the main thing that I think affects the results (and no fault of his for using the data that were available) is that these data have changed dramatically because, as a lot of folks know, there were significant negative prices in a few locations in the country. You had sort of a timing mismatch with wind being developed before the transmission lines were there. Barry Smitherman did one of the best things that's happened and took one of the most economically valuable actions in building what's called the CREZ Lines in Texas. They're paying for themselves, not just for wind but for all resources. Once those lines were energized, the negative prices essentially disappeared. And so you can see that on that curve, that graph. So if those recent numbers were taken into account, a lot of the costs that went into Speaker 4's numbers would change significantly.

And then a couple points on Speaker 1's paper and I will try to wrap up quickly. The biggest one is the gas capacity factor. Gas combined cycles don't operate around 90%. I don't object to using a number in that range for capacity value because their availability is in that range. But if you're looking at the value of displaced energy and that's where a lot of the results are driven, you can't have gas combined cycles operating that much. I mean it should be under 50%, or EPA's looking at getting up to 70%. Maybe they can. 90% is way out of the range. Second is the wind costs, and I talked about this, but using 2,200 versus 1,600 changes the results pretty dramatically. He mentioned Amory Lovins had a number of other data disputes. When you incorporate the changes that Speaker 1 agreed with from Lovins' critique, the difference between wind and nuclear shrank from $343 to $122--by two-thirds, so there are significantly changing results. So the results are not very robust when you start incorporating even just a few of these assumptions, and if you do just the wind cost and it's O&M in construction times, you change the wind net benefits from negative $30,000 megawatt a year to plus $80,000 a megawatt year. The point being that the numbers change all over the map once you change a couple of these assumptions and these assumptions and numbers are well documented in the markets. I think that's probably enough given the time on that.

There is just a note that there are two other efforts that are relevant if both of these papers are efforts to do what Joskow recommended of valuing alternative power sources. EIA and Lawrence Berkeley National Lab, both made such attempts as well, which are very useful where you do take into account, for example, the time varying nature of the energy sources of winds operating at night and the costs are lower. That's taken into account in capacity value and those sorts of things. And the levelized avoided cost of energy is a metric they use which essentially you can think of as a ding on an adjustment factor on wind. It's in the range of 10%. So if you wanted to kind of go back to the levelized cost of energy numbers and give wind a 10% ding based on those factors, that's sort of fair according to those analyses.

And then let me jump to the policy implications here. When you take a lot of these factors into account (and, again, let's assume our goal is a carbon constrained power system that operates efficiently and where carbon price may be sort of the first best policy in order to do that and provide the right incentives for supply and demand) I think the debate is really, are some of these incentives second best policies or are they 23rd best? And I will admit there are policies out there and in other countries that are maybe closer to the latter. I would argue that the production tax credit is very close to second and, in fact, a very close second. I would argue it's first, but the economist in me wants to not even make that claim. But the reason is that, taking into account again the time it operates and the geography, you're putting a lot of carbon free and zero marginal cost energy in the places where you're displacing carbons. So the result, is--and you can measure it--you get $12.00 a metric ton. That is what the PTC is getting, and then for tax policy purposes taking into account the overall societal distortion. So reduce that down to $3, .25 marginal excess burden. And then again, sort of back to the bringing it back up a level to the principles, I think we all agree that the power system should have a level playing field where all sources compete and carbon free electricity is appropriately valued, and I would assert that in the market without a carbon price, an alternative policy is needed in the interim, including with 111(d) which starts in 2020 and we've got five years to go and we shouldn't let the perfect be the enemy of the good and let's do something that's efficient and second best, granted not the 23rd best. Tax incentives can be efficient, can also be technology neutral, and I reference the Senate Finance committee, Senator Baucus's technology neutral tax credit proposal that I think is going to get a lot of attention and discussion next year in the tax reform process. They can also be market based. Renewable Portfolio Standards are market based. PTC is market based. I think both authors here have noted that sometimes there are restrictions on the market functioning which can create inefficiency, but they can be market based.

Question: There seems to be a tendency of mixing up capacity and energy in a lot of these presentations. So you see megawatts or gigawatts of capacity, and the comparable important number is the energy used. Speaker 3, you did get into that. But, Speaker 1, I didn't see that much in your presentation at all. And that gets to be very difficult to get your mind around. It's a very, very important metric. But the question I had for Speaker 3 is, one, you said the capacity value is not very important because it's not very high. Well, in the Northeast it actually is very high. You probably know that and it is very important. Later on you said night versus day, the differences are captured in capacity values. So that's OK. I'm not sure how those two points wrap together. Then I guess the final real question was that you said, I believe, that 90% capacity level for combined cycle plant was unrealistically high. And I wonder if you were saying that based on the ability of the machine to run at 90%, or the economics?

Speaker 3: Just the way they're dispatched in power systems. They never get that high on an annual basis. And again, I said, as a capacity value, they should get that, based on however the system operator wants to measure capacity, but that's an availability number, and they are available and capable. I don't disagree with that. I just think if you're trying to estimate how much emissions will be displaced and how much electric power energy markets will be displaced, and price reductions as a result, you should use the number based on how they are actually dispatched.

Questioner: Look, I want to agree with you guys since I'm on the renewables side. But a good combined cycle plant will have a 99.5% availability and in many systems will, in fact, run at 80 to 90% capacity factor because with the price of natural gas where it is, there is an economic justification in the dispatch cue to run them at those high levels.

Speaker 3: I'd love to see that plant. I think the national average is under 50.

Questioner: The national average may well be under 50.

Comment: There are several things you need to take into account when looking at capacity factors. Number one is that when you're doing a cost benefit analysis, you're looking at a new, highly efficient, combined cycle gas plant, whereas the existing base that we have combines very efficient ones and very inefficient ones, and the average of those is not a meaningful number to do the cost benefit analysis. Secondly, one of the reasons that the capacity factors for gas are not higher is simply that (except in RGGI) throughout most of the United States, there's no price for carbon, and that biases output towards coal because coal is today cheaper than natural gas. So what I was trying to say is that if you brought in a new, highly efficient, 60% efficient gas combined cycle facility and you didn't have a lot of wind and solar cutting in at zero wholesale price, you could run these things at 80 to 90% of capacity. So that's really all I was saying.

Questioner: Well, I don't want to extend this but I think in your comparison between gas and coal, you would also have to look at the embedded age of the coal fleet which is 40 to 50 years versus the embedded age of the combined cycle fleet, which is nowhere near that and compare the heat rate of those average units, and

I think you'll find that in many regions, the cost of natural gas fire generation is, in fact, cheaper than the cost of coal fired generation. And that fact is actually illustrated by the results of I think it was the first quarter of this year where you have more gas fire generation than coal for the first quarter in history.

Question: I have two related questions. On your slide titled "Wind Cost Trends," there's a chart about average wind purchase price. And my question is, do you know how those prices were derived or from where?

Speaker 3: Those are from power purchase agreements, contracts that are on file with FERC.

Questioner: So they're contract prices, not based on the clearing prices in organized markets.

Speaker 3: FERC had a chairman named Pat Wood who wanted transparency in the market and he required those prices to be recorded.

Questioner: The other one is about the slide that's titled "Wind Concentrated in Carbon Heavy Regions." Is that just 2013? Is that a snapshot?

Speaker 3: The EPA has a tool on their website. I think anybody can just get on and plug in resources into that and see what is displaced or not displaced. It's hourly by region.

Questioner: But I guess my question is how does that adjust for an organized market low gas prices in terms of what displaces what?

Comment: Yes. This is based on 2013 fuel prices. The EPA tool has up to 10 years, I think, going back, of historical dispatch patterns for coal and gas generation. We ran it for 2010 as well as a test and got near identical answers, with gas prices being significantly higher in 2010. So obviously it makes a difference. If you have extremely low gas prices where gas is being dispatched before coal, as long as gas is generally dispatched above coal, the results are relatively consistent.

Question: That table shows a really impressive decline in purchase prices of about two-thirds in a four-year period. And we've heard a lot about solar and its decline in dollars per watt because of the sort of manufacturing costs fundamentals. How much of this figure is being driven by that, versus people who've simply ended up oversupplied or overstocked with wind turbines that they find that they need something to do with?

Speaker 3: Most of it is, I would say a technology and manufacturing operations story, including doing a lot of that here in the US and these are expensive and heavy to import, are the main factors. I would not put a lot of stock in 2013. I think Speaker 1 and others know there were only 1,000 megawatts deployed then. So I wouldn't put too much in any particular year and there probably is some of the latter factor in that last year, with supply and demand factors affecting that price.

Question: I'm still trying to figure out this chart on "Wind Costs Trends," the same one that the two previous questioners were looking at. These are prices without the incentives? Or are these with incentives?

Speaker 3: These are actual contract prices. So therefore, they effectively include the incentive. You can raise this number by the amount of the PTC, roughly $20'ish a megawatt hour. It's only for 10 years. It's not exactly that.

Speaker 4.

I have to say I was very surprised to have Speaker 3 discuss this paper of mine in the context of the assertion that wind energy significantly and cost effectively reduces carbon emissions, since I didn't discuss cost or emissions in the paper. So it's true. It did not change that statement in any respect. I do want to say a couple of things though in response to some of his points before I go on to my main presentation. The 10% ding for sort of producing more at night than in the day is about what I got. But what I also found by looking at individual units is that there's an enormous variation and, in a way, that's a core point of the paper--that to the extent that Renewable Portfolio Standards constrain siting, they can impose enormous performance penalties. The difference between the Gulf Coast of Texas, where plants actually get a premium for when they generate, and west Texas, granted before the transmission was built, is just enormous. That revised version of that paper is up on our website. I believe it's up by now. If not, I can send it to you. It's forthcoming in the Energy Journal next year.

The other thing I do want to say before I go on to this topic is about the negative price stuff. First, it's not an ERCOT phenomenon, at least not in 2011. It's everywhere, except New England where prices were in effect constrained to be non-negative. So most wind generators saw negative prices for a substantial number of hours and generated more when prices were negative than when prices were positive. That's not a criticism of wind as a technology. That's a criticism of a policy that doesn't discourage generation that has negative value.

So let me talk about what I was prepared to talk about. As the academic here, I thought I'd give a very academic presentation and take the long view. And the long view gets you to about 2050. We talked about the need to reduce carbon emissions. And if you sit back and say, "OK, suppose we take climate seriously," which I think at least many of us do, and you take the notion seriously that you've got to make substantial reductions in emissions while growing the global economy, how do you do it? Well, that's a carbon emissions flow chart for the US, but it points in the obvious directions. You rob banks because that's where the money is. You look where the carbon is, and the carbon's in electricity. The carbon is in transportation and a bunch of it is from industrial and other sources.

So the obvious notion is, you want more efficiency. You want to think hard about transportation, and obviously you target electricity. OK. How do you do that? Well, there are a lot of studies that look at how you might get there. The one I happen to have handy is a recent one by the International Energy Agency. So they ask the question, what would a least cost scenario to 2050 look like that makes the kind of emissions cuts that are associated in policy discussions with a 2 degree centigrade ceiling? We don't know what would give us 2 degree centigrade, but there is this discussion. And as you would expect, what happens? There's more use of electricity, so the economy becomes more electrified, and more of electricity is generated by carbon-free sources. That's the only way it could be done mechanically. The 2D scenario is the one where you get to the level of emissions associated with a 2 degree centigrade warming. The 2DR scenario is one in which the deployment of nuclear power and carbon capture and sequestration is restrained by political and other non-economic forces. You can't see it here, but electricity grows over this period in their scenarios. And not only does do solar and wind increase in terms of their share of generation, but in absolute terms the scale-up is dramatic. Now, there may be ways to do this. Maybe compact nuclear reactors. Maybe something else. But this is a scenario that is not dissimilar to other studies that say there are limits to the deployment of hydro. There are limits to the deployment of nuclear power that may have to do with non-economic factors. And biomass is limited. What's left is wind and solar.

Now in this scenario, solar goes up by more than two orders of magnitude. So if you say, "We're serious about emissions reductions," then you have to be serious about renewables in the long run. So economists like to actually pretend we can get stuff done. The question is, if we could actually get stuff done, how would we propose to start down that road? Well, you'd clearly want to get these technologies to be even more efficient. There's a case for doing work on nuclear. You run into enthusiasts for compact nuclear reactors that are taken to locations on the back of trucks all the time. We don't know if that can be done at any reasonable cost or at all. We're finding out. But clearly you would like to get solar, which is currently way out of the money, closer to the money. You'd like to see what can reduce the cost of wind. But that's a standard spill over argument for doing publicly funded R&D, with a twist saying these are technologies that are potentially a vital importance. There's a spill over argument for doing R&D on anything. But these may be particularly important. Clearly, you should also price carbon. It's heartening to see how many people are actually standing up and saying this in public these days. Very few of them with R's tattooed on their heads, but that may change one day.

Now a threshold question is, if you have a price on carbon, do you also want to have deployment support for wind, solar or possibly nuclear? The answer is probably not. That's not to say that the kinds of complementary policies that Speaker 2 talked about that have to do with getting permitting right, getting information right, just all of the kind of down in the weeds stuff that can impede market functioning, that's not to say you wouldn't want to do all those things. One of the reasons why residential solar costs much more in the US than in Germany is because every town has different standards for residential PV. And you talk to installers, talk to anybody, and they complain that you can't develop standard procedures. So fixing that and a variety of other issues is important.

But if you've got a cap on emissions or if you got a tax on emissions, there is no emissions gain from subsidizing a particular technology. That's kind of important. If you do that, you raise the cost of meeting the constraint under a cap. Under a tax, you'll get additional emissions reductions because you're putting in an additional push on the system, but you raise the cost per ton. The only argument in that regime for an additional support is if you think there are going to be learning economies with spillovers for a technology that might be important in the future. Then pushing that market might get you technical progress that way. That's inevitable. Everybody assumes it's inevitable. It's not inevitable that that happens, but it's possible.

OK. I love that world, but we're not there, even in New England with RGGI, because the carbon price isn't that high. Suppose we are where we are. Well, there's still a good case for doing R&D. The spill over argument, the potential importance argument… I'm co-heading one of these "Future of" MIT studies and we're doing it on solar energy, and we will have rather sharp recommendations for changing the way the government does R&D in this area. Just because there's an argument for some doesn't mean it couldn't be better.

Could a well designed subsidy policy for renewables be part of an Nth best approach to control emissions? (We can debate what N is.) First of all, this is a very hypothetical question. If you read state renewable portfolio statues, particularly the most recent bunch of them, they do not mention climate. Michigan's leads off with energy security. You worry about an invasion from Wisconsin? I don't know what the problem is in Michigan. I seek to understand. But they're not about climate. They're about job creation, clean energy jobs, which probably doesn't affect net employment but affects the mix. So this is not what's going on. Now whether this is second best or third best depends on what's feasible and what's not feasible. So that's a little bit hard to judge. It is difficult for me to see, and we could have this argument whether subsidizing renewables gets you more bang for the buck, if that's what you're about, than pushing substitution of gas for coal, efficiency polices, and so forth.

Again, you could argue for subsidies from the point of view of thinking about 2050 to say, "We want industry R&D to be done." I don't think much advance in wind technology came from government I think that all happened in industry, if I'm not mistaken. And I expect there were spillovers, in fact, encouraged to some extent by NREL and others. So you could argue for a subsidy to advance the technology through the process of growth and learning. But it's a different case. It's a different case.

Now I can't resist saying that I talked there about a well-designed subsidy program. I want to say a little bit about what we have here. The investment tax credit, and I think to an important extent the production tax credit (but correct me if I'm wrong) typically requires going through the tax equity market to monetize that subsidy. And in all the estimates I've seen, the bankers rake off a sizable chunk of the subsidy. Now it is important to keep Wall Street healthy, obviously. But if you want to subsidize renewables, you don't necessarily want to subsidize Goldman Sachs to a large extent. And a lot of state and local policies also work through the tax system. You contrast the US policy regime with, say, the German regime. The website DSIRE (Database of State Incentives for Renewables & Efficiency) maintained by North Carolina State for DOE that goes through all the various state, local, and federal subsidies is really interesting reading, because there are hundreds of them. Most of them work through the tax code. San Francisco exempts PV systems from property taxes. OK. So do about a half dozen other California communities. What's the cost of that? We don't have a clue what we spend subsidizing renewab1es. It's quite fascinating. The German feed-in tariff is written in a couple of pages and the costs are visible. The costs in the US are hidden. So the tax equity market is a problem.

The use of the tax system, to my mind as sort of a good government type, has as its main feature hiding costs. The investment tax credit--which was the most visible subsidy for solar along with the accelerated depreciation which I think wind also benefits from as do a lot of other sectors--investment tax rhetoric rewards input, not output. If you care about displacing carbon, you care about generation, not about spending. And since it's a percentage, it subsidizes rooftop solar, residential solar, more per kilowatt hour than utility scale solar. Utility scale has substantially lower costs. Why you would want to do that is somewhat beyond me, but it's done.

Let me also just simply say that the model that's driving residential solar deployment these days is third party owned systems that go on your roof. You don't own them. The third party owns them. If you bought them, the investment amount would be clear. If the third party builds them, the investment amount is a transfer price. And there are lawsuits, and one recent paper says the average overstatement is 10%.

The production tax credit (like a blanket feed-in tariff, let's be fair) rewards production whenever it occurs even if prices are negative. One can do better. One can do better than this. And the instability in the production tax credit is really wretched policy no matter how you think about it. The ups and downs in wind capacity installation…to what question could that possibly be the answer?

Finally, I have to do a little riff on Renewable Portfolio Standards. They're all different. And they all seem to have the aims of promoting particular technologies. Rhode Island has either three or four different kinds of technologies that are separately required. And my favorite, of course, is North Carolina, which has particular quantitative requirements for electricity generated from swine waste and electricity generated from poultry waste. Now, that's not a carbon mitigation strategy. That's an economic development strategy. But it's not necessarily an efficient carbon mitigation strategy. They don't deal with timing--generate at night, generated in the day, generate whenever. Same recs produced. And trading.

So I'll come back to the other paper. One of the key findings in the other paper that looked at hourly data and hourly prices and hourly generation for a sample of wind and solar units is that the performance difference is the capacity factors differ enormously across the country. Renewable Portfolio Standards with only two exceptions constrain where you can get your renewable electricity. So with all due respect to Massachusetts, do we require residential solar to be in state? New Jersey does. I don't know whether we do or not. I think it may be required in Massachusetts. An efficient greenhouse gas policy would say that if Massachusetts wants to subsidize solar to reduce carbon, it should subsidize construction of solar in Arizona. But we don't want to do that, because we want the jobs in Massachusetts. But that means that per dollar of spending, we're getting less emissions reduction. So, as an emissions reduction strategy, 30 different Renewable Portfolio Standards, all different, all but two with siting restrictions, is a very inefficient carbon reduction strategy. So with that, I will close. Thank you.

Question: I just had a quick question. You were commenting that one of the major difficulties with rooftop solar is county and city government. Is that the major disincentive for not putting rooftop solar on?

Speaker 4: Well, you want to wait for our study which I hope comes out in January. We've looked at that closely. The interesting question and the way to frame it is how come it's so much more expensive in the US than it is in Germany? Because modules and inverters are pretty much commodities globally, and it's a lot more expensive here. Some of it is that the market's less mature. Some of it is that installers have lower scale. Some of the lower scales is driven by the fragmentation. Some of it is less information on the part of consumers. So customer acquisition costs are higher. There are a whole bunch of reasons. But the fragmentation and the separate requirements in most municipalities certainly adds to it. And in some areas, I will say, I know in Connecticut. I don't know if it's happening here, but in Connecticut, groups of municipalities are getting together to try to harmonize standards because people see this. It's pretty visible.

Question: You mentioned a couple of times during the presentation the difference between economic development and carbon mitigation. I guess I would like to tee up the question maybe for after the break as to who decides at the end of the day whether we should be on a course with our overall national energy policies to incentivize the development of the economy or should we be incentivizing the reduction of carbon?

Speaker 4: I think that's a very, very big question. And it has never been answered to my satisfaction. I think this is a good one for after the break. Let me just say I think the answer is yes. I think and this is particularly true if you think about beyond the US. A carbon reduction strategy that really hinders economic growth is not politically stable. It's not viable. So if you're going to say to the Chinese, "Slow down your growth, because it's getting warm over here," or say that to the Indians, that's not going to happen, which is why I put a lot of emphasis on R&D to get the costs down. I mean, solar is out of the money and to say to the Indians and the Chinese (I know the Chinese are putting a lot of solar up) that they should go increase that by two orders of magnitude and stop burning their cheap coal and, oh, by the way, let those people in the rural areas suffer--I don't think so. So I think to turn that around, the answer to your question has to be yes.

General Discussion

Moderator: To return to the question from before the break, who decides nationally if we're going to have an economic development policy or a carbon reduction policy, and are the two mutually exclusive? Anybody from the panel want to respond to that?

Speaker 2: As I hope I have made clear, I actually think that's the wrong question. We shouldn't be asking, is it carbon solutions or economic development? I think it's exactly what Speaker 4 said at the end. That is, and I'm going to quote you, "a greenhouse gas policy that hinders economic growth is not viable." I think that's exactly true, and that's part of the whole idea of linking environmental policy, economic policy, and energy policy, because the solutions to this are going to have to overlap. They're going to have to make that question about economy or carbon policy a moot question. And I think there are many different places that have shown that that can happen. Massachusetts is just one of those. But I think that's exactly the sweet spot of the kind of policies that we've been doing here and in New England and in other places.

Speaker 4: I would say one thing, though, in response to the quotation of me. I'm not sure you can make it free. I think it's a question of making it affordable.

Speaker 2: I'm not going to disagree. And again, as I said, with respect to our suite of polices, some of them are not free. Our solar policy is not free. But we've chosen as a state to make a decision that we're going to advance solar. We will pay a lot for greenhouse gas reductions but get other benefits in the meantime. And I know that our state is very different than other states. So what I'm not saying this is true for other states, particularly coal states. But in Massachusetts and New England in general we send 80% of our energy dollars out of the state to wherever we're getting our resources. And so, of course, a big piece of what we want to do, and we have no shame about it, is to keep energy dollars in Massachusetts, because we know that that they will have primary and secondary and tertiary economic impacts. I'd much rather pay an installer to put up expensive solar than spend those dollars from gas that's coming in an LNG tanker from Yemen.

Questioner: Let me put a footnote on the question. Speaker 4, you are adding the word "affordable," which I think is very important. But I guess what I was really getting to is the idea that you'll have a referendum in Massachusetts or in Illinois or Montana about whether we should allow gaming, or whether we should devote $150 million to the highway system, and yet this is a much more expensive proposition. And I'm not suggesting that we just do what China had done in the past and maybe to some degree is still doing, which is just to build the cheapest generation you possibly can, to use local coal and not care about the air or anything like that. But on a sort of representative basis of voters or congressional leaders or governors or so on, who decides? Or who has decided, or has anybody decided?

Speaker 2: When Governor Patrick ran for office, one of the fundamental parts of his platform had to do with building a clean energy economy and linking environmental protection and economic development. The voters said yes. Cape Wind was a big part of the debate in his second election. And he was elected--the voters said yes. Who knows what's going to happen in the next administration? I don't know. But part of our strategy has been that regular people see what some of the benefits are and see what the costs are, too. So there's no question that in our state, we have Fortune 500 companies. We have mom and pop shops who are looking at their electric bills (not necessarily at the rates), and they are going down, and their neighbors are saying, "We want some of that action."

Moderator: It is a challenge, though, because the question was about who nationally decides.

And the reality is that maybe it isn't a national decision. In Arizona economic development is part of the equation as well, and may depend on whether you have elected commissioners versus appointed commissioners. That has a difference in the balance. So the challenge is that it's going to be different in Montana and Arizona and Michigan and Massachusetts. So the national concept may be something that can't be accomplished. So it's a big question in the room.

Speaker 1: First of all, I agree that pricing carbon can be complementary to some renewable incentives. For example, if you have a renewable incentive and no pricing of carbon, it's more likely you're going to displace natural gas, which is a low emission fuel. Whereas if you have a price on carbon, renewables are more likely to displace coal. So that's clearly one issue, and I think it can make a big difference. Secondly, you said here, Speaker 3, that I made an assumption of 20.5% on the wind plant capacity factor. Actually I corrected that, because despite the fact that Amory Lovins did not use what I regard as gentlemanly language in his attack on me, he did make some good points and I did recognize them and I incorporated them into the analysis. One was the more recent capacity factor numbers. It's much more appropriate. And I think he made some interesting points on nuclear which I think were well taken, particularly the fact that not only does nuclear have a high operating and maintenance cost, it has a high required capital investment cost, over time, because of the constant need to upgrade and meet new regulations and so on. When you add that all in, nuclear doesn't look quite as good as it did in my original or first paper. I'm glad you pointed out, Speaker 3, that 2013 was a totally unrepresentative year for wind. Going from 13 gigawatts of installed capacity in 2012 and declining by 92% to one gigawatt means that there must have been a lot of turbine manufacturers out there quite willing to do some deals. So I don't think it was appropriate to use the 2013 numbers.

Everything I did in megawatts also can be done in megawatt hours. In fact, in the last part of the paper, I give the assumptions about capacity factors, so you just multiply them by the number of hours, and so on. And you can just restate everything in gigawatt hours, which is more important and maybe would have been a better way to have done the analysis.

And a comment on Speaker 4's paper. It's startling to see that in order to make happen the two degree centigrade increase by 2050, it depends on which scenario, but you need anywhere between 17 and 27% solar, anywhere between 18% and 21% wind and 18 or 19% hydro. But I really wonder ,why would anyone want to invest in a nuclear plant when you have so much renewable energy coming on at zero marginal cost? You won't be running your nuclear plants at night. So I think it would be hard to find someone willing to invest in a nuclear plant in that kind of scenario.

I didn't put a lot of emphasis on integration costs, but the more I read about it, the more I see it, the more I am concerned about how we can effectively integrate wind and solar at much great penetrations into the electricity system. There's a paper by Gordon Hughes, who's got his own bias, but basically he said that what's likely to happen is that nobody's going to invest in nuclear. Nobody's going to invest in coal baseload plants. Nobody's going to invest in combined cycle plants. You're going to have a situation in which you have wind, solar, and other renewables, hydro, and inefficient single cycle natural gas. And that's what it's going to look like. And somebody ought to do the numbers and really work that through because I think that's a big concern.

Question 2: Well, first of all, let me just admit freely that I'm an elected Republican. And like most Republicans, I suffer from this belief that men and women are fallen creatures. And as a result, we don't keep our word. I recall that we had a candidate for governor years ago who ran on the platform of, "Let's approve a lottery and we'll take all the money from that and we'll use it for education." Well, the lottery passed, but the money is not used for education. So this leads me to my question. With a carbon tax, how do I know that the money will be used for its intended purpose and it's not just a tax?

Speaker 4: Most of the carbon tax proposals earmark as part of the legislation. I would favor using the revenue to reduce other taxes. That seems to be too complicated. So the proposals that seem to be getting more traction involve rebates. They'll be revenue neutral. So we'll rebate it per capita or some way like that.

It's more economically efficient to use that tax to reduce other taxes, so you reduce the distortion on the margin. That may be too complicated. But I think it's got to be in the legislation. If you looked at Waxman-Markey, they were going to auction some of the allowances for carbon. And then it was just a spending spree in that bill. And it was like, "Well, these are all good things but that's not what I would spend it on." So I think it has to be in the bill.

Speaker 1: I agree that to reduce other taxes is the right way to go about it, but again, politically this may be difficult. I think British Columbia has an example of a carbon tax which is rebatable, and it is very, very popular. It's a little bit of a strange thing, because it's really a tax on gasoline and kerosene and hydrocarbon fuels, very similar to an excise tax, and administered as an excise tax, but it is rebated, and that's made it very popular.

Speaker 3: With respect to Speaker 1's response, first of all, I appreciate the changes that were made and recognize that it's an evolving paper and it wasn't your fault. I don't blame you that the *Economist* picked it up and spread the results around the world and drew policy conclusions that every country is now reading about and using against us in various policy debates. [LAUGHTER]

So you're innocent, but I think the paper still has the same assumptions on the gas capacity factor, wind capital costs…the ones I said before.

A focus on integration cost sounds like where you're going. Again, that can be measured. Each system operator measures that. They have a cost of their reserves. You can ask. PJM has got a study out. ERCOT's got a study. They're looking at actual evidence, and then we run the model of the power system. So let's actually measure it. If you do that for even what people consider high levels of penetration, 20% and more, you're not talking about more than a couple bucks a megawatt hour. It's right around the range for conventional generators. So let's look at the facts and look at the actual system operator evidence on that, too, and I think the conclusions will get back to finding the renewables faring a lot better using your methodology.

And just one point generally on Speaker 4's comments. I agree with most of the things in the paper. So, without intending to give the impression that I'm criticizing much of it, just let me say on the negative pricing that is not only a Texas thing. The same dynamic happened in MISO and the other places where you find and the slide showed it. The negative pricing went up for a couple of years and it's down. It's almost gone in those places. The issue is that you can get a timing mismatch between transmission and generation development. I don't think we've seen the last of that. That may happen again in some places when you develop wind in good resource areas and you build transmission and they may not be energized at exactly the same time. But it's very solvable, and the transmission is usually very economic. So I don't think that will be a long-term issue that will be of concern.

Speaker 1: Speaker 3 raised a new point that I'd like to respond to. In my paper, I used $2.50 for cycling costs and, as I said, I was criticized heavily by a lot of people for having done that. I can just cite the nuclear energy association of the OECD, which says that looking across several different countries, the integration costs are $16 to $21.00 for wind at 10% penetration and $15 to $58.00 for solar at penetration of 10%. I have seen so many estimates of cycling costs. I have no way of telling which is accurate. They're all over the place. It's obviously an area that needs a lot more study.

Speaker 3: That was from the nuclear association.

Speaker 1: And you're from the wind association. But I think one is clear and that is it depends on what the rest of system looks like. If you've got a lot of hydro, don't you have a lot of hydro. It depends on the level of penetration. It's not linear. So there's no one number.

Speaker 3: And for some technologies, as you said, it declines over time. I don't think that's very true for wind. But the more you add for some resources and some systems…the capacity value and the reliability issues can get worse but actually wind being spread out at various times of day actually helps.

Question 3: So I would like to ask a question of the proponents of second best policies that I hear. I understand the principle, and I even agree that if you can't get the first best, then you take the second best, and all that kind of thing. But it's often helpful to think clearly about what the first best is so you can see what actually happens and then see whether or not the second best is actually solving the problem that you're trying to solve.

So let me pose a stylized version of my first best policy, which is going to be not a big surprise. I think carbon is a serious problem. I think it's a global problem. I think it's going to be expensive dealing with it. I think it's worth it. So I think we should do it. So I don't think it's free and I think there is a tradeoff between conventional economic growth and dealing with this problem. We just have to face that, but I think it's definitely worth it. I would adopt a significant carbon tax. Take the one that's estimated by the US government in the $30 to $40.00 range per ton of carbon dioxide. One of the complaints about that carbon tax is it's not going to have the kind of impact that people want to have, because you won't get all these technologies adopted, because they're too expensive. So that's why people want to have mandated standards, because they want to get more than what the carbon tax would say. But the first policy would be to have the carbon tax.

When you do that calculation with the carbon tax, my numbers tell me that in terms of the learning by doing premium, the direct subsidy that we would apply to things like renewables is pretty small. In percentage terms, it's in single digits. So you don't use the learning by doing to get a lot of deployment. If you have a lot of deployment, there's a small learning by doing premium that you can take advantage of. So you don't want to get the argument backwards. And that's really important when you look at the United States and especially when you look at the rest of the world (and if you want to deal with carbon, you've got to deal with the rest of the world, too), because this stuff is just too expensive.

So what we should be doing is spending a lot more money upstream on the R&D development, and the things that I think Speaker 4 was talking about. That's the really critical problem. And we're spending billions of dollars in states implementing programs to deploy technologies which are too expensive and ARPA-E's budget in the Department of Energy is an order of magnitude too low--$300 million a year right now, which seems to me completely upside down. So we should not be spending the money to deploy the technologies that are probably too expensive and there's not much learning by doing benefit from that. What we should be doing is spending a lot more money on R&D in order to get the technology cost down so that we can meet the Google mantra of "Renewable energy less than the cost of coal," which is what I would think would be a terrific outcome if we could get there.

I haven't heard anything on these second best policies that gets us close to that first best policy. As a matter of fact, I didn't hear anything in the second best policies that even mentioned ARPA-E. I only heard it in the first best policy, but in the second best policy we're ignoring this R&D story, and just coming from the point of view that we've got to get that stuff out there and deploy it, because that will drive the cost down. Yeah, it will drive the cost down from way too expensive to too expensive. And so it doesn't solve our problem. What is the second best strategy that gets more money to ARPA-E?

Speaker 2: Let me just try to clarify your question because I'm hearing two pieces of it. The first best policy you mean is a carbon tax. And then also federal spending on R&D.

I have a couple of answers. One, I'm not quite sure why what we've been doing in Massachusetts doesn't approximate that, given that we're not the federal government, etc. We've priced carbon through RGGI, understanding it was a low price. We have invested a lot in R&D and tapped into ARPA-E as much as we possibly can. So given that we're a small state, it seems like that has been a path that we've taken. Now, we haven't had the kind of timeframe of the results of the R&D investments showing up in a lot of ways, but there have been some results. Through some of our R&D investments, there have been cost reductions and increases in the simplicity of solar installations because some new very simple technologies have been developed by companies here that make the installation of solar a whole lot easier and cheaper. So, again, I'm not saying that this is a whole answer but it sure seems like it gets pretty close to it.

But here's my other piece on the first-best, and it just goes to a kind of simple question. What would you give the probability of a federal carbon tax moving forward in the near term and after November when the Senate might flip? What's the probability that you give for that?

Questioner: I think the probability is low and I think I actually disagree with some of the comments earlier. I think it's much more likely to be driven by tax policy, where it's going to substitute for other taxes, but it's not going to be reducing other taxes. It's going to be not raising them, because we're going to have to raise taxes in order to deal with the deficit problem. And I think it will be part of that package. And it won't be done because of carbon. It will be done because of the money. So I don't think it's zero, but I'm not fully confident that it's going to happen soon. I think it might happen eventually, because of the money.

Speaker 2: So I guess having come from a state where I work for a governor who always describes himself as very impatient to get things done, we don't want to wait for the first best. It's just not going to happen any time soon. And so we're looking at the second best and maybe even the third best, and we're trying to connect them with a variety of things to mitigate some of the economic impacts, whether it's through caps on net metering or whatever it is, we pull together our bag of tools to try to reach this combined goal of greenhouse gas emissions, energy cost security, mitigation of volatility of prices, clean jobs, keeping energy dollars here... Of course it's going to be a mishmash. That's how it is, especially when there isn't a driver on the federal level. And I'm proud of that second, third, fourth best that we've put together. I think it's solved a lot of problems and brought benefits to people here in a significant way.

Speaker 3: I agree with most of what the questioner said. If you're arguing, however, that our government R&D is better and deployment incentives are behind that, I would disagree with that. As Speaker 4 said, most of the technological improvements are in the private sector. They've been driven by profit motives. They've been driven by deployment incentives, particularly production-based deployment incentives. In the case of wind, these machines work because you get paid when you produce, not just for the investment, as with the early California incentives that were set up in the 1990 timeframe. So I think there are ways to design incentives effectively so that they are efficient and achieve the performance goals so that they can be more effective. I don't disagree with the ARPA-E budget claim, but at least in the wind space we don't need any kind of revolutionary technological breakthroughs. We do need to steadily bring our costs down with manufacturing operations and just steady improvements on the technology.

Speaker 4: I think wind and solar are different in that regard. I think the current solar technology, single and multi-crystal and silicon, are getting close enough to their efficiency limits and the manufacturing is automated enough that to get solar cheaper, we have to go down a different path. And that really requires developing some new technologies. So I think for solar, government R&D can be very important. Less so for wind, as far as I know.

Speaker 2: And then throw in storage. And then this is a completely different conversation. And, absolutely, the federal government should be spending way more than it is at this point on storage.

Speaker 4: Storage, and the other thing we've had a little bit of a look at is that you can store electricity or you can think about converting sunlight to fuel without going to electricity. There's some work on that. You can also improve thermal storage in solar thermal plants. So there are a whole lot of ways to push on storage which helps with all these integration issues and is probably past 2050 but is really important to work on.

Question 4: I'm struck by something that you said, Speaker 4, in your presentation about the RPSes and that you've got 29 different RPSes. They're all very different. They all are trying to keep a lot of the renewables within state. Speaker 2, you made a comment saying, "Of course I want them in state even though it's more efficient for me to pay for solar in Arizona, because I want the jobs here and everything else." So I'm struck by the cognitive dissonance here. With RPSes that are state driven and yet, Speaker 2, you're part of a program called RGGI, which is a regional compliance program. Massachusetts is part of a regional transmission organization and ISO New England which does regional dispatching and takes advantage of those economies of scope and scale. And there are Section 111(d) proposals that EPA has put out as trying to encourage regional cooperation here. So why is it we're trying to undo everything we've learned with cap and trade programs in the past by trying to keep this protectionist stuff at home? That's the first question.

The second question is with respect to RPS and carbon policy, and I am thinking about the Waxman-Markey bill. Isn't an RPS a way of just hiding the true cost, going back to the earlier questioner's point? This is actually an expensive endeavor. Isn't an RPS just a way to hide the true cost? And the reason I say that is because, in the PJM footprint, we have a lot of states that are saying, "Deploy renewables. It will suppress wholesale prices. That's the headline price." By the way, what they're not telling you is that it's going to show up as another line item on your bill, hidden away. So what is the true cost here of that policy?

And then, finally, I want to leave you with this, Speaker 2, especially since you are talking about this protectionist issue. I would rather have the jobs here in Massachusetts. Is anybody here from Iowa? OK. I'll use an example I used to use with my students at Minnesota talking about gains from trade. To say that I want to keep things at home would be like telling people in Iowa, "Don't spend your vacation money in Florida to go to Disney and enjoy the sunshine when it's well below zero and one degree above death. Stay here in Iowa and suffer. Spend your money here, and, oh, by the way, Florida the same thing. We don't want you to buy your corn and soybeans and pork from Iowa. Why don't we just have it all right down here?" And we're losing so much from the potential gains of trade. So when you start thinking about it in those terms, why are we going down this road?

Moderator: The quick answer is that all politics is local. I mean that's the first answer. But there is a better answer that I'm sure Speaker 2 has.

Speaker 2: Oh, no, I don't know if it's better, but it's related, and it goes back to the earlier point about first best. First best in my mind is often in a world of no tradeoffs. And when you're in state government, you don't optimize on one thing. You optimize on many, many things. So it's a false dichotomy that you're setting up, and you're using a kind of hyperbole to expose something that's not the reality. I wouldn't tell Massachusetts people not to go to Florida. Obviously that makes sense. But if we can get a policy that can reduce greenhouse gases efficiently by being members of a Regional Greenhouse Gas Initiative, and we can also try to keep some of those benefits in state and thread the needle to balance that and to balance those tradeoffs, that's what we're going to want to do. That's what everyone does. You have to have to tradeoffs, and that's why first best is not always the best way to think about it.

Speaker 4: I would also say, with respect to the RPSes, when I said they restrict trading, they don't all require everything to be in state. In fact, Massachusetts can buy RECs regionally, and New York…

Speaker 2: We've tried to harmonize the RPS program across the New England states. Not perfectly, but we do.

Comment: You can't buy in Arizona because can you imagine saying to the voters, here's a plan. We're going to pay people in Arizona to generate electricity with solar power. You couldn't possibly sell that. You just stay quiet. You just say quietly and, of course, it will be regional as all of our programs are. That you can sell.

Speaker 2: But if we do get to regional programs through 111(d)…I've had commissioners from other states not contiguous with New England who have said, "Well, what would it be like to join RGGI thousands of miles away? I'm hopeful that there's a way that we can convince people in the commonwealth that it's worth it to be part of a trading program with some far off state that can reduce emissions more cheaply. But we also want to have programs that keep some benefits in state.

Comment: Hence, California just agreed to merge with Quebec.

Speaker 2: With Quebec. Right.

Comment: We already are merged with Quebec. Yes.

Speaker 2: So it's not realistic. What we're trying to do is balance the kind of perfect program with the realities on the ground.

Questioner: Why are we letting politics trump people leaving money on the table? I would argue that Massachusetts is leaving money on the table by not allowing Arizona to do solar when it's more efficient.

Speaker 2: We'd be happy to do that. We've been arguing with EPA to let us have those kinds of relationships. We are not leaving money on the table. I think there are many, many other states, I can think of several, that are leaving money on the table because they are saying we shouldn't be going down this road at all and there are huge benefits that can be gotten from energy efficiency in particular. And essentially states that are not moving forward are saying to customers, "We're going to require you to spend more on the services that energy provide," because of whatever reasons, political or otherwise.

Speaker 4: Also, you said, "Why are letting politics make policy?" How else do you make policy?

Question 5: I think Speaker 4 answered my question on solar. I got the impression from a presentation at MIT a year ago that if we use the learning by doing paradigm, we would go asymptotically from very expensive to expensive. And my question to Speaker 4 is, could you comment on the Pindyck study or paper on carbon models? And just as a comment, Posner in a decision in a MISO case recently declared the Michigan in-state sourcing requirement to be unconstitutional, which means that at least in the seventh circuit it's unconstitutional, I believe, if I get my law right.

Speaker 4: I think that's good. I think that could be interesting. That may well go up to the Supremes, and yeah, you can't normally require stuff be done in-state. It does sound like an interference with interstate commerce but almost all, all but two of the RPSs have requirements like that that limit siting.

On the Pindyck study, people probably don't know this paper, by Bob Pindyck in the Journal of Economic Perspectives, Bob, my good friend and colleague, Bob Pindyck, hammered the integrated assessment climate models from which the government's carbon tax, carbon charge number is derived. And he had a number of criticisms, but fundamentally those models have damage functions. When the temperature warms by so much, or CO2 rises by so much, damages to the world economy are X. And what Bob Pindyck says correctly is that the foundations for those functions are weak at best. I will say MIT has a very complicated model of the global economy and the climate system that does not have a damage function in it because the folks involved recognized we didn't know enough to write one down. So what Bob is saying is that that particular emperor has no clothes, and I completely agree with him. I completely agree. We don't know.

There was a piece in the *Times* by Steve Koonin. I don't know if anybody saw it. It said that climate science is not settled, which from a distinguished scientist is at first blush a little disturbing. He says that of course the earth is warming, and of course humans are doing it. But there's a lot of uncertainty about the climate system, and we don't know enough to defend particular policies. That's right, too. That just means we don't know whether $40.00 is the right number. But if you take the carbon problem seriously, there is a number. There are problems. And Pindyck has been unfortunately adopted by the climate deniers as saying, "Well, see, we don't know so we shouldn't do anything." And, boy, does he not think that. I don't remember what he proposed. I would think he'd go higher than that, personally. But in any case, Bob has written a number of other papers about how you respond to the possibility of a catastrophic event when you don't know the probability and how you think about that. And that's what he has in mind here. We don't know the damage function, but there's a lot of scary possibilities and we have only one planet, is his position the last time I looked.

Question 6: So most of the discussion to this point seems to have talked about how market-based policy, climate tax or cap and trade, and complementary policies, Renewable Portfolio

Standards and the like, somehow potentially work well together. And I guess I want to suggest that there are a couple ways in which they don't. And part of it goes to a point that Speaker 4 made, which was that if we have a market-based policy, and we layer on a Renewable Portfolio Standard or such, chances are we're not going to reduce any more emissions, but the costs are going to be higher. And this is something that I've done a lot of work on in California; they are starting to realize in California now, where basically the market price for carbon is at the price floor of about $12.00 or $13.00, whereas there are a number of other policies, Renewable Portfolio Standards, low carbon fuel standards, which are all achieving reductions at a much higher cost.

And that brings me to sort of the second effect which is potentially a nefarious one which these complementary policies potentially have--the effect of dampening that carbon price signal in a system in which they are both operating. And in effect, that's what's happened in California now, where the price is down around $13.00, and really in terms of carbon mitigation is not incentivizing a lot of emission reductions. What it's also not doing is keeping existing low carbon generation sources such as nuclear in the markets. And this is kind of the RPS bias, and a number of jurisdictions are finding this is an issue as we see an increasing number of nuclear plants either outright retiring, such as Vermont Yankee here in New England, or as we see in the Midwest a number of nuclear plants that have not cleared in the most recent capacity auction.

And at this point, California is beginning to have this discussion. It's starting to think beyond 2020 and they're thinking about what goes beyond. And whenever I talk with people about, "Well, isn't this is a good time to drop the RPS and low carbon fuel standards and just go to a carbon cap and trade?" the concern really gets to the political question. And that gets to how comfortable will people be when that carbon price spikes to $40, $50.00? The price cap is about $50 but chances are at $50, you'd hit that ceiling pretty quickly. And politically the question is, are we ready for that, and is that just going to unravel the whole thing? And so I guess to tie it back to this morning's question, which was largely about are we politically ready to face the high prices it's going to take to get the performance we want? This seems to me tied to the same issue--we need to get carbon pricing systems in place, get people used to the idea, and then that's kind of step one to acclimating our society to some kind of market-based carbon solution, which it seems to me in the end there's some agreement that that's where we need to head. And so I just wanted to get people's reactions to how they see that these things working together and evolving.

Speaker 1: Well, as I said, I think the two can be complementary. Basically, if you're at the floor price, then you ought to think about lowering your emission targets. I mean, you don't want to be at the floor and you don't want to be at the ceiling. You want to be somewhere in between. And an RPS can help you reduce emissions, but it does undermine a particular price and/or quantity being required by the state. So why not lower the quantity? Why not be tougher?

Speaker 4: I think the problem you mention is a real one, and the European experience highlights it. Europe has, as I expect you all know, a carbon trading system, the European ETS, which allows Europe-wide trading. They also have renewables requirements. Those don't allow trading between countries. If you look at them, a good predictor of the severity of the requirement is per capita income. So it's not clear where they come from, but it was explained to me at one point that the reason carbon could be traded and renewables couldn't is Germany wanted to build a renewables industry, thank you very much, and so they wanted to require themselves to generate. The result of all that and the recession is that the European carbon price is low. The European Renewable Standard is binding. And so you're building wind and solar and coal plants because all the renewables are holding emissions down. So why not build coal plants? So a low carbon price probably means you're not reducing emissions in the most efficient fashion. You're not putting pressure on HVAC systems. You're not putting pressure on building efficiency broadly, because fuel prices are relatively low. You're not putting pressure on motor vehicles, because gasoline prices are not being affected by high carbon charge. So, yeah, you're meeting the target, but the notion that the way to meet the target is windmills and coal plants is probably not right.

Speaker 1: In fact, in Germany, the emissions are going up, not down, because of the reduction in nuclear and substitution of coal for gas, because gas is very, very expensive in Europe, more than $10.00 a million BTUs. Therefore, I go back to the idea that having a cap and trade system without some target price makes no sense. I mean, you've got to structure it so that you reach some target price or some target price range. Otherwise, it's very ineffective.

Question *7*: This has been very interesting. I, like the earlier questioner, am an elected Republican, though I won't be going back to the Garden of Eden in my comments. But as a policymaker, I guess what I've always tried to have sort of top of mind is the question, what is the primary motivation for the thing that I want to do? And the thing we want to do is reduce greenhouse gas emissions and thus mitigate the effects of human-caused global warming. And I understand Speaker 2's point that that then needs to be translated into political reality. So you go from a policy that might be the most economically efficient, something like the one in the article in our handout that talks about an economy-wide carbon tax with a capital tax offset. And then you begin sort of modifying or adding to or totally eviscerating it, for that matter, by saying, "Well, we need to get union support, so this needs to be in-state. We need to get the farmers' support, so you better get in the swine waste. We need the wind energy support, so there had better be a volumetric tax credit for wind production," etc. And I guess it hearkens back almost to something one of my old bosses, Bill Buckley, used to say, that as a conservative, he wanted to see nominated in Republican primaries the most conservative person who could actually win a general election.

And I wonder if the panelists would agree with at least the principle that the policy you want to see on the table here is the most economically efficient carbon reduction policy that actually can pass through our political system. And to me, there's a spectrum of options ranging from that carbon tax all the way down to the swine farm. And I guess my only concern is that whatever you arrive at that's politically palatable is also going to be something that really may not solve for the harms you've identified in the end. And I guess that's my real concern. So I'd ask whether the panelists agree with the principle in general. Because people are bananas for renewables. They love them. They want to keep the production tax credit generally. They want to see these things built--something I question the validity of, but whatever. So I'd be interesting in maybe in Speaker 4's response and anyone else who cares to answer. Let's just assume federal tax policy is still used as a moving force for this kind of construction of renewable energy. What could be modified in that volumetric tax credit, that does result in a perverse system? What can be done with that type of policy to make it more economically sensible?

Speaker 4: As to what can be done with the production tax credit, I would make the credit increasing and really give incentives to site where you're like to get more on-peak generation. And there are, as I said, huge variations in the extent to which wind does that, depending on the site. But there's not particular incentive to look for those sites now. So that's how I would modify the production type credit, if you're going to do it.

I agree with the principle that you want the most efficient policy that addresses the problem that you can get passed, but with two caveats--you have to very careful to be sure it actually addresses the problem effectively. And I'm thinking now of Waxman-Markey, because a lot of people looked at Waxman-Markey and said, "Look at those agricultural credits. That provision is so elastic that there really is no actual guarantee that anything is going to happen." And the second caveat is related to that. And that is that you want to be careful of a policy that creates a vested interest that makes it impossible for you to go farther. So if you pass that, there'd be a farm interest in those wonderful credits for whatever you did, and you wouldn't be able to unravel that. It'd be like trying to repeal corn ethanol.

Speaker 3: I love the principle. Thank you for saying much more articulately what I was trying to say. Let's go for the most efficient second best. And I think that principle works out. I would keep in mind a few people have talked about the long list of renewable incentives out there on that North Carolina state website. There certainly are a lot, and in Europe there are feed-in tariffs and other things, and I'm certainly not advocating for layering on everything and doing all of the above. Let's look at the most efficient things. Let's collapse them into what is the most efficient and meet your criteria here. I think we should, however, also not ignore that every power source has some form of federal incentives. Those factor in the market as well. So let's not only look at renewable incentives, but look at everything.

Question 8: I have some of the same concerns that have been expressed. And we're fans of renewable energy. We've invested about $3½ billion in it so far and continue to invest more. And I understand we're in a kind of a second or nth-best policy, but as we conflate the policy objectives, I wonder, has anyone ever looked at what we're losing by combining, versus having separate policies to address whether it's a jobs program or an economic development program or a carbon program? It seems that there's sub-optimization that may be occurring as we do this. The other point I'd like to just ask picks up on the earlier question about the benefits of trade. We're hearing a lot in terms of the rhetoric at the local level that this has to be local, and anything that happens out of state is a wealth transfer. As we talk to people casually about 111(d), just feeling out how people feel about markets linking and things like that…I've talked to a regulator from a northeastern state that's in RGGI who is not that crazy about the idea of linking up with a coal state. Well, that sort of rhetoric has penetrated perhaps more broadly than what we thought. And I'm wondering if we've walked ourselves into an alley. Is there a point in the future where we can pivot? And how do you think that might evolve, given the layering of policies, whether we're talking about a production tax credit or whatever? Is anybody able to say that if the carbon price ever gets to this point, we wouldn't need this any longer? When do these things become flexible, or are they more like ethanol subsidies?

Speaker 2: It's a really interesting suite of questions. And with respect to your first question about whether we have thought about this issue of conflating different goals, and whether we are able to look at the impact of the policies on each of the different goals, we haven't done that on a quantitative basis. But certainly as we created that series of 15 different kinds of policies, we did think about where the balance point was between them. For example, we don't want just a solar installation job support bill. That wasn't our only goal. So we designed all of the programs in such a way that we would balance the interest we had in doing that and the interest in getting cheaper low-greenhouse-gas electricity. And we do think that by coal states joining something like RGGI ("we" being Massachusetts--I'm not going to speak for the other RGGI states. There's a lot of debate going on)…But we're convinced that the larger the market is, the better off we're all going to be, and the lower the prices will. We do see that a trading program offers the most cost effective way, compared to the other kind of conversations that are going around in the 111(d) area. So we're happy to entertain that. At the same time, we think about the question of how we could integrate those with some of the other goals that we have as a state.

Comment: You asked whether we are ever going to get to a point where we might de-layer all these policies. And I think that's really hard. I think once you put policies in place, you tend to create interest and support their continuation. So that worries me. I don't see a magic stroke that will de-layer this stuff--because federal preemption is out of fashion these days.

Question 9: First, a quick comment on R&D. To quote EPRI, there is less money spent on R&D in the electricity sector than there is on R&D on dog food, which is kind of a sad statement.

But my question is in a completely different area. Recognizing that a lot of what we're talking about here is looking out towards 2030 on the way to 2050 targets to achieve broad carbon reductions that we believe are necessary or critical, a lot of the focus, of course, of this discussion is on the electricity sector, which is a prime sector for contributing to carbon. But another significant sector and, in fact, in California the largest sector, is transportation. As we try to deal broadly, then, with the carbon issue, transportation electrification may be a critical component of what we need to do. So one of the challenges I think we face in looking at the electricity sector is how do we align our interests, rather than having them in opposition with the transportation sector, if we're going to be responsible for carbon emissions under a variety of the types of programs we've been talking about today, when we may be taking on a lot of the load to satisfy transportation fuel?

Speaker 4: On transportation, the economist's answer is, "Well, a carbon price raises the price of gasoline so that it incentivizes people to buy smaller cars and change where they live and all this stuff." Those responses appear to be weak. Hence you get mileage standards. And you justify the mileage standards by saying they are saving gasoline that people would have wanted to buy but shouldn't, basically. I think the beauty of a price regime is it does push on multiple margins, and if you begin to fantasize, you say, "Well, in the long run, expensive gasoline affects location choices. Denser cities make mass transit more economical," etc., etc. But that's a long run.

Speaker 2: You've just raised the excellent point of what happens when we start thinking about electrifying transportation. OK. Now, we all have to start thinking about this. But in New England, as you all know, the combination, particularly in the winter, of thermal and electricity is a huge policy challenge right now. And so we have to again start thinking about this in a more integrated kind of way. And this is why it's very important to have PUCs and FERC at the same table as EPA, federal DOT, state DOTs, and state environmental agencies, because otherwise we're not going to be able to solve those kinds of conundrums.

Speaker 1: It was mentioned during the break that there are some real externalities here between what you do on transportation and what you do in electricity in particular. The more electric cars you have, the lower is the cost of integration of renewables, particularly wind, which can be used at night to fuel the cars. So there is a true externality here between the two policies, and so I do agree they need to be integrated.

Comment: To work that trick, of course, you have to get prices right at retail.

Comment: Which is why grid modernization and real time pricing, etc., is such an important piece.

Question 10: Speaker 4 was talking about looking at the intent language of all the RPSes. Well, if you look at Washington State's, we don't have the word "carbon" anywhere in our intent language. But that was our intent. And the reason it's not in the intent language is because there was a certain political party that didn't want to acknowledge global warming. But they were willing to vote for the bill to make tradeoffs for whatever purposes. So you need to keep that in mind.

The second thing is, I believe that all of these steps we're taking are incremental by nature. People want to get their foot in the door. So we'll pass something that's not perfect, because we can get it this session. And it builds up, and I think it's interesting now that we're talking about how we've got all these policies in place and maybe we're going to replace them all with something comprehensive. I think politics is iterative. Things are going to change. And so even with 111(d) where we're saying, "Oh, the states don't want to work with others," I think what you're going to see is that right now they're all working to figure out how they're going to meet the 111(d) standards themselves because they don't want to go to negotiate with another state except from a position of strength. But they are eventually going to say, "There's mutual benefit. Let's talk." So that's my prediction. I think you're going to see a lot more working together in the year to come.

Speaker 3: I totally agree with what you said, and it reminds me of when I went to public policy school, a different one out on the West Coast. The main lesson was, "You should define the problem first and then work on the policy solutions." And when I got into the real world, I have found, at least in the renewable energy space, that policymakers never agree on the problem, but they can often agree on the solution. And so that has led us to the situation we're in. Sometimes it works out well. Sometimes you have policies that are not so good, as a result.

Question 11: To start with a question for Speaker 4, it seems like after we've removed the impact of the negative pricing anomaly in the data in your wind and solar study, your findings are driven by the fact that marginal prices are lower at night and higher during the day largely because you have coal in the margin at night, gas in margin during the day. There's no carbon pricing in your analysis. If you put carbon prices in there, obviously the price of coal goes up relative to gas and closes that margin significantly, possibly even fully. Have you looked at what the impact would be if you included carbon value?

Speaker 4: No. It's obviously going to vary by the part of the country. It's not going to do much in New England or California, but in the Midwest it will have an impact. My interest was not in carbon emissions.

Questioner: Thanks. And then to Speaker 1, I appreciate the revision on the capacity factor. I think you're moving the right direction. Just running through some of the assumptions there with turbines being installed today, a capacity factor of 40% is pretty typical for what's being installed right now with low-wind speed turbines. Even with low-wind speed turbines in parts of the Midwest I think we're going to see big bumps as those projects come online.

To continue going through the other assumptions, on the capital cost number, you use \$2,200 per kilowatt. We said \$1,630. You're right. The number last year was a bit low. It was a small sample size. If you use this year's number, which is basically the project is under construction now at \$1,750. That's consistent with what it was the year prior. So I think the number is well below \$2,200. That's where we were about five years ago. So that's one issue.

You mentioned the capacity factor issue. You're also assuming turbine life of 20 years. 25 is a standard assumption. And for both analyses, are you using Henry Hub gas prices for the gas price? The actual delivered price to electricity generators is about 20% higher. You're using O&M costs of $40K per megawatt per year for wind. The actual one is about $25,000, based on the Lawrence Berkeley National Lab (LBNL) data. All of this is from LBNL data.

And then with respect to construction time, you assume 1.5 years. The actual time is more like half a year. Sometimes you even have the financing as you're building the project, depending on who the developer is.

So putting all that together, I redid the numbers here. Basically, wind displacing coal comes out with benefits of $320K per megawatt versus a cost of $160K per megawatt. So wind is very strongly beneficial there with the $50.00 carbon price. On the gas price, I get $210K benefits per megawatt of wind versus $160K costs. So wind actually comes out ahead there. And that's even with today's gas prices. If you factor in gas price increases over time (The Energy Information Administration's *Annual Energy Outlook* has them going up by a factor of 50% over the life of turbines installed today)…Turbines obviously don't go up in price. And also, given the value of hedging against that price volatility I think wind looks very attractive.

In your old paper, the capacity factor of gas was relevant, and earlier you were making two arguments, basically, that new, more efficient better heat rate combined cycles will run at higher capacity factors. The most efficient gas plants run at 48% capacity factor. You're not getting to 90% there…

Moderator: At the risk of stopping the dialogue, we're not tracking it up here. Obviously there are some disagreements about data. Let me ask Speaker 1 for a quick generic response, and then we'll do further discussion offline if we can.

Speaker 1: Yes. Send me an email.

Questioner: OK.

Speaker 1: By the way, I didn't use the Henry Hub for most of the calculations. I used the EIA reported information. But I'll answer each one of those things in an email, and I'll send a copy of the model that I used so you can do an audit on the model as well.

Question 12: We've been talking generically about renewables. I want to break it down between utility-scale renewables and distributable renewables. We know, roughly, that utility-scale renewables are about 50% cheaper than distributed renewables. But we heavily subsidize distributed renewables. Is there a reason why that happens, if we're talking about, "Let's do the cheapest things first?"

Speaker 4: The answer must be political. People love the idea of distributed resources. Also, if you compare distributed renewables with the retail price, particularly in, say, California, with that rising tier pricing, it looks pretty good. George Schulz, the former secretary of state, has solar panels on his house. And he asked me just yesterday, "So why is this not a good deal?" And I said, "Well, the utility isn't actually saving that when you generate." So I think part of the answer is political. Part of it is that people are persuaded that it saves the utility losses, because it's right there. But, of course, if there's a lot of it, it requires the utility to reinforce the system to permit reverse power flows. So it's perceptual. It's political.

Speaker 2: I think that you're not giving enough credit to the support for distributed renewables, because I think you're saying political as sort of a dirty word. I think that there's demand from individuals, whether they be residential or business, to participate in this in a way that they feel like they're investing in something and there is personal investment in this. There are potential benefits system-wide from these, in terms of reliability, though it's questionable how much that will be and in what areas. We're just starting to look at pricing these things in a way that makes more sense. The greater Boston area is heavily transmission constrained. So solar on individual houses and businesses in Boston is very different than solar out in western Massachusetts. And I think you also have to be thinking that this is a stepping stone to a longer-term thing in terms of reducing costs ultimately. And I have a vision that eventually distributed forms of solar are going to be cost competitive. I don't know when that eventually will happen, but I think it will, and I think the kinds of things that we're doing now will get us there.

Question 13: First of all, the art of the possible is politics. So what Speaker 2 is doing, what other people are doing today is what is possible. And it always is a second best solution, if not the third or fourth best. But it's certainly trying to get at the best solution in the best possible way. The politics is forcing you down this road of economic job creation, but really only in the electricity sector because those are the people that show up to be heard in the political process. But the resulting price increases or whatever else you're doing in terms of tweaking the economies locally is affecting job growth overall. And so should we have a policy placeholder somewhere filed away for a more broad offset program to really bring the transportation together with the electricity together with a global solution? So that there is some context here for the start of a real solution in what you build today?

Speaker 2: I think you're absolutely right that there do need to be placeholders both on the small scale and the large scale. So for example, when we developed RGGI, as you well know, I think there was probably a pretty broad understanding that the cap wasn't going to be binding, and our thought was that this cap is a placeholder for a future cap, and when it became feasible to lower the cap, that is what we've done. The cap is now binding. The prices have gone up. But I think in order to get where you are, again, there has to be this integration, and I think, given the way that at least the agencies in Massachusetts are working together, particularly with the PUCs and particularly with the transportation agencies, there are several different placeholders that are going to work.

We're working on a regulation on greenhouse gases for transportation, for example, that's going essentially to be like a SIP (state implementation plan) that already exists for NOX. At this moment, it's probably not going to have a huge impact, but it will open the door for there to be this kind of integration. And when we talk about thinking as economists about this, let's remember, as Speaker 3 said, we're not talking about, "Where's the transparency for fossil fuel subsidies both historical and ongoing?" And I don't even know quantitatively how big they would be, but there's certainly nowhere on anybody's electricity bill that says, here's what you're paying for whatever the tax benefits are and, in fact, in Massachusetts there are those line items for renewable energy. We have lines that say, "X percentage of your bill, X number of cents per bill is for the renewable energy program." And that conversation is not happening here even in the studies that are being done. We're all intent on saying, "Well, that was a subsidized price. We'd add $20.00 to it if we took into account." Well, how come we're not saying, "Well, that natural gas or that coal plant's pricing…" I'm not even talking externalities. Where is that subsidy? And I think that has to be part of any of this kind of integrated thinking moving forward.

Comment: There is an EIA study of subsidies to energy in fiscal 2010. It makes the point that there are substantial subsidies to fossil fuels. Of course, per kilowatt hour or any other measure, they're much higher for renewables. But there are substantial subsidies.

Question 14: You're absolutely correct. The subsidies for fossil fuel and nuclear as well are huge, and they're just not quantified. I want to make one comment, and that is that the last resort generation technology which will be brought on when the economy grows and we find ourselves short of energy will be single cycle combustion turbines, and this will not be the first time that that's happened. This will be the third or fourth time that that's happened, because it happens via the cheapest capital cost kind of generation. And in that context also, the most reliable source of generation then you can have, it may not be cheapest but it will be the default.

I appreciate the earlier questioner opening the door on transportation, because that was really going to be my question. First of all, if you look at electric cars, they not only provide some help for wind in terms of being able to charge them at night (again, if the rate structure is right), but they do provide kind of a moving storage capability, 24/7, which ultimately can be helpful if there's enough penetration. So I was going to ask, in terms of the earlier suggestion about R&D. What, if you've thought about it, what fraction of a total R&D program would you devote electricity supply and what sort of fraction would you think would be appropriate to devote to storage and/or other forms of energy production, i.e. for transportation, like electric vehicles?

Comment: Well, I haven't actually thought about the percentages, because I've been mostly worrying about trying to raise the total. So, I mean, we should double or triple quickly what ARPA-E is spending and let them decide on what's the right mix of these technologies. My suspicion is this if I got out my pencil and we looked at this, and you think about this as a global problem not a US problem, then I would focus on supply technologies for providing electric power as being the first order of things that you really, you have to solve that problem, because of all the things that everybody talks about. I mean they're building those coal plants in China, and so on. And the sooner we can make that look uneconomic to them, the better.

Session Three.
Section 111(d): What Will EPA Do? What Will the States Do?

The regime proposed by the EPA to regulate carbon emissions for existing generation will require each state to adopt a State Implementation Plan (SIP) to meet objectives that the agency will set out. That much is certain, but there is a great deal of information that is simply unknown at present. Will the EPA adopt a systems-based approach or a source-based one? Some contend that EPA may adopt only a "source-based" approach, which would prescribe emission reduction measures that would be taken at only the affected sources themselves. What are the implications for the states and for the electric markets of the two approaches? How will emissions reductions be measured? As one law firm has noted, "the statute calls for performance standards to reduce emissions from existing stationary sources, but it does not prescribe the metric by which emissions reductions are to be measured." Within this framework, states might decide to regulate generators based on an emissions rate—likely on an emissions per megawatt hour (MWh) basis—or based on a statewide or plant-specific mass-based cap. What are the implications? How will the federal and state governments interact? The states retain substantial authority to shape the emission control program, including using market-based compliance mechanisms. What degree of specificity will EPA include in its guidance to the states? Conversely, what flexibility will the states be afforded? What are the implications of more or less flexibility being afforded the states?

Moderator: The topic, as you know, for this panel is the regulatory proposal from the Obama administration to reduce CO2 emissions by the year 2030 from the electric power sector under Section 111(d) of the Clean Air Act.

Some of the questions that you have and that the panel will initially address are surely going to be fundamentally legal. Others are going to be economic. Others are going to focus in on the feasibility of implementation. And then there are science and engineering, and then there are some broad policy questions.

Speaker 1.
I've been asked to provide a little bit of legal context or background for what I know is going to be a very energetic discussion today about 111(d) and the contours of EPA's authority to implement this program.

There are a lot of policy questions. I'm sure we'll get to those. I'm going to try to be the legal foundation for that conversation.

I also wanted to show everyone that I now never leave home without this ratty, three-page document, which is Section 111 of the Clean Air Act, because every lawyer knows you have to start with the text of the statute. And, while there are not that many words in Section 111(d), the words matter. So I have this here in case something comes up and I need to refer to it for answers.

To talk about EPA's approach and the legal risk that it has assumed by undertaking this approach, I really think it makes sense to take a couple steps back and consider the Clean Air Act more broadly and over time.

I just wanted to touch on four quick cases. They're not quick cases. I can spend the entire time just talking about those, but I just want to hit on some themes about statutory interpretation of the Clean Air Act. My takeaway here is that it is not as cut and dried as either side will tell you in the debate over EPA's authority to apply a more flexible approach to Section 111(d).

The first case is *Chevron*. This year was the 30th anniversary of *Chevron*. This is a watershed case for administrative law. It stands for the proposition that if a statute does not speak directly to the question at issue, that the review in court defers to the expert agency's reasonable interpretation. What's also interesting about this case was that it was the Supreme Court taking a look at the definition of "stationary source" under Section 111. This was not a 111 case, but at the time this was the only part of the Clean Air Act that defined "stationary source," and so the court was looking at it.

At issue here was EPA's bubble concept. EPA said that if you look at a facility, at an installation, there are any number of conveyances, pipes, smokestacks, that each on their own could be a major stationary source that each emit at least 100 tons per year of any air pollutant. But it was be administratively a lot easier to draw a bubble around that facility and for permitting purposes consider it one major source. Environmental groups challenged this. The court upheld this saying, yes, that "stationary source" could mean each one of those conveyances, but it could also mean any discrete but integrated operation that pollutes.

This opens the door to more flexible approaches to the Clean Air Act. Immediately on the heels of *Chevron*, EPA issues guidance about its bubble policy, but also about trading emissions, netting emissions, and emissions offsets including offsets from other sources in a source category, from other source categories, and even from sources and activities that EPA otherwise had no jurisdiction over.

Now, just because EPA can apply that flexibility in some portions of the Clean Air Act does not mean it can apply it in all. And whether it can apply it in 111(d) remains an open question.

In addition, courts are getting increasingly frustrated with EPA's interpretation of the Clean Air Act and its attempt to be creative, so these two quotes I have up here are by officers of the court who are quite likely to review EPA's 111(d) proposal.

The first judge, Tatel, was talking about EPA's arguments in the 2000s that it did not need to issue an endangerment finding for greenhouse gases. The second is by Judge Justice Scalia. He was writing for the majority on a case this summer about GHG permitting.

Disputes over Clean Air Act text have been ongoing for decades. It turns out it's as much about the context of the words as the text itself. Just as an illustration of that, in the case *Mass v. EPA*, this was again what Judge Tatel was talking about, whether EPA had to consider the public health and environmental impacts of greenhouses gases. EPA's position was that Congress did not intend for EPA to go after pollution that caused climate change. Therefore, carbon dioxide is not one of the any air pollutants.

That court said "any air pollutant" means *any* air pollutant. The statutory text forecloses EPA's interpretation. Full stop. So that seems pretty straightforward, but then you fast forward to this summer, *UARG v. EPA* and a majority decision. The court says "any air pollutant" means different things depending on where you see it in the Act.

At issue there was that EPA was trying to get around the fact that a "major stationary source" is again those sources that emit at least 100 tons per year of any air pollutant. Obviously, sources emit a lot more carbon dioxide than other types of pollution. This could have potentially swept in millions of new sources that would need major permitting for EPA. EPA was trying to write around that 100 tons per year standard, and the court said that you can't write around a number. There are some things that are clear and you really cannot dispute them. But you can read into "any air pollutant" that maybe it doesn't make sense for all air pollutants to be addressed in every Clean Air Act program.

The dissent took issue with that and said that basically the majority's come up with an a-textual solution to this problem. They've basically added 35 words to the Clean Air Act in order to reach the conclusion they reached. Now, the dissent said, if you're going to add those 35 words, we'd add them somewhere else-- and then there was a whole dispute on that and we could get into that, but we don't have time for that today.

The final example I wanted to show was another case from this summer, *EPA v. EME Homer Generation*. This is about EPA's good neighbor provision. This is a provision of the Clean Air Act that EPA has been struggling over for more than a decade. Last year the DC Circuit rejected EPA's second attempt to set statewide budgets for upwind states. The Supreme Court, however, reversed and upheld. At issue here was the word "amounts." You'll see that states are supposed to be prohibiting "amounts" of pollution from sources and activities that contribute to air quality problems downwind.

EPA interpreted "amounts" to mean cost and set budgets based on how many reductions each upwind state can make cost effectively. The word cost isn't there in the CAA text. The dissent said that in the past, when the cost hasn't been mentioned in a program for the Clean Air Act, we've ruled EPA can't consider it and now EPA has only considered cost to set these budgets. Nonetheless, the majority said that this made sense, it was practical, it was cost effective, and they were deferring to the agency.

All of this is to say that the latitude that courts give EPA on different Clean Air Act programs varies. This is not a black and white situation. The 111(d) program and the approach that EPA has taken to it is not a slam dunk for either side, which is what's going to make today's discussion so interesting.

So, on new source performance standards, section 111(d) was meant to be a technology forcing provision in the statute. That means that the standards are not set based on health. They're based on what EPA determines is the "Best System of Emission Reduction." EPA sets that target by looking across an industry and seeing what's being done to make those reductions. EPA is not allowed to mandate a technology or an approach. The idea is that a target is set, and then the industry can innovate and do whatever it wants to do to meet that target.

Now, there are two parts of new source performance standards. 111(b) is for new sources. EPA determines what the Best System of Emission Reduction is and sets the standards for those sources.

Under 111(d), on the other hand, EPA still sets or determines that Best System of Emission Reduction, but now it's the states that determine what the actual standard is for each of the existing sources in their states.

At the heart of this program is the definition of "standard of performance." You'll see it's a long definition. It has been changed a couple of times over history. In that parenthetical about the things EPA has to take into account, some of those factors have been added over the years.

In addition, in 1977, Congress added, for new sources only under this program, that the Best System of Emission Reduction had to be the best technological system of continuous emissions reduction. Congress then took those qualifiers out in 1990, wanting to make sure that there were more flexible approaches available for even the new standards under this program and in particular fuel switching.

In the left-hand column of this slide, these are the factors that were embedded in that definition of “standard of performance.” These are the things that EPA needs to consider when it's determining the Best System of Emission Reduction. In addition, on the right hand side, there are two other factors that Congress suggested both states and EPA consider for the existing source program. There is some agreement that this means there should be some additional flexibility afforded for setting standards for existing sources, because it's harder to retrofit sources and they're all different vintages and have different efficiencies on their own.

With respect to the rationale for the Best System of Emission Reduction, EPA said, “We looked at whether you could improve heat rate at EGUs (electricity generating units), and in particular coal EGUs. But we didn't stop there. We thought that it also made sense to look at utilization of fossil fired units and to see if there are ways you could shift utilization from high carbon intensity to low carbon intensity or zero carbon generators and/or to reduce demand across the system through energy efficiency.”

So EPA started its proposal with a 2012 carbon intensity snapshot. This is what we've started calling this. It is not a baseline. There has been some confusion this is a baseline. I think Speaker 3 has made this point before, that all this is is looking at the fossil fired sources in a state. It's not looking necessarily at the actual picture in any particular state.

So for states with lots of hydro or nuclear, that's not captured here. This is just a power over pollution ratio of the EGUs that would be affected by this rule.

EPA then took its Best System of Emission Reduction, which we'll turn to in a moment, and applied to that snapshot for each state to arrive at a 2030 target for each state. It also set a 10 year annual rolling average interim target for states to start to get folks on a glide path towards that 2030 target.

In the EPA’s Best System of Emissions Reduction, sort of the first approach that it put out there is all right, we're looking at the BSER as a series of four building blocks. They're based on activities we already see states and sources implementing to reduce their carbon. One is at the plant. It is improving heat rate through efficiency upgrades and good combustion practices. So Block 1is addressing the emission rate of coal EGUs.

The other three building blocks are all having to do with this utilization issue, so Block 2, having to do with shifting from coal to different kinds of gas plants, is a matter of then lowering utilization of the higher carbon intensity generators.

Block 3, which is giving some little credit to existing nuclear, which we could talk about, and to renewables, again goes to utilization across the electricity sector. And then Block 4 talks about lowering utilization across the board based on decreasing demand.

EPA takes each of those four building blocks and applies them to this power over pollution ratio that it has established for each state. It then gives each state a rate-based target of pounds of CO_2 per megawatt hour. A state may also, though, convert this to a mass-based goal. EPA doesn't give a whole lot of guidance on how to do this. So that's going to definitely be one of the major issues.

All right, so BSER options. Option one is, again, these four building blocks. The alternative option that EPA recognizes has to do with the idea of a fence line defining the limits of an EGU. States can opt to employ strategies inside or outside and EGU's fence line.

Recognizing this as legal risk, EPA comes up with this alternative approach, which is, "Look, we just wanted to look at two things. We focus on the EGUs, the affected facilities, and we look at how to make them run more efficiently and how to reduce utilization of those with higher carbon intensity. When we did that we saw what states are doing. We're not defining BSER by those four building blocks, but we're using those activities in the four building blocks to measure a possible target."

My time is up. Option two was that states fall back on just blocks one and two. And then I just wanted to make the point that compliance is different. Again, EPA is not allowed to mandate any sort of technology or approach, so states can do any number of those building blocks or other technologies in order to comply.

Question: What about this issue that there are two 111(d)s that passed and this question that's now before the DC Circuit as to which one controls, and all the rest?

Speaker 1: That is a great question. I think it goes a little bit beyond clarifying. I'd love to talk about it. I've been writing a lot about that and, yes, the fact that it is a live question right now in the DC Circuit makes it all that more interesting.

Moderator: Feel free to raise that later in the discussion. Any true clarification questions?

Question: A couple pages ago under the heading, "Proposal: Carbon Intensity Goals," there was a formula for calculating the 2030 state goal. In the denominator, in addition to "megawatt hours" of fossil, renewable, nuclear and energy efficiency, there's a "megawatts" of nuclear term. Can you explain what that's doing there?

Speaker 1: I'm going to call my lifeline, an energy fellow in my policy initiative who says he has an answer.

Comment: EPA gives credit to 5.8 or 5.9%, now I can't remember the number, of existing megawatts of capacity of nuclear. So, for any state that has an existing nuclear plant, EPA includes in their goal 5.8% of that capacity, so that's the megawatts.

And the megawatt hours is for the three states that are planning to build new nuclear units. That's Georgia, I think, Tennessee, and South Carolina. They have included the estimated annual production from those units in their goal… [OVERLAPPING VOICES]

Moderator: The answer is "typographical error."

Question: Does 111(d) speak at all to the necessity of a federal implementation plan or what it would look like? And number two, does it speak at all to what the consequences of state noncompliance would be, other than EPA just steps in and does it?

Speaker 1: Yes, in a number of pieces of Section 111(d) there's reference to 110, which is the program under which EPA sets national ambient air quality standards and then states come up with implementation plans for meeting those standards. So it says that if a state fails to submit a satisfactory plan to EPA under 111(d), that EPA can fall back on its remedies and 110(c), which includes issuing its own federal implementation plan.

Question: There's a slide in here where you're talking about the standard of performance and there's a clause in here about energy requirements. How have energy requirements been traditionally interpreted under Section 111?

Speaker 1: The 1977 Clean Air Act amendments were drafted, obviously, in the context of the energy crisis, so the word "energy" was included in the Clean Air Act, I want to say dozens of times in that particular set of amendments. Everywhere that there were going to be new pollution requirements, Congress wanted EPA to think about the energy consequences. I'm not sure that I can point to a past time when that made a difference in the Best System of Emission Reduction. Here, EPA relied on it in its setting of the block four and said that energy efficiency was a technology or an approach that did not require energy and therefore fit that mode.

Question: Would you go back to your last slide? Can you just explain this one more time, because it goes to this central question, which is, what is EPA's authority if states refuse to pass these plans? Maybe this addresses that, or at least starts to? Can you maybe elaborate on this slide?

Speaker 1: It might actually be that it's the previous slide that would do that more. This slide is saying that EPA's fallback approach here if they decide that there's too much legal risk with the four building blocks is that EPA really will just look at each EGU that is in this source category--so both natural gas and coal fired, and we'll look at ways we can improve heat right within the fence line and we'll look at ways we can shift utilization between those, so it looks more like a traditional trading program.

The alternative option one is another way that they were trying to make it appear more inside the fence line. Your enforcement question is a great one.

Speaker 2.
Some of you have heard some of my colleagues talk about the proposed 111(d) rule already.
I'm going to give you the economist perspective and probably pose some questions about the legal aspect of it, but also in addition, alas, I just couldn't help myself.

This morning I popped in another slide that we had previously put together before 111(d) was proposed to look at a potential way to comply that's not the traditional cap and trade.

To follow on Speaker 1's description, again, the Best System of Emission Reduction included four building blocks ,and I will talk about that.

Here's the timeline. As you can see, and as Speaker 1 also says, litigation will probably have setbacks for these, but these are the current deadlines. Actually the comments have been extended to December.

This is a graph of what the actual rule says. It basically says, "Look at the historical generation and look at the historical emissions from these covered entities, which are coal, natural gas, and oil units. And look at the emissions from a historical timeframe, 2005," and it's about a 30% reduction based on that equation that you just saw, which I will talk about too. Because of the reduction that has already been achieved, it's really approximately an 18% reduction, relative to the 2012 emissions.

Here are the four building blocks. First, increasing the efficiency at the power plant. The second is switching to a lower emitting resource, basically to a gas combined cycle. The third building block is building more low and zero emissions generation like renewables. It also considers the 5.8% of nuclear that are at risk. It does not count in the numerator or the denominator hydro generation. Then the fourth building block is energy efficiency.

First of all, if you look at the equation, anybody in the electric industry will recognize that this is not the traditional emissions rate. So it's not total emissions over total generation, it's only the emissions from the fossil units divided by the megawatt hours of the fossil units plus all the generation from the at-risk nuclear, the new and existing renewable, as well as an energy efficiency amount which is megawatt hours which would have been used had the energy efficiency not been implemented.

So the emissions standard for each state was built this way. It takes the 2012 number and EPA estimates how much of each of the building blocks each state can "accomplish."

What's interesting is that if you just looked at the equation and then you think about each state, if you reduce the megawatt hours associated with fossil fuel, you automatically reduce the emissions on the numerator as well. So having a rate-based standard doesn't necessarily reduce emissions, because you can increase your megawatt hours and increase the numerator, but your rate is still staying the same. Obviously, as Speaker 1 pointed out, converting that to a mass-based approach poses some challenges.

This is a lineup of the 50 states, minus Vermont, because Vermont doesn't have emissions from fossil.

State by state the top of the bar is the 2012 historical emissions rate given at EPA's calculation. Then the colored bars are what EPA estimates can be accomplished by each state. The red is the coal heat rate. Then the possible savings from gas combined cycle ramping up, and then nuclear, renewables, and energy efficiency.

The bottom of the bar is the 2030 emissions standards set by EPA for each state. You'll see, obviously, that the starting point for each state is different, but also the end point of each state is quite different.

So the bottom of the bar is quite different for different states, and in a way it's a little bit random. You have North Dakota, Kentucky, Missouri, and Indiana, with an end 2030 emission standard of about 1600 pounds per megawatt hour, whereas Arizona, South Dakota, Minnesota, Virginia, and Texas have a standard of about 800 pounds per megawatt hour, almost half.

So states, if you start comparing yourself to your neighbors, you get a very different picture. Similarly this next slide shows the percent reduction that's needed for each state as well as the total CO_2 emissions in millions of tons to reach that 2030 rate standard. Again, you can see the differences across the states.

This is what EPA has simulated as the shadow price, if each state were to comply on its own, to comply with the standard that EPA has set. I think EPA used the IPM model to simulate a system and each state would have to comply on its own within the boundary of the state.

These are the shadow prices of the carbon. You can see, again, it ranges from zero to somewhere close to, well there's $101, but aside from that there is about a $50 range.

Now I'm going to go into a little bit about what the implications of the rule might be. One thing is that it's clear that similar or exactly the same coal plants located in two different states with different standards could be treated very differently.

For example, state A has a 700 or so pounds per megawatt hour rate. If you use a $15 per ton of CO_2 price, the bid of the coal plant and the gas plant would be about $40 or so in this hypothetical example.

But then in state B, if the standard is less aggressive, which means allowing more tons of CO_2 per MWh, every time a gas combined cycle generates it in theory can generate a credit, so it can collect revenues from the credits and therefore can offer at a lower price.

This disparate treatment of similar plants located in different states is quite interesting. For those that operate the system, it's not clear how we can fit the square peg in the round hole, so to speak.

Another interesting thing is that if a new combined cycle plant is not covered under 111(d) (since 111d is for "existing" sources), if you install a new combined cycle plant, it's not considered under the compliance standard. It's not considered in the standard and it's not used for compliance, at least the way the rule is worded now. I know there's a lot of consideration of the wording in the proposed rules, so I think this is an issue that's still up for decision.

But it's also interesting that the exact same combined cycle plant may actually have an opportunity to offer different prices into the market, because an existing combined cycle can potentially offer credit by just operating. So it can get revenues from the credits markets.

There's another aspect of this that's also interesting. So we looked back into the IPM simulation, which is a capacity expansion simulation that EPA conducted that accompanied the proposed rule, and then we also looked at the building blocks that EPA used to set the standard.

Here are just a couple of interesting things. The building blocks are mechanically applied, and this is particularly true for the assumptions on combined cycle and renewables in some ways, because there is a very formulaic approach to estimating what each state can accomplish on their renewables side.

So economics are not really considered. Once you consider the economics, the actual compliance may be very different from the building block assumptions, even if you just stayed within the boundary. We're not even talking about collaboration. The states' compliance mechanism will be very different, because when the standards were set the economics weren't really considered. But looking back to how the standards were set and how EPA then simulated the systems, there are also some discrepancies.

One is load levels. The starting points of the net load are actually quite different in the standard setting calculation itself and in the simulation.

The renewables levels used in setting the standard also didn't really consider economics, in particular, not geographic differences. They took the average of RPSes in the states within the region--so if you're in PJM, it took the Mid-Atlantic area and looked at the RPS standards in those states-- but it only used states that had an RPS. If a state didn't have RPS, it wasn't counted. So they took the average of the percentage of RPS and applied it to all the states, and then assumed that every state can reach that renewables standard using its own renewables within the state. So it also has a state boundary.

It also didn't look at economics, so it didn't think about, for example how expensive wind in Pennsylvania is versus somewhere else. In setting a standard in a mechanical formulaic way, that's what happens, but there is some discrepancy once you start simulating what will actually happen versus what the standards are.

Another anomaly which is kind of interesting is if the standard for your state is lower than the emissions rate of an existing combined cycle plant. Say a combined cycle has an emissions rate of about 700 or 800 pounds per megawatt hour and your target rate happens to be below that, every unit of generation the combined cycle produces will actually increases your emissions rate. In that case, you have this strange incentive to get rid of your existing combined cycle and switch to a new combined cycle. This is what the simulation actually shows, because a new combined cycle plant is not covered by the compliance standard. So there are some anomalies like that.

Probably just about everybody here has heard me talk about collaboration, and I think we all agree that cooperation could benefit everybody. I think the best regional benefits can be achieved by setting a single carbon price across a region or across time or through cap and trade. Everybody here is probably familiar with cap and trade, but I'll give you some example of using carbon price to achieve carbon emissions reduction.

We also think, obviously, that all carbon emissions should be covered, including the new sources, including the new combined cycle plants already covered under 111(b), which, of course, has legal ramifications, but I'm not a lawyer so I don't need to address that.

Mass-based compliance would increase benefits--I think it just makes more sense. Obviously there are advantages to using a rate-base standard if the economy grows or decreases, but a mass-based approach makes a lot more sense from a reduction perspective, and it's also easier to manage for cap and trade purposes and pricing, etc.

Then, it would help to have some kind of regional uniform tradable product, whether it's CO2 emissions allowances or renewable efficiency credits.

There are some indicative estimates that have been published. MISO came out two weeks ago saying that there could be about $3 billion per year savings over the 10 years from pursuing a collaborative approach, and EPA has estimated some benefits as well for collaboration. Obviously the estimated benefits will depend on what you're comparing to—what type of compliance mechanism you would be using, versus what the regional compliance approach would be.

A couple more notes before I end this. Coordination is tricky, but really desirable. We've already observed in many forums when we were speaking about this, this temptation to go it alone. Especially for states that have relatively lenient standard, for which it would be quite easy to achieve those standards on their own. But, in theory, all states can be better off by collaborating.

The psychological "fairness" factor can get in the way.

Another thing that gets in the way we heard yesterday very clearly, which is that states want to make investments in-state to create jobs and economic growth, etc., so there's a tendency to comply on your own, using the economic engine within the state.

Then, lastly, there's also this idea that for collaboration to happen state A has to be able to pay state B. I'm not clear how that could happen. I'm not sure which agency is going to pay which agency. Is it going to go back to the rate payers, because ultimately rate payers are paying higher costs of power, etc? So I think I also need some legal advice on that.

I have a couple of other comments but I think I'll hold them off until maybe through the discussion. Thank you very much.

Question: Could you comment on the difference between the rate-based and mass-based standards in terms of their impact on power prices?

Speaker 2: Yes. It appears that if it's a mass-based standard, if we use carbon price then every unit of emission would have a price associated with it, so it lifts up everybody's bid, so to speak, if you added that adjustment to the price.

Price will increase. But with a rate-based approach, in theory, every time combined cycle generates in theory it could also generate a credit if the standard is higher than a combined cycle emissions rate. So the combined cycle actually can bid at a lower price. In theory, the price effect on the wholesale market would be lower with a rate-based approach, but I'm not suggesting that's a better approach. I'm just saying that if you just strictly looked at that rate-based approach in theory, some generators can generate a credit, and therefore they can collect revenues outside of wholesale energy markets.

Question: In your slide that showed the shadow prices for carbon from the integrated planning model that EPA used, can you speak to the methodology? How did they come up with those?

Speaker 2: We dug a little bit into the IPM inputs and outputs, but obviously we didn't rerun it. My understanding is that with respect to the state by state compliance cost estimates, it's a capacity expansion model. For each state it set the standard as a constraint. They do a long-term capacity expansion so it allows it to retire a coal plant and add a combined cycle or renewable plant, if they are economic. That's the shadow price on the constraint on the carbon rate based approach.

Moderator: I didn't understand when you said that states would be paying other states under the cooperation approach, because my understanding would be that under a multi-state plan either a group of states would put forth a single cap and trade system, in which case the trading is source/source, company/company. God knows it's not states. Or, they would have separate cap and trade systems and then choose to link them by bilateral recognition of allowances, as California and Québec, for example, have done.

Speaker 2: That's true. I think if you consider a nationwide or regional cap and trade you can trade carbon credits if it's a mass-based approach and you have a certain cap.

I guess what I was thinking about is if you had another approach, and you're negotiating with another state on the rate-based approach. You would have to figure out a way to compensate each other so that everybody is better off than going it alone.

Speaker 3.

Thank you for including me. As everyone knows, there's much to say about 111(d) and there's a lot that I'd like to say, but I only have 12 to 14 minutes, so I'm going to make just a few key points.

The first point is this. For reasons that I'll get into later, it is very unlikely that this approach will actually be implemented. But there's no guarantee.

Without revealing attorney/client privileged discussions, what we counsel our clients is that the chance that this actually is implemented is very low, but it's not impossible, so you have to plan for two scenarios. You have to plan for a scenario in which this proposal is not around, and there continue to be discussions in Congress about possible climate change initiatives. But, at the same time, we are encouraging people to work with their states, because so many of the decisions are made at the state level, and also with EPA to talk about some of the practical implementation issues.

Even if you believe, as I do, that the rule is unlawful and will be struck down in court, it still behooves you to spend a lot of time understanding these implementation issues, because I do think EPA does not want to hear that its proposal is illegal, but they do want to hear about how this could really work in the real world. And I think they're quite interested in that, and I know states are as well.

That's my overall point. Then I have kind of four sub-bullets.

I have spent a lot of time working on the Clean Air Act, and I've been involved in several different presidential transitions. I will tell you this. There are many rules that are very difficult for a subsequent administration to overturn even if they don't like them. For legal or practical reasons, a new administration comes in and it almost always has to implement the rules that were adopted by the earlier administration.

This is not one of those rules. It would be very easy, legally and politically, for another administration to come in and just withdraw this proposal, and again, as a dyed in the wool Republican, I have a hard time seeing who might win the election, but anybody I can imagine would certainly come in an undo this proposal. And at that point, it'll probably still be in the court. So, politically, practically, it would be very easy to undo.

And the other political point, of course, is that it won't be the Obama administration that's making all the difficult decisions--I mean it's one thing to put out these kind of goals, but the rubber doesn't hit the road until states have to develop plans and EPA has to approve those plans. So it will be some other administration that will be doing all that.

The second point, before I get into the legal issues, is that there is simply no way that this rule can be implemented on the schedule that EPA has proposed. I think EPA understands that, and people say, “How can that be? EPA says there's a deadline. If there's a deadline, states will have to meet it.” Let me tell you that there are dozens and dozens of deadlines in the Clean Air Act that just cannot be met and are not met. So, for example, every time EPA revises or set a new air quality standard, states have a legal obligation to submit an implementation plan to comply with that standard within three years. That's in the statute.

Do you know how often states actually do that? Almost never. And it takes years and years to develop these implementation plans, and those are plans that are actually relatively simple compared to restructuring your entire electricity system.

Just as a practical matter, states will not be able to prepare and present their plans on this time line. EPA is going to have a heck of a time reviewing 50 different state plans, and to decide whether or not to approve them, they have to go through a notice and comment process. That's 50 different notice and comments processes.

So they have to evaluate these state plans. They have to decide whether they're going to approve them, or whether they're going to approve them in part. They put that out for public comment. So, as a practical matter, the timing here just will not work. Cannot work.

My final point is this. In virtually all rules that we've seen in the last 20 years where there's some state plan obligation, at least dealing with the power sector, when EPA puts it rule out it says, “States, here's what you have to comply with. Please submit your plan. And if you don't submit a plan, here's what the federal implementation plan will look like.” So states have a real option. They can say, “Well, do I want to go to the trouble of coming up with my own plan, or do I want to accept the federal plan?”

EPA didn't do that in this case, because EPA has no idea how it could possibly impose the requirements that it wants states to impose. So, every time (you'll notice this if you ever go to a conference with Gina or with Janet McCabe, or others) someone will ask, “What would a federal plan look like?”

The answer is always some version of this: “We're confident that when states really look at this plan, they're going to want to implement it, so we're confident the states are going to submit their plan.” EPA has no idea how it could legally impose really anything other than building block number one.

I thought Speaker 1 did a very fair job of presenting the legal issues. I want to come back to the statute, but I also want to start out with *Chevron*, which is kind of the seminal case that talks about how courts are supposed to review all agency actions, in particular under the Clean Air Act.

It says that courts are supposed to use traditional tools of statutory construction to determine whether Congress spoke to the issue, right? That involves reading the words of the statute, but it also involves looking at the context of the statute. And the courts have said that many times.

If you look at Section 111, it's absolutely clear that what EPA has proposed here has absolutely no relationship to what they can do under the statute. Let me just explain that, if I can, briefly.

Section 111 is actually very simple, and it all starts with EPA identifying specific types of facilities and putting those facilities into different categories. EPA has identified dozens of different facility types. In the power sector, they've actually subcategorized it into many different types of facilities, and they do that because when you look at the Best System of Emission Reduction that can be applied to that type of plant, you end up with very different allowable emission rates.

This, for 40 years, since 1970, has involved figuring out the type of plants, dividing them into different categories based on the allowable emission rate that can be achieved, and then EPA sets a standard of performance for each individual plant that each plant has to meet. They do that by looking at the degree of emission reduction that can be achieved through the application of the Best System of Emission Reduction that has been adequately demonstrated considering cost. It's all about the application of a system to an individual plant and the allowable emission rate that can be achieved. Speaker 1 is right. They never mandate a technology, but they set an emission rate that's based on a technology or a system of operation that they have identified. That's what a standard of performance is, and we know what a standard of performance is because EPA has set dozens of them since 1970. And all of them are exactly as I just described. I mean, sometimes there's work practice standards, but it's an allowable emission rate that a facility can meet.

People have said, "Yes, it's different with existing plants," but it's not different. EPA sets a standard of performance for new plants, and then they can require states to set a standard of performance for any existing source that would be subject to a 111(b) standard if it were a new source, right?

So EPA sets a standard of performance for new plants, and then states are required to set standards of performance for existing plants based on guidance from EPA. But it's the same thing. It's a standard of performance.

Interestingly, the statute also says in Section 111(d) that EPA shall permit states when applying a standard of performance to any individual source to take into consideration among other things the remaining useful life. But it re-emphasizes the point that these are standards that are applied to an individual plant.

That's basically the way the statute works and, as Speaker 1 said, EPA has said we can do something broader than that based on the definition of a standard of performance because, as Speaker 1 pointed out, a standard of performance is defined in part as the degree of emission reduction that can be achieved through the application of the Best System of Emission Reduction that has been actually demonstrated.

EPA has focused on the word "system." They said the "system" can include all kinds of different things, right? In this case it can include heat rate improvements, re-dispatch, etc.... All of that is part of a system, and that's absolutely true, but that's not the key part.

There's no debate over what a system may be. It talks about the application of a system and it's very clear that the statute is talking about the application of a system of emission reduction to individual plants, to individual sources.

That's the way it's worked for 40 years and that very same language is used in other parts of the statute. For example, if you go through a new source review program, you have to meet the Best Available Control Technology standard. The definition of a best available control technology that applies to a plant is something that can be achieved through the application of the Best System of Emission Control. It's the application of a system to individual power plants. That's really what EPA is limited to.

There are actually two complementary definitions of the term, "standard of performance." A standard of performance also has to ensure a continuous emission reduction from the plant being operated. That's in Section

321. That applies to new sources and existing sources.

It's very clear from the statute that this system has to be something that controls the emissions of a plant when it is being operated. For that reason alone, I think that this is simply not a standard of performance, and it's actually kind of surprising to me. Some of you are familiar with the NRDC proposal. Although I have been and continue to be critical of that proposal, I think that's much more legally defensible than what EPA has done. Because NRDC actually figured out a way to apply some things to each individual plant. EPA has taken that language and has said, "We're going to apply this not to the individual facilities, but we're going to apply it to the state as a whole."

The application of a mandated emission rate to the state as a whole is computed in kind of a bizarre way in terms of what's included and what's not. But it's way beyond anything that anybody has tried to do under the statute before.

I do want to explain, though, why I think EPA has done something that they know has enormous legal risk. And the answer is, because if you don't do something like this, you can't do very much. If EPA does what it's allowed to do under the Clean Air Act, you don't get very much by way of emissions reduction. That's the problem that the agencies have run into.

When I make this point, I use this example. We all talked about the President's announcement that there were going to be GHG requirements for new and existing sources. That very same announcement was made three years before by Lisa Jackson when she was the Administrator of EPA.

Some of you may remember that there was a lawsuit and there was a settlement agreement and under that settlement agreement with a number of states and environmental groups, EPA committed to doing a GHG standard for new and existing power plants and a GHG standard for new and existing refineries, all of those by the end of 2012.

2012 came and went and they hadn't done anything, and the reason was that when they went out and started to look at what they could actually do, it turned out to be very difficult to get anything in terms of emissions reductions.
So I think the administration, in order to have something that was credible internationally, in order to have some that could be part of the President's legacy, has had to use something that goes way beyond what the Clean Air Act allows.

In my remaining two minutes let me just talk briefly about two of the building blocks that I think are particularly problematic. Building block two is innocuously called "re-dispatch." But, as a legal matter, it's a remarkable thing to think that EPA has this authority. For example, think of two plants that make widgets and those plants are roughly similar in age and over the years EPA has set different standards as technology for controlling emissions and water effluent and other things. EPA has used the very Best System of Emission Reduction that can be applied to plant A and to plant B. Here we come five years later to these plants that are completely compliant with all their environmental obligations, and EPA says, "You know what? We just want to take business from one plant and give it to another. That's our emissions reduction scheme, We're going to take a certain amount of business from coal plants and we're going to tell states we're going to transfer it to other plants. You can figure out how you do that."

And, of course, a whole other question is how you would do that without a carbon price or an allowance price. But EPA does not have the authority essentially to say, "We're going to take business from one plant and give it to another."

Another word on building block four. Everybody, I think, including me and my clients, supports the idea of energy efficiency. So, building block four, and there's lots of question about how aggressive it is, is again fairly innocuous. But remember, Section 111 applies not just to power plants but to every kind of production manufacturing plant. If EPA can require demand reduction measures for power plants, think of what they can do for refineries.

Could they say to a state, "We think the Best System of Emission Reduction to reduce GHG emissions is, 'State, you need to invest in more mass transit. You need to invest in bike lanes because those things will reduce the demand for those facilities and thereby reduce emissions'"? That is simply entirely inconsistent with the authority that EPA has.

Question: Could you just discuss why you think this rule would be particularly easy for the next administration to overturn?

Speaker 3: Yes. By the time the new administration comes in, a few states may have submitted their plans, but most will have not. So although the private sector is always planning ahead and looking at other things, there are no compliance obligations that anybody will have until well into the future. So by the time the new administration comes in in 2016, there's no practical reason that they couldn't just pull the plug on this, nor is there any legal reason.

There is nothing in the Clean Air Act that sets any kind of a deadline for issuing 111(d) standards. It does say that once the EPA issues a 111(b) standard, under certain circumstances it's required to require states to do something under 111(d). But there's no timeline on that, right?

It could be five years. It could 10 years. It could be 20 years. So there's no legal reason that EPA has to have a 111(d) standard. There's no scientific basis for this. This is all kind of amorphously technology driven and so, just as a practical matter and a legal matter, it's very easy for a new administration to come along and just withdraw the rule.

Now, it would have to go through notice and comment rule making, but that would take a matter of two or three months to propose to withdraw it and then to finalize that withdrawal.

Speaker 4.
Thanks. It's an honor to be on this panel and I appreciate Harvard for inviting us and welcoming us here. I really appreciate that and of course I appreciate all of you being here to listen to us talk.

I realize that not all of you are lawyers. In fact, relatively few of you are, so I'm going to avoid, to the extent I can, going into the legal details certainly beyond what we've already got presented really well by Speaker 1 and to some extent by Speaker 3.

I will touch on some legal issues, but a lot of what I want to talk about are some practical issues and some broader issues here. To the extent that you do have legal questions, I'll try to answer them in the Q&A period.

Speaker 3 and I agree about some things and disagree about others. I think I'll start out by saying that if this rule making were passed in the form it is today or in a final form that's more or less like it is today in terms of stringency, the kinds of reductions it's aiming at getting, I don't think it would be inaccurate to call it the most important environmental rule making since the 1990 amendments, with all due respect to the many rule makings that Speaker 3 was a part of while he was at EPA. I think it even wouldn't be a stretch to say it's the most important one since lead was listed as one of the criteria pollutants back in the late 1970s.

That said, it will be litigated. It has serious practical flaws in the form that it is in today. I'll talk about some of the ones that I see, but of course you heard about some of the other ones already.

I think where I disagree with Speaker 3 is that I don't see a plausible path forward where there's no rule. Or if I do, I at least don't see a plausible path forward where this set of sources doesn't have its carbon emissions regulated.

I think that's an important sea change. I think if you're in this industry, if you're a utility, if you're running a coal plant, your future prediction has to be that emissions from these plants are going to be regulated in some way. How much is not clear, because it's not clear which of these building blocks will survive and how their stringency will change. That sounds like I'm disagreeing with Speaker 3, but if you take maybe the weak version of his argument that this isn't going to survive and say, “It won't survive in its current form,” I couldn't agree with him any more strongly than that, because I don't think the final rule will look exactly like the proposal. In fact, it may look very different.

The key issues here really are stringency and flexibility. How tight is the rule going to be, and how much flexibility will be available to comply with it? “Flexibility” meaning, can two similar plants trade with each other? Can two different plants trade with each other? And then, can we bring in things like renewables and energy efficiency, which really essentially breaks down to your building blocks there?

The debate over how that flexibility is going to work and whether it's legally permissible under the statute has really focused a lot on this “Best System of Emission Reduction” language that comes out of the definition of a standard of performance in Section 111(a).

That is important language. However, that language talks to you about stringency, not about flexibility. The “Best System of Emission Reduction” gives direction to EPA, or in this case to the states, about what factors they can consider in determining how stringent the standard is.

It doesn’t say anything about what you can do as a source to comply with it. That's implicit in the fact that we're talking about performance standards here.

Even if you have the traditional technological understanding of a performance standard, the way it works is that your regulator picks a technology and says, “We think that's the best one based on all the factors that we're allowed to consider in the statute. Therefore, we're going to use that to set our stringency, our target. And then if you're an emitting facility, you don't have to use that technology if you don't want to. You can use any technology you want, or maybe a work practice, to comply with it as long as you meet the target that's set by EPA.”

That reflects the availability of information to the regulator. The regulator has some information, but is self-aware. An intelligent regulator realizes that he or she doesn't have full information, so it gives some freedom to the source. It's a compromise, to some extent, between a trading program and a command and control rule that says, “Install technology X.”

So the statute doesn't really give us any guidance at all about what sources can do to comply. And it gives us even less guidance in the existing source context because there's another layer here, that of what EPA is allowed to approve insofar as what states do. And the statute doesn't really give EPA much guidance there, either.

So I think this puts us in a world where we talk a lot about how thin the statute is, how short it is, how rarely it's been used, how there's not a lot of precedent here, and all that's true, but I think there is even less here to go on than even that implies. We're almost completely unmoored, in terms of what compliance options are available to facilities. There's very little guidance in the statute. What there is, in fact, gives us more options rather than fewer.

If that' true, if the statute is truly silent on these things, your traditional doctrines of statutory interpretation, at least post-*Chevron,* say EPA gets a lot of deference on this. Therefore, if the statute is silent and EPA is in favor of flexibility, as it appears to be, and the states are too, which they may be, then you are going to get a lot of flexibility, because that is something that's delegated to the agency.

In other words, if you want this rule to survive in its current form, then you want, actually, less statutory text, which is a bit of a paradox, but that's maybe true. But then you may have some reservations about that. There are certainly some on the Supreme Court that do. Justice Scalia has said twice in major Clean Air Act cases that he's highly skeptical of wide-ranging statutory programs or wide-ranging agency programs that regulate a large industry based on thin statutory text. He said that in *American Trucking versus Whitman*, and he said that recently in another case. Certainly there are votes on the Supreme Court for this idea that thin statutory text can't be used to implement a large regulatory program that covers a lot of the economy. So while that sounds like kind of a Hail Mary legal argument (I wouldn't want it to be the first one of my quiver), there's some support for it on the Supreme Court, and I think it's worth considering.

Let me talk a little bit about flexibility and the history of it. It used to be true that the industry was in favor of flexibility and greens weren't. That's the issue in *Chevron*. That's changed. Greens have wised up a little bit here. They've realized that the pie can get a little bigger if you allow flexibility, but they also want a bigger slice of that pie. In other words, to put a finer point on it, they want to consider flexibility not only in compliance but in the stringency setting process.

Industry's reaction to this development is mixed. I think there's still a lot of basic support for flexibility, as there always will be in industry, because of its cost reducing ability. But to the extent that flexibility upsets the status quo…if you're a coal plant and you can trade with another coal plant within your fleet, that's great. That's flexibility. But when you've got to pay a gas plant to run, or when you've got to pay for energy efficiency, or pay for renewables, companies tend to get pretty skeptical about that, and you can see that in the way that they feel about some of these options.

Let me close by talking a little bit about some of the problems I see with the rule as it's proposed. First of all, I'm not an economist and I'm not an electricity system modeler, but when I talk to my friends that are, they really point to this margin between coal and gas as being the cheapest opportunity to reduce emissions, at least from the fossil fuel sector. That may not be true and even if it is true, it may create risks of reliance on one fuel type. I make no comment on that now, but they certainly suggest that this margin is really what's important.

With respect to Speaker 3's point, it does involve some tradeoffs here. That involves essentially coal plants running less and gas plants running more, with attendant economic impacts that Speaker 3 mentioned.

With respect to Speaker 3's suggestion that states acting under the authority of the Clean Air Act don't have the power to change the dispatch like that, I don't think that's true. I think, first of all, that EPA could and in my view should group coal and gas into one source category, and then you don't even have this inter-source category trading.

I see no legal reason why they can't do that, and it would simplify compliance with the rules substantially if they did that. But even when they do that, you're still going to have these tradeoffs between coal and gas. I don't think that's in any way illegitimate or in conflict with the basic structure of the Act.

The basic structure of the Act, as it's been used for the last 40 years, already involves those kinds of tradeoffs between different kinds of coal plants. The division between different kinds of coal plants and coal versus gas seems to be a feature of the fact that EPA has defined the source categories as they have in the past, not something that's embedded in the text of the statute.

So I think EPA should group coal and gas together. That's one of the four things on my wish list. I think that would substantially reduce the legal uncertainty with trading between coal and gas.

We've heard about this treatment of new gas. It's a paradox here. It's a really puzzle. EPA has said that they're going to give states the authority to decide how to treat new gas, but there are limitations in the statute on how to do that. It's not clear what EPA wants. If states take inconsistent approaches it's going to be difficult for their plans to work together.

Again, according to the electricity modelers that I know, the construction of new gas may even trump increased utilization of existing gas, as far as a low cost option to comply with this. In some sense I suspect that that's the elephant in the room here, and there's almost nothing in the rule making about how that's going to be treated. I think EPA needs to do a better job on that.

Then, finally, having moved to South Carolina recently, in DC you hear that states are worried about this rule. In South Carolina you see it. I was in a meeting in Atlanta last weekend with a number of air regulators and people in PUCs from around the southeast and also around the country, and they agree with Speaker 3. They don't think that it's possible for this timeline to work.

There's a lot of complexity here in state environmental regulators dealing with PUCs and dealing with other parties in the state that they don't traditionally have either a great working relationship or any working relationship with. Sometimes that relationship is great, but even if the relationship is great, maybe the ability to work together on something this comprehensive to really change the way the electricity sector in a state works in not there. Certainly, not in the timelines that we're talking about. And you add on to that the requirement, or at least the powerful incentive, to work with other states, and it's very difficult for states to do this.

States also get some political blowback, because the different standards set for each state, the different rate limits, are perceived as an inequitable division of the burden to comply with this rule.

That may not be true, but EPA can and should do a better job of articulating the principle behind giving states different rates. Is the goal to make the total cost the same? Average cost? Marginal cost? Is it to reward early action in some way, plus those factors?

You hear a lot of rhetoric from EPA on this, but there's no clear articulated principle that a regulator in a state or a supporter of this rule can take to people and say, “Look, this is why our target is so different from this other state across the border.” And I think it would greatly help EPA to articulate that.

That's four things that I hope are in the final proposal that aren't in the current rule. There's some evidence that EPA is moving in that direction, although I'm skeptical about whether the schedule will change. Of course, the litigation may change it, but I'm skeptical that EPA will change it of its own accord.

Certainly I do think this rule will survive in some form, but I agree for a lot of the reasons that Speaker 3 mentioned that that form will look very different than it does today. It’s difficult to predict exactly what its final form will look like. I certain hope it will adjust in at least these four ways that I suggested. I'm sure it will adjust in other ways. Thank you.

General Discussion.

Question 1 (Moderator)*:* Before we delve into what I know is going to really very quickly get into the fascinating weeds of the legality and other aspects of the Section 111(d) regulatory proposal, I'm going to take the liberty as the moderator to ask a question, because in all this interesting discussion we've had, I don't think I ever saw the phrase or heard the phrase, “global climate change.” Maybe I missed it, but that's what this is in principle about. It's a result of a lawsuit, *Massachusetts v. EPA*, an endangerment finding that had to do with global climate change, etc.

One of the facts about climate change that stands out, certainly from an economic perspective, so to an environmental economist like myself, is that this is a global commons problem. Greenhouse gases mix in the atmosphere, although not uniformly. Therefore, for any individual jurisdiction taking action, they're going to pay the costs in taking action, but the climate change benefits are going to be distributed globally, and hence for any jurisdiction, even as large as the EU, the climate change benefits received by the jurisdiction are likely to be smaller than the costs that are incurred.

Given that, when the rule came out and on the very same day a regulatory impact analysis (RIA), 475 pages long, was released, I was curious naturally to see how the administration would economically justify the rule. What I saw was that if you take the administration’s numbers for the costs of compliance, their mean estimate for 2030, and their mean estimate for benefits, translated for the United States (which is the way every regulatory impact analysis that I know of has been done going back to Jimmy Carter, focused on the United States' citizens and residents or US geographic borders), the anticipated benefits are smaller than the costs--confirming the economic intuition. It's not a big surprise.

But the RIA doesn't stop there. It includes global benefits, benefits to other parts of the world. There are certainly ethnical arguments that can be made to do that, but it's a departure, maybe not from legal precedent, but from informal precedent, of how we do RIAs. So that somewhat surprised me.

Even that isn't where the major benefits come from. The real benefits come from reductions of other pollutants as a result of less use of coal, in particular particulates, PM2.5. From the analysis that EPA uses, which I'm sure people in this room would debate, in terms of the epidemiology and the toxicology, particulates have very high mortality impacts and therefore value of life analysis comes up with some big numbers. That's how we go from what I guess you could say would be a conventional regulatory impact benefit cost analysis, which would be negative $6 billion per year net benefits, making the US worse off, to positive $67 billion per year that is the mean analysis in the RIA.

When I wrote this up, people then sent in comments. It was at my blog. Those who were supportive of the rule wrote comments that said, “See, the author has shown that this rule makes a lot of sense.” Those who were antagonistic to the rule wrote in and said, “See, the author has shown that the rule doesn't make any sense.” So that's the question I want to pose to the panelists. What do those numbers mean to you, if anything?

Speaker 3: Can I go first? As someone who is a consumer of RIAs, and was a producer of RIAs when I was at EPA?

Point number one is this. None of that matters from a legal perspective, obviously. Now, it does and should matter to the public.

The second point I would make is this. Every single action that EPA has taken, at least under the Clean Air Act, since 2001 has been justified by PM2.5 benefits. Right?

Questioner: Right.

Speaker 3: I mean, no matter what you do, you can find enough PM2.5 benefits to justify it. Amusingly enough, even the reduction in the ozone standard, right? I mean, they can see that reducing the ozone standard itself, there would be more cost than benefits, but the co-benefits of reducing PM2.5…

I have a problem with that for lots of reasons, and that troubles me more than the global versus domestic issue--I mean, at least there is, as you say, kind of a moral argument, if not an economic one, and the theory of course is (and I think this is the administration's view), that if we take this action and show leadership, then others will follow along. They will also take actions that will benefit us, even though the costs will be borne there. Now, the jury is out on that and that remains to be seen.

EPA goes through a very extensive scientific process and says, “If your PM concentrations are below this level, then the public health is protected with an ample margin of safety. That's the PM2.5 NAAQS (National Ambient Air Quality Standard). As I say, they go through a very extensive scientific process, and then they do these rules.

In this case, like 98% of the benefit comes from reducing PM2.5 in areas that already meet the standard. So on the one hand EPA says, “If you meet the standard public health is protected with a margin of safety even for sensitive sub-populations” and then, in these rules, they say, “Tens of thousands of people are dying because they're exposed to levels that are below the standards that we said are safe.”

Anyway, the use of PM2.5 benefits to justify everything, whether it's an ozone standard or a toxic standard, is something that I find troubling for a number of reasons.

Speaker 4: I share some of Speaker 3's skepticism. Even the parts that I don't share, I understand how it resonates with people--that there's this fear of sleight of hand or fear of double counting when you use these PM2.5 or other conventional pollutant benefits to justify other rules.

I think if that's your view you do need to be a little bit careful about what you wish for, because if EPA is finding these benefits below the PM2.5 standard and therefore that standard is illegitimate, there really just needs to be tighter standards. Maybe you can't go and justify a bunch of other rules with it, but the green critique to this is that you can make a collateral attack on the PM2.5 standard and say, "Go revise it."

The problem is that it's really hard to revise the NAAQS. We've seen a lot of fighting over the ozone standard. Some of those standards haven't been revised in decades.

Comment: They've all been revised under this administration.

Speaker 4: They've all been revised? OK, I stand corrected. I guess, just be careful what you wish for. You may be better off, depending on where you stand, what your industry is, if you keep the PM standard where it is, and then have these other rules that may or may not be justified by those benefits there.

Again, as Speaker 3 said, this has relatively little legal relevance. There's an argument that EPA can't or shouldn't use the global benefits in its cost benefit calculations. I don't know where I stand on that. It's a really interesting legal topic.

Question 2: First, I want to say I very much appreciate this panel and I learned a lot this morning. I thought it was actually quite helpful in sort of understanding where we're coming from, and so on. I'm eager to have a conversation about the details here.

I wanted to step back and ask a forest question, not just about the trees, but the forest here, so I can get it off my chest, at least, and get your reaction to it.

I understand what we're trying to accomplish here and I know about the realities of second best that we were talking about yesterday, and pragmatism, and all that kind of thing.

Eventually when you go down that path, at some stage you start crossing over the line into the surreal where words mean what the Queen of Hearts says that they mean and they don't mean what everybody thinks they mean in normal practice.

What I want to know is, why hasn't the proposal the EPA has put forward here for Section 111(d) crossed well over into the surreal, where it's validating the worst accusations of the Tea Party types about the hubris of government and the attitude of, "I can say anything I want to say? I can call it anything I want to call it? I have a restriction to have an emissions rate standard and I can put anything in the denominator I want to?" That undermines the credibility of EPA in the long run. It sabotages the whole enterprise that we have going on here. Why isn't this an example of having gone too far in that way? Is this likely to lead to a backlash and just validate the worst fears of the right?

Speaker 2: Let me just start. I don't know if I have a full answer, but I guess I want to concur, because the first reaction I had was, is this a missed opportunity, right?

Because everyone's anticipating a rule to come out to regulate existing sources of greenhouse gas, and as someone said, it is the most complicated rule. It has unintended consequences. It has unintended ramifications.

So I do feel like it is a missed opportunity. EPA had an opportunity, and even though we knew it was going to be legally challenged, it seemed like it should have done a much better job, and maybe Speaker 4 had pointed out a few things, but also just the people in the electric industry know that there are some things that are completely impractical.

I think EPA could have avoided that. So I feel like it is a missed opportunity.

But I also have another sort question that I just can't help but ask. If EPA is going this far, could EPA have just said, "Let's have an X% reduction," instead of giving each state a particular standard, which now creates this unfairness issue, just because I got a different standard than my neighbor and, as Speaker 4 said, we don't know why. There's no principle behind it, except this mathematical application of the numbers, so it's sort of a half answer, but also a question for the others to simultaneously answer if you could.

Speaker 3: EPA didn't do that because that would have been even more legally problematic. I mean, if you just did a percent reduction by state, you have baseline problems. You have all sorts of equity problems. Some people have already done much more than other states in terms of reducing their emissions.

So I think EPA chose this because they actually think it is more equitable. Now, you might argue with how they've applied the standards, but I think their view is that, "At least we tried to do it the right way. We looked at where people are today. We roughly tried to make the marginal costs consistent across states…" and they didn't express it that way, but I think their view is, "We tried to do it in a fair way, recognizing that all states are in very different places." As I say, I think that's legally crazy.

Speaker 2: Just to follow on that. If EPA had done a percent reduction as opposed to state by state different reduction standards, it could still set aside credit for certain early compliance or early actions and things like that. And you could still use the same Best System of Emission Reduction.

Moderator: Let's turn to the original question, which is fundamentally political, and, Speaker 1, you've spent a substantial amount of time working with Congress, so tell us about that.

Speaker 1: I will just try to characterize what EPA's position, I think, would be here. That is that this was not an unbounded exercise in regulating carbon emissions.

There are two sort of limiting factors here. One is that the emissions reductions have to happen at these affected facilities. So it's not taking cars off the road. It's not dealing with non-electric systems. States have asked me about whether they can use those in their compliance. No. It still has to be tied back to those affected facilities and their emissions.

Then, two, because of the definition of the Best System of Emission Reduction, EPA was bounded by what has been adequately demonstrated. So they looked around the industry to see what kinds of activities are already being undertaken to reduce emissions from this electricity sector.

You then think about what Speaker 4 was pointing out, how little text there is in 111, how the 111(d) directive is even potentially more vague. There can be arguments about whether that gives the agency more or less latitude, but if you think about it, first of all, there's a consideration of other factors in 111(d).

EPA source categories, whether we combine gas and coal or not, are far more integrated than other source categories. To pretend that they each are their own island and that they are not always shifting utilization between them for various reasons would be to not realize where the source category is and how it operates.

You then layer on that some of the cases that I referred to and you see that EPA has set statewide budgets based on what's cost effective for folks to do even when the statute says it's about prohibiting particular sources from emitting and causing problems for downwind states. You see trading, you see these flexible approaches to the Clean Air Act. Does it get you all the way to where EPA landed on this proposal? I'm not sure. I don't think anybody is sure, but I think there are bounds to what they did, so that there is a rebuttal to your premise that this is sort of this unbounded exercise in taking over the electricity sector.

Question 3: Good morning everybody. The whole issue of the Best System of Emission Reductions, we're all fixated on system. And yes, listening to Speaker 3 and talking to folks in the industry, yes, everybody assumed that "best system" meant within the fence line originally, I think.

My first question is, once committing the sin, the unforgiveable sin, shall we say, of going beyond the fence line, if you've already committed the sin, well hell, go all the way--say "cap and trade." Let's dispense with all of this other stuff and all of the oblique references to regional cooperation and the rule and just go there, rather than having this really complex rule.

Then the second question I have comes back to the clarifying question, which has to do with energy requirements. I've had conversations with EPA where point blank EPA has told us that we have traditionally believed that to mean the energy requirements of the units, say, to run the parasitic load of running an FGD (flue gas desulphurization) or SCR (selective catalytic reduction), for example. But could "energy requirements" mean something different? Speaker 1, you seem to think that this is kind of everywhere in the statute or everywhere in the section. Could it mean reliability requirements? Or other sort of requirements, rather than just using it to justify energy efficiency?

Moderator: The first question here, as I understand it, is why didn't the administration put in place a national cap and trade system, and then open itself up to the criticism that "What you just are doing, Obama, is that you failed to get your cap and trade system through the Congress, so you're going to do it now in the regulatory fashion coming up to the midterm elections." Is that the question? [LAUGHTER]

Questioner: That's pretty much the question, because that's in fact what they're being accused of anyway. So if you're going to be accused of the sin, commit the sin.

Speaker 4: I guess a couple of quick responses. One, some states might do that, and the rule specifically talks about states maybe being able to use cap and trade, so they may do that at the state or regional level, or in this fictional universe where 50 states could work together, you can do a national plan that way.

But I think the better reason not to just do that directly is because, again, the Best System of Emission Reductions is about stringency, not about compliance options. A cap and trade system doesn't really tell you how stringent you can be.

EPA can look at these building blocks and figure out what's demonstrated and what can be done. But if you say that a cap and trade system is part of the best compliance system, OK, maybe it is, but you've still got to pick the cap. It doesn't tell you high it could be.

You could really have a tight cap and trade or a loose cap and trade, so putting that into BSER doesn't help you make the BSER decision, which is really about stringency.

Speaker 3: I think the answer is entirely political. I mean, the moderator caught it. The other thing is that when people accuse them of heading down this path, early on the White House said that no, no, we're not going to do a cap and trade. I think that, just as a practical matter, that limited them. I think they're hoping that many states do adopt cap and trade programs.

And some states will be in a very difficult position, right? Because if this rule does withstand scrutiny, then people who've been opposing it are going to say, "You know, the best way to do this is a cap and trade." Good luck getting states, at least some states, to agree to go along with something like that. But I do think the answer to your first question is entirely political.

Speaker 1: I think for that very same reason, and we started to earlier about enforcement--the fact that EPA did not talk about its federal implementation plan (FIP) if the states don't act. I think it's because the most practical way for EPA to move forward with a FIP would be with something that looked like cap and trade and just invite in states that default into that. Huge political ramifications if they put that out with the proposal.

Question 4: I want to ask the forest and trees question for a little different perspective. I think the economists of us in the room would all like to see a market-based cap and trade or price system, both because it's cheaper and because it also perhaps incents some technology improvements, because we really want global reductions, we don't just want reductions in the US.

It strikes me that by separating the question of stringency from the question of flexibility, EPA could do a relatively simply two step and get you there.

You could define stringency within the fence line, whether it's improvements in heat rates or gas conversions or some segment of units, taking into account age and energy requirements, and get to an equivalent national emission reduction, and then set a mass conversion formula that makes it just obvious that the cheapest way for everyone to comply is to do cap and trade.

If you separated things in that way it seems like you could get to cap and trade, you could avoid a lot of the sort of issues that are brought up by the second through fourth building blocks, and you would make compliance much easier, because you wouldn't actually have to quantify what the energy efficiency reduction was and how it related to the covered units.

It seems like an easy two step and I'm not sure. Maybe there's some reason I'm not getting why you don't go there, but it seems like something that should have been considered and perhaps is a viable alternative.

Speaker 4: I think that's a good idea, and at least in the level of detail that we've just talked about it, it doesn't necessarily conflict with the statute.

I think if you talk to a lot of, let's call them moderate critics of the rule, in other words, they have some problem with the way it's structured, in particular with the outside the fence line issue, but they don't oppose it in principle or think it's wholly illegal, I think that something like what you described is what they would like, particularly people in industry that say, “Look, we set the stringency and we can only think about these things. But, then when we go comply there's a bigger universe of things we can do.”

I think you get a critique then from the environmental groups that say, “No,” (I mentioned this briefly), “We're fine with flexibility, but we want you to think about that in the first stage when you set stringency. If you're going to make that pie bigger, we want our slice.”

Maybe you can do a kind of two step like you described and be a little more aggressive than you would otherwise be in defining stringency. There's some evidence EPA is doing this already. 6% in that first building block is pretty ambitious.

I think it's kind of a Trojan horse there that says, “Look, if you cut building blocks 2 and 3 and 4 out and you're only left with one, that's going to stay at 6% and that's really hard to do. So, you want those building blocks. Critics of the rule, you are going to have to comply with it so let's keep them there.”

But maybe they could push more in that direction. You have a narrow set of building blocks, but you are really aggressive about getting them. Although if you're too aggressive you open yourself up to this critique that's not “adequately demonstrated,” and you can't put it in the building block.

Comment: We've demonstrated coal to gas conversion a lot of places. That could get you stringency, depending on which units you applied it to.

Comment: The lead trading program in the Reagan administration was in fact a two step, so that that lead standard comes from one source, stringency, and then, purely through a regulatory move, the Reagan administration put in place what is pretty close to a textbook cap and trade system.

Moderator: That worked really well, as people know.

Question 5: Thanks very much. This is a really interesting discussion. I feel like I need to rise to the bait a little bit on the moderator’s social cost of carbon RIA question, but I will keep it brief because I know that's getting a little off track.

I just spent two years as a member of the Council of Economic Advisers, and I was, with my OMB counterpart, Howard Shelanski, in charge of the revision of the social cost of carbon (SCC) that came out about a year ago.

This is obviously something that we discussed in great detail. I'm going to give three points. First, in terms of the statement that every regulatory analysis since Jimmy Carter has been US only, that's just simply not correct. What I mean by that is that the SCC, with its global basis, has been used in at least 20 rule makings, most of which are finalized now. They are, of course, much smaller ones like efficiency of microwave ovens and so forth, but they were still official, they were rule makings with RIAs, and they seem to have been successful in terms of precedent setting.

I am not a lawyer. I do know that the attorneys at OMB and Cass Sunstein and so forth think that there is a legitimate basis for at least using discretion in recommending this as a guideline.

On a policy issue here I think I have the firmest of views, aside from just the facts of the history, which is that this really is, as of all people our moderator would stress, a global problem. If we think about the counter factual of, well, OK, so suppose it's $37 a ton, but we're 17% of emissions, so we're six bucks a ton, and then UK is $1 a ton, and then, I don't know, Norway is whatever, a few cents a ton, and so forth, that's one equilibrium. We could converge to that as an international equilibrium, and then we could ratify that in the context of Paris discussions, and so forth.

I think you would agree that that's the wrong equilibrium and that the way this works is a matter of putting forth what we think is the right equilibrium that other people will be able to follow, taking a position of leadership in terms of international climate negotiations. The power plant rule is part of that.

The SCC is part of that. There are many parts of the climate action plan that are part of that. And then you have global SCC as part of the international equilibrium is the one that we would want to strive for.

Specifically, however, on the rule, I would like to follow up on the earlier question, and I know you guys have discussed it, but I'm going to push a little bit harder, and now I'm going to slide into doing exactly what I suggested I should not, which is economists pretending to be lawyers.

I'm going to talk about three words in BSER and 111(d). One is the word "best," and it is the case that a cap and trade system is better than the best system that is suggested under the BSER, so it's hard to see how it's not a better BSER.

Second is "system." I think you have stressed, and many in this room would agree, that system, again I'm not a lawyer, but common sense says we're talking about the system of electricity production and that's a system-wide issue.

In terms of "adequately demonstrated," I would suggest that regional cap and trade systems or state level cap and trade systems have been adequately demonstrated in the United States, in which case I have a question for the lawyers as to whether there is a stronger legal standing for this than I understand there is for the quite questionable, increasingly questionable, legal standings of building blocks 2 and then 3 and then 4. So that's a question.

Then I'm just going to ask a really quick technical question, but it's one of great importance, which is about the legal issues associated with building a new natural gas combined cycle (NGCC) plant into a rate based implementation. And in particular, what is the deal that I just don't understand between the 111(b) and 111(d) and whether the new NGCC could be counted in? Is it a numerator or denominator issue? Or is it simply excluded in a rate-based 111(d)? I'd just love to have a little more discussion on the new NGCC.

Moderator: On the comment, I'll respond to that. You did a nice job of making the arguments that I frequently make on the other side, and I've written about, so I agree with all that. There's an additional argument, and that is the OMB guidelines which of course do not have legal force. The agencies don't have to follow the OMB guidelines. The OMB guidelines require the national but they allow the global in general. That's already there.

Questioner: In practice, if the agencies didn't follow the global calculation, they would have their rules sitting there for a long time.

Speaker 3: Others may have different answers, but I'm pretty sure we would all agree on the second question you mentioned. Section 111 says there are only two types of sources in the world. There are new sources and existing sources.

The only thing that can be regulated under Section 111(d) is existing sources. It has been argued, and I think EPA lawyers are struggling with this because it would make much more sense to include new natural gas in the denominator, but that's legally problematic, because those are clearly new sources that are covered by Section 111(b).

The definition tells you what a new source is, and then it says, "everything else is an existing source," so there's no middle ground. You're either a new or an existing source, and because it's a new source subject to a 111(b) standard, it can't then be covered by 111(d).

I predict that EPA will find a way to rationalize that. I think they are going to be convinced that they've already taken enough legal risk. We'll take one more to make this work. I think that's the issue. It's very hard legally to see how they could do that.

But let me come to your first, more important question. It's simply a mistake to talk about what a system is and what best means and all those other things. The question is the application of that system to what? Right?

For 40 years what that has meant is the application of the Best System of Emission Reduction to an individual plant. That's what EPA has done for 40 years, and that's what they did for new coal fired power plants, right? They didn't say the Best System of Emission Reduction was to allow new coal fired power plants to meet some standard by investing in renewables. Because you could conceive that the price of doing a new coal fired power plant is you also have to put in an equal number of renewable energy sources. But they didn't do that. They said the Best System of Emission Reduction is something that applies to the source, so it's not some theoretical thing. It's not, what is the best overall system for the country, for the state, for the world? It's, what is the best system that can be applied to this regulated plant?

Questioner: Doesn't that then go back to your comments about the NRDC plan, which is, suppose you do a state level cap and trade so you have the advantages of equating marginal costs? What does that imply at a plant level basis? And then the plant, how does it comply? It complies with this demonstrated procedure of buying credits.

Speaker 3: But you haven't solved the problem, right? A standard of performance is set based on the best system that can be applied to a plant, to a regulated facility. So it's very hard to see how the best system that can be applied to a plant is re-dispatch or energy efficiency.

Again, the statute says very clearly under 111(d) that what EPA can do is require states to establish standards of performance for any existing source, right? And you would say, so they're regulating any existing source. Any existing source doesn't have control over the dispatch of the electricity system. Any existing source doesn't necessarily have control over a statewide energy efficiency program. That's the problem. I think Speaker 2 mentioned it. The problem here is very simple to express. EPA is trying to pound a very big square peg into a relatively small hole, and it just won't work because of the way the statute is.

Again, we have 40 years of regulatory history as to what this means. EPA has talked a lot about what the application of a best system is.

I have to confess here that when I was at EPA we did try to interpret that to say a cap and trade program for mercury was a system that had been demonstrated, and I will say that we knew that that was a stretch, and we knew that we took a legal risk but, just like the Obama administration, we thought that that system was so superior we were willing to take that risk.

Now, the court never actually ruled on whether that was acceptable and it is amusing because David Doniger from NRDC, who will be here next week was vociferous in saying, "That's clearly illegal because it has to apply to every individual source." [LAUGHTER] So now we find ourselves in a kind of reversed positions.

Moderator: To be fair to David, since he's not here, or to that perspective, the concern also is that a cap and trade system and relocating emissions and therefore concentrating them, creating so-called hot spots, would be a concern with mercury that you didn't have to the same degree, certainly, with acid rain, that you did so much great work on, or with CO2. I think that would be fair to say.

Speaker 4: Just a real quick point on this new gas issue, this new source issue. As Speaker 3 clarified, you have new sources and you have existing sources, totally different. What the statute doesn't say is when a new source becomes an existing source. Traditionally, it's been every eight years. EPA is required in the statute every eight years to issue revised NSPS. It doesn't usually do so, but nevertheless that's in the statute. The traditional interpretation is that once the revision comes out, everybody that used to be new is now existing.

But that's just an interpretation. EPA could say, "You're a new source on day one and therefore have to follow the new source performance standards in order to be built. And then on day two you're existing."

You could in principle do that, and I think it would survive legal challenge. But EPA would actually have to do that, and that's an EPA decision. That's not something states can do.

Speaker 1: Really quickly I wanted to sort of challenge the premise that the standard absolutely has to be applied to each individual source. I can't vouch for the complete opposite, that it definitely can, by any stretch, but EPA has never interpreted 111(d) to so constrain it. While it has tended to do source by source standards, it has not exclusively done that. For instance, there's a NOx trading program for combustors. It has never been ruled on by any court, so this is an open question.

And there are textual reasons why one might think there would be more flexibility in 111(d) than other programs. For instance, it's the parallel to "standard of performance" for the program that regulates hazardous air pollutants. The maximum achievable control technology tracks very similarly the language of the definition of standard of performance, except that in it, it says that it has to be the best system as applicable to each source. That language is not in 111(d) or in the definition of standard of performance. So while the word "source" is in 111(d) and will be an obstacle and will be something litigated, it is not an open and shut case that each standard must apply specifically to each individual source.

As far as the "best system," and that that should be a cap and trade system, I think Speaker 4 addressed that earlier, where that explained the compliance technique. You still have to figure out how to measure the stringency.

What EPA might do is say, "Let's look at a trading system. How have they operated in the past? They've shifted utilization. They've had credits in renewable energy and energy efficiency. We'll use those to set the stringency." Whether that's defensible I don't know, but that's what I think they're doing.

Question 6: Great panel. I now know why I'm not as a smart as a lawyer.

Whenever I'm confused by the present, I either retreat to the past or the future and worry about things that I don't have to deal with right now.

A few years ago we as a sector had sort of grudgingly gone along with this idea of an 80% target by 2050, which under an economy-wide cap would have meant we were decarbonized by 2040 or 2045 almost completely.

I keep that in mind, and I keep in mind the external pressure and the 300,000 people who supposedly marched in New York City, so I don't presume that this problem goes away any time soon, or that whatever survives court challenges is what we live with ultimately. This thing probably keeps tightening over time. I'm looking at the fact that it looks as though the incentive is to build new combined cycle turbines, but those may become existing at some point, and in eight years or 10 years or whatever it is, I am faced with another set of requirements and maybe regret the decisions I made today in investment.

Looking at those problems, I'm wondering, has the EPA walked themselves into a blind alley with this sort of construct, in terms of justification for further tightening? So, that's one.

The second question is, since I have people who I probably could never afford to pay individually for opinions, what would be your advice to me [LAUGHTER] in terms of either a strategy for how to position myself or how to move forward and help this evolve in a way that positions me so that I don't regret in 10 years what I might do tomorrow?

Speaker 1: On the first point, whether it's walked itself into a blind alley, I think what the agency was attempting to do was to avoid that. It talks about the four building blocks as being adequately demonstrated techniques right now in the industry for reducing carbon emissions, but it certainly didn't hold states or sources to just those compliance methods. It talked about fuel switching. It talked about combined heat and power. It talked about transmission upgrades, which came up yesterday, CCS, and a whole host of other technologies and approaches. This is funny in the context we're talking about how wildly aggressive EPA was, but it felt it was being conservative by sticking to these four techniques.

I think by talking about those other techniques and saying that they are out there on the horizon, they could become a rationale for coming back and ratcheting down the standard.

There is also an open legal question about whether EPA has to go back and ratchet down existing source standards, which I won't bore you with.

EPA has ratcheted down 111(d) standards before, but it's only been for incinerators, and they're also subject to another rule. They are attempting to keep this flexible.

I hear you on your point of needing to plan ahead years and decades and whether something could change here. I can't speak to that.

Speaker 3: Can I make a quick comment? I was at another event with lots of very senior people from the administration. Off the record discussion. People on the Hill. Some very thoughtful people.

Someone turned to me and said, “We all know that there needs to be a program and we all know that the most effective way is to somehow put a price on carbon either through a tax or through an allowance rating system.” They said, “So when are your clients going to sit down and get serious about that?” I won't give you my whole answer, but I do think we were actually much closer than people realized in the Waxman-Markey days. It was a couple of changes that I think would have led that to pass.

But my response was that I think to have that conversation, what the industry needs is certainty that that's the program that will be used to reduce greenhouse gas emissions. It's not going to be the Clean Air Act. It's not going to be the National Environmental Policy Act. And a very senior person in the environmental community turned to me and said, “We will never give up the Clean Air Act,” and I was surprised.

So even if you had a carbon tax. Even if you have to have cap and trade, this very senior person said they would never give that up. There were other people in the environment community who said the same thing.

I said that it doesn't work very well for carbon. She said, “We know. We've gotten these dramatic reductions in lead, we've gotten these dramatic reductions in SO2 and NOx.”

What I took from that is at this point there's really no interest in coming back to the table and thinking about a more sensible approach. Now, the problem is that if this rule is struck down, then the leverage changes, right?

The threat of the Clean Air Act brought people to the table. If they know that the Clean Air Act can't be used in these terms…but I think ultimately there will be a legislative solution that will be more sensitive than this one.

I see someone shaking his head vigorously, but the reason I think that is there are a lot of people who are opposed to any CO2 control. But that's not the industry as a whole. The industry would like certainty. If you believe, as is typically the case, that they have the ability to influence their elected representatives, be they Democrats or Republicans, I think there is the ability to come up with some sort of a scheme.

Comment: I'm sorry. I just feel like I have to respond to that. If you go back to the President's inaugural address, if you go back to his first State of the Union address in this current administration, where he set in stage for the climate action plan and going forward with these rules, he was clear. He said, “My first choice is to work with Congress to have a market-based solution to climate change. We encourage them to do that and we will work with them. But if they don't, then we will use the authority of the Clean Air Act.” It's not as though we're going to do both of these things. I would really strongly disagree with your reading.

I am sure that there are some members of the environmental community who would like to have both. I am sure that there are more members who will use as a negotiating position that they would like to have both, but I would disagree with your reading quite strongly that there's not room for middle ground.

And I really would disagree with your reading that the moderate green community is the source of the problem. I don't think that's correct.

Speaker 3: I think I'm not allowed to talk about who was in that room, but there were many members of the moderate green community that were in that room who said…now, you may be right, that it was a negotiating ploy.

I want to make one more point that you may disagree with, but I was involved in the 1990 Clean Air Act amendments, and that process was very different because the White House came up with its proposal. They came up and then they did the thing that administrations do. They twist arms. They put pressure on their own constituency. They cut deals. They were out there with a program that they wanted to have passed through Congress. That hasn't happened in this administration.

I agree that the President would prefer to have a market-based solution. But to my mind there was never a serious effort to do the things that would have accomplished that. Again, I go back to the 1990 amendments. I think that's the only way it works. For something this controversial, this big, you have to have White House leadership. Not just saying, "We want it," but actually coming up with a plan that they're willing to commit to and go out and try for, something that gets people from both sides.

I think that will ultimately have to happen, and I think it will, but I think right now, at least in my experience, that requires compromises, and the moderate greens are, right now…why would you compromise if EPA has this dramatic authority under the Clean Air Act and they can ratchet it down every eight years? I mean, that's a pretty good hook.

Moderator: It's also true that the 1990 Clean Air Act amendments received, like, 85% of Republicans, and I think it was 94% of Democrats who voted in the House. Waxman-Markey received a similar percentage of Democrats and I think it's something like 3% of Republicans. Political times have changed tremendously since then.

Speaker 3: I agree with that.

Speaker 2: I just want to add a comment to kind of bring us back from the politics to maybe try to address your question about strategy, because it probably won't follow the schedule of this proposed rule, but there is no doubt in my mind we're heading in this direction, and I think everybody on this panel agrees that greenhouse gas regulation is coming, and it's just a matter of stringency and timeframe.

We've been working with executive teams across the industry, especially utilities and some planning authorities, to look at what the future holds. Because once again the industry is faced with making large capital investment decisions under significant uncertainty.

What's amazing is we work with the executives to look at future scenarios, what the world will look like, and then at the end it's like "Oh, my gosh," (even in the most conservative utility), "We need to diversify our portfolio. And we need to absolutely look at our greenhouse gas emissions."

It's a risk, whether we litigate it or not. It's a risk for the companies. The building block is no surprise at all from an industry perspective, because those are the ways to diversify our portfolio. Using natural gas, at least for the interim next 20, 30 years, to diversify the existing resources, and then lots more renewable, and there's no doubt that the prices of a lot of these resources have been coming down, and will continue to come down, and energy efficiency.

I think these building blocks are no surprise. So I do encourage all the executives in the room to think about your own strategy going forward that way.

***Question** 7*: I've got hopefully what are quick hitter questions mostly on the legal side. First is addressing block number one. I don't want to say block 1 is offensive, but if I had 6% efficiency and I hadn't found it yet my commission would have, but assuming there is an efficiency of 6% in a coal- or gas-fired plant, when or does NSR (New Source Review) get triggered?

My second question is about going from a new source to an existing source. Eventually a new source becomes an existing source. When does that happen? That's important to me because in the state of Arizona our target is 735, that's our interim goal, and our final goal is 702. So our interim goal is really 702.

I have five years to get from 1500 to 702. If I put in a bunch of new power plants, I don't want to talk about what that does to rates. I can't even talk about power flows. But if I do that, when does that thing become an existing system, so I am now of compliance for that particular asset?

My third question is about the Native American communities. You talk state by state. I have a community within my state that is going to get a different number than I get. What gives EPA the authority to do that, when I don't know of any other rule in which they've separated the Navajo Nation in my particular state out? If they truly are a sovereign nation, why do they have to do this anyway?

Finally, regarding an interim goal, I haven't seen that before. So if you could tie in that interim goal argument--is that something legally persuasive?

Then, finally, I'd argue that this is an IRP (Integrated resource Plan). The history in Arizona of the IRP is as follows. First, in the 1990s we put in a bunch of merchant generation plants, because that was the federal policy. We were going to competition. We were going to have all these merchant plants, and we were going to ship California all this surplus energy.

That didn't turn out. So the sin of following that policy now gets added in my goal. And my goal is now artificially low, I would argue, at 700.

The second thing is the Navajo generation plant up in the Grand Canyon, which is a coal-fired plant, and it was the environmental and federal government's solution because they didn't want to dam up the Colorado anymore. It was built at the behest of the federal government, it was a 21% owner of that plant. (Something around 20%). We have a coal-fired plant that now is subject to this rule.

Finally, the Fuel Use Act of 1978, I have a natural gas-fired plant built in the '60s in Tucson that they made me convert to coal. For following that rule, I am not only subject to this rule, but I also got regional haze.

Get this. A plant that I built in the '60s (I didn't personally build it, but my company did) and converted to coal in the '80s is now subject to regional haze, which is supposed to apply between the years '68 and '72-ish.

My point is this. On all of this, in my opinion the EPA is 0 for 3 in Arizona, right? What gives me hope that they're going to be 1 for 4 on this? Seriously, what is the authority for the EPA to do all of those things, but specifically resource plan, because that's what's happening in my state? And the cost, I would also argue, is not just simply the generation switches, it's the power flows. It's the supply. We have no source of gas in Arizona. We have no storage. If you're calculating these costs you've got to calculate a lot more than just simply generation costs.

Speaker 1: All points well taken. On block 1, that is a big question, right? And I think there will be a legal challenge to block 1 and the feasibility of 6% efficiency upgrades. This is actually an issue in an enforcement case right now against Ameren. Ameren's asked for in discovery for all the information that EPA used to justify that 6%.

The argument being what you said. In many cases the reason EPA knows that that order of magnitude of efficiency upgrades is possible is because it's already happened. So once it's already happened at some of those coal plants, is there anything more to get?

EPA's point in setting the building blocks is that by setting a target, say, of 6%, that does not mean that each state is supposed to achieve at 6% efficiency improvement at its power plants. In fact, a state can choose to comply with any mix of the building blocks. But this is definitely an issue that EPA has been asking for comment on.

Questioner: Does it trigger NSR (new source review)?

Speaker 1: They issued, at the same time, a proposal on modifications. I'm not thinking, off the top of my head, what the answer is...

Questioner: We collected a list of NSR claims, enforcement claims brought against utilities for energy efficiency projects. That's why Ameren is looking at this.

They're saying, "EPA has this rule. They want us to do these things. And when we do them, you come after us and say we've violated NSR."

Now, EPA would say, "We want you to do these things and go through NSR," right? I mean that would be the legal thing--we want you to do these energy efficiency improvements but you've got to go through NSR to do them. That again calls into question the timing of all of this.

Speaker 1: One of the rationales EPA has for the building blocks, though, is to try to avoid this, right? Because NSR applies when you make a change. So, EPA says, "If you only had block 1, you'd be making these old coal plants a lot more efficient. You'd run them more, you would trigger NSR." If you do it in conjunction with some of these other techniques, and you're reducing utilization and shifting over to gas, maybe that means taking permit limits and that would be a way of avoiding NSR. But certainly it's an issue out there.

As far as when a new source would become an existing source? That usually turns on a date that's set in the rule, and not the age of the plant. So it would be forever a new source if it came online after a certain date, which I think is proposal of the existing rule.

You had a lot of good points in here about the various things like tribal carve outs and interim goals. I don't know that I can speak to that. You are correct in characterizing this as somewhat like an IRP. I think that's why the target is out so far. I think EPA set an interim target just because the end date, the actual enforceable target here, is so far away.

But I think it is because there is an attempt here to piggyback on the IRP process and on the PUC processes, so that you can be making long-term plans to get to this diversification and carbon intensity reduction.

Speaker 3: Can I just add two quick things? EPA is going to change the interim approach because even many of EPA's allies, people who support this, have said that's just not feasible.

So, EPA is, I think, struggling right now to figure out how to ensure that there's a glide path without having this, because I think most people think the 2030 goal is achievable, probably, in every state. It may not be fair, but it's achievable. So I do think they will change that.

Speaker 4 said something earlier that I meant to respond to, and he'll respond to this. He said that the industry will be nervous, because if these other three building blocks go away then they have to do this very expensive 6% improvement.

There is no way that that would be considered an allowable performance standard for this very reason, which is that EPA didn't do the kind of technical work that it always does to support a standard of performance. And they consider the fact that there are many plants out there that have already adopted all of these operational and other hardware changes to become more efficient.

I also happen to know that the study that EPA relied upon to do that, the authors of that study are submitting comments saying, "You've completely misused this study."

We've actually looked at what can be done at a number of power plants and the most that we think can be accomplished and most plants there's 1% to 2% and that degrades over time. It's not a onetime thing that you upgrade your plant and then it continues.

So that building block, I think, will change in the final rule. And EPA has not done the kind of work that would make that a legally defensible standard of performance. I think they could do a legally defensible standard of performance, but I don't think that 6% is even close.

Speaker 4: Just a couple quick things. First of all, I won't stick up for 6% or EPA's work there. I'll wait and see what they do in the final rule, or in the event the other building blocks get cut out, and we'll cross that bridge when we get there.

A couple of quick points. You made a great point that it's nice to say you can diversify if you don't know what the future is going to hold, but that only works if you're big. If you're small, if you're a co-op, if you're a muni, you can't do that.

Traditionally, in a situation like that, we say, "Buy insurance." I don't know if anybody's selling climate policy insurance. Maybe that's a business line for somebody. [LAUGHTER] You can. You can buy climate policy insurance.

OK, so if you're a small utility, go buy climate policy insurance. I doubt it's a very thick market, but hopefully you can get a good rate.

Existing sources? I mentioned that briefly. We don't know in the rule how they're going to be treated. My reading of the rule today is that if you build a new gas plant and displace a coal plant, that coal rate comes out of your state's calculation, but the new gas doesn't go back in. So it looks kind of free.

That even leads to that perverse situation that Speaker 2 described, where you can replace an existing gas plant with an identical existing gas plant and get a benefit for that, and that's obviously crazy, so EPA is going to have to do something about that.

That something, I think, needs to be a definition of when a new source becomes an existing source, and it's got to be something less than eight years. The EPA hasn't said what they're going to do there. They've given no guidance at all. They want to kick it to the states. That's not a decision states can make, so EPA will have to do something there.

Speaker 3: But they've never commented on that.

Speaker 4: No, not that I know.

Speaker 3: Nobody knows when a new source becomes an existing source, because it's never happened before. 111(d)'s been used five times, and in none of those cases does anybody address the issue of when a new source becomes an existing source. So that's just another complete unknown.

Question 8: I have a really quick technical follow-up on this issue of new gas plants versus existing gas plants. Just ignoring the legal issues, is there any sort of economic rationale for treating them differently?

Speaker 2: No. [LAUGHTER]

Question 9: I'd like to ask about the prospects for mass based programs, and for cooperative compliance plans from multiple states, and how that might relate to existing cap and trade plans, like AB 32 or RGGI.

Speaker 4: Just one quick point on AB32. There's some linking going on already with Québec. Québec's irrelevant for purposes of the Clean Power Plan, unless there are political developments I haven't heard about.

AB32's a problem here is for two reasons. One is that it's economy-wide. It doesn't just focus on the power sector like RGGI does. I know less about RGGI, so I won't say anything about that.

The other one is that AB32 allows offsets. It's not a well-developed program yet, and it's also linked with Québec, so you can view that as a kind of offset from where you're sitting in California.

If there's a compliance option that EPA says you can't use in this rule, it offsets. You need to have reductions that come from the regulated source. Things like, if you build a renewable plant, if you increase efficiency, yes, your emissions at your coal plant will go down.

That's not true for something like pulling cars off the road. It's not true for pulling things out of the air by planting trees, or anything else that your offsets would include.

To the extent that AB32 does those things, it doesn't seem to me like those reductions can count under EPA's programs. It's going to be a lot of work they'll have to do to work those together. If that can be done simply, yes, maybe you get people joining them.

Moderator: I agree with what Speaker 4 just said. There are those problems, and there are additional problems I won't take time to talk about with AB32 becoming part of compliance with this rule.

That said, to answer your question, if I had to make a prediction, it would be the following. If this survives legal challenge it's going to be California, Oregon, and Washington--either a multistate plan or linkage among them, and Pennsylvania will join RGGI, which would be very significant. Does someone else want to comment?

Speaker 1: Short of joining a full-fledged trading program (and there is a very valid argument that the timeline doesn't allow that for those that are not currently in a program), there are other interstate ways of linking. There has been talk about creating interstate just renewable energy or energy efficiency tradable credits so that you could deal with the interstate problems of accounting for where the reductions occur when you do either of those activities.

Speaker 2: Just one more thing. Cap and trade is great and we all agree that's an efficient way, but also realize that there has been a lot of price volatility associated with cap and trade experiences in Europe. And the fact that New England states did not have price volatility has almost nothing to do with the way it's set up, except that we over-complied due to economic reasons.

Moderator: We should take note of the fact that AB32 cap and trade system has a price collar in place to limit that price volatility.

Question 10: This is question for the lawyers on the panel, and that is, what is your best estimate of what a FIP would look like?

Speaker 4: I'll just say one thing. I don't know what it looks like, but it's tempting to sit around thinking about, how flexible can a FIP be? Like, if I'm the czar at EPA and I'm FIP-ing a lot of states, I want to make it as flexible and efficient as possible. But I don't' think that's the right outlook. I think they don't want to make it as good as possible. They want to make it as bad as possible so that a state would have a better incentive to do it themselves. How bad is bad?

I think you've got to start with a stringent block 1 that's going to be imposed on the state, but beyond that I haven't thought about it very much.

Speaker 3: I have thought about it quite a bit, actually. The first point is this. If you look at the history of federal implementation plans and you look at the date that a state failed to submit an adequate state plan, and then how long it took to get it to a federal plan, it's a minimum of seven or eight years. That's when there's only a handful of plans and they're relatively simple.

It would be an enormous challenge for EPA to do one or two plans, much less a large number. It’s resource intensive. You have to engage with the stakeholders. You have to come up with a proposal. You put it out for comment. So it's going to take a long time.

That really is the only enforcement mechanism here, right? This is different from the new source proposal where EPA said, “OK, if you don't want to regulate greenhouse gases, no new plants in your state.” And they could enforce that.

There's nothing that's enforceable against any company until there's a plan in place. Either a state plan or a federal plan. We're years away from having a federal plan in place.

I think that the only way that EPA can do a federal plan that achieves something like these goals is something like that NRDC approach, where they translate the state requirements into an emission rate that applies to each individual source. It will be something that cannot be achieved at that source, but you can get credit for investing in renewable energy and other things.

As I envision it, that's really the only thing I can see EPA doing, but here's another point about that. In the unlikely event that this actually gets upheld, that doesn't tell you anything about the legality of the individual state plans. Let's say the EPA does a FIP for Texas. That's challengeable, not in the DC Circuit, that's challengeable in the Fifth Circuit, which typically takes a somewhat different view. There's a chance that the Fifth Circuit may say, “Well, EPA's overall program might be legally defensible but this certainly isn't.”

The last point I always make is this is a great thing for lawyers in private practice. [LAUGHTER] Because there are litigation opportunities to challenge this rule and that rule and then the individual state plans.

I'm figuring that I can support my kids and retire fairly soon on this, and I think ultimately we're going to come down to let's have something that gives everybody some certainty. But the whole federal plan is a question, and EPA hasn't figured out yet what it would do.

Speaker 1: It is absolutely the case that there's going to be litigation on this rule, both in the DC Circuit and Supreme Court. When we keep saying we don't think this will be upheld, I think we all agree this won't be upheld because this proposal is amorphous at this point and has multiple options and rationales for the options. I think where we disagree, probably, is about whether a final rule can come together that would be upheld. There is certainly also going to be the FIP-type litigation in each of the circuit courts.

That doesn't speak to the relative strength or weakness of EPA's approach here, right? This is just what people do now. You do not finalize a Clean Air Act rule without it being challenged and going to the Supreme Court. This is just sort of business as usual.

But actually, I generally agree with Speaker 3 on what a FIP would look like. I think EPA does not want to get into the business of regulating PUC programs. I mean folks there have told me that.

So, it would probably be a rate that's allocated to each of the EGUs. The EGUs would be responsible for achieving that rate, either inside the fence line or through a trading program.

Comment: The problem with the EPA saying they don't want to get into the business of regulating the energy markets, for example, is that one of the concerns that has been expressed is that once you file a SIP, then you've opened the door for EPA to begin to actually to do what they don't want to do, as well as, even more troubling, you have private litigants or groups out there that would then avail themselves of the courts to try to do things that --

Moderator: Do you want to comment very briefly?

Speaker 1: Very briefly, this is a whole other fascinating topic that we didn't even get into, which is the various enforcement strategies.

EPA added as sort of a backup this state commitment idea, and I think it was exactly to address this. There are a lot of states concerned about making their PUC programs federally enforceable and open to litigation by environmental litigants.

This state commitment approach that's sort of floating out there that EPA has been asking for input on would have the states stand in and say, "We commit to achieving X reductions or reducing the overall rate through these programs, which we will remain as state enforceable programs," and sort of keep them beyond that federal enforceability.

Question 11: Are there ways in which EPA could have gone about this a little differently, where it could have been less likely to be legally challenged?

In particular, one question I've never quite understood is why the focus on rate-based reductions rather than mass-based?
Speaker 3: I'll give a quick answer. There is absolutely nothing that EPA could have done to make this less likely to be challenged legally. [LAUGHTER]

I do think, in a funny way, that the NRDC approach was more legally defensible than the EPA approach, because that actually focuses on the regulation of the individual plants as opposed to setting something that applies to the state.

EPA has a really hard time doing that here, because it's all about, this is the best system that can be applied to these regulated plants. Their own regulations say wherever possible that should be an allowable emissions rate and they explain why that is.

Trying to impose a mass cap, I think, creates much more legal vulnerability. It doesn't mean they couldn't try, but I think it makes it even less likely that it would be upheld.

Question 12: Thank you. I just want to distill this down, because I'm from a state where climate change is a very pressing issue.

We've got problems with our snow pack. We've got problems with our shellfish industry. We've got problems with pine beetles living longer because of longer summers.

Congress hasn't acted. EPA steps in. The way I see it is if they were going to use the tools that we all agree they have, they would do something inside the fence. But there are policy reasons and there are liability reasons that you wouldn't want to do that.

That's the poison pill. So, here we are. We're arguing about the legality of all the flexibility they're giving states, but isn't that an alternative to the poison pill?

Really, wouldn't it make more sense for us to not look a gift horse in the mouth, thank EPA for the flexibility, roll up our sleeves, and get to work, rather than going through this kind of discussion? I'd just like your thoughts on that. Isn't that really what we have here?

Speaker 3: I don't mean to do all the talking but I'm very opinionated about this.

You're assuming that if EPA only did something inside the fence line, the stringency would be the same. It could not be the same.

That's the problem, because to follow the traditional approach, EPA would effectively have to go out, look at all these different types of plants, look at the best heat rates that people had approved, and then say, "Here's the heat rate that you have to reach for your plant, based on the Best System of Emission Reduction," which would be limited to operational issues and potentially changing out turbines.

But the stringency would be based on the best system that could be applied to that plant. The only way to get around that is what NRDC did, which is to say, "We're going to go beyond what can actually be achieved. We're going to set an emission rate, but we're going to allow you to achieve that rate by doing all these other things," and maybe EPA will ultimately come around to that.

In terms of the traditional way of doing it, it just doesn't get you very much in terms of emission reductions, and that's why EPA has been pushed to do something that is legally questionable.

Speaker 4: Just quickly, even if you didn't care about separation of powers and rule of law, and you just wanted the best outcome possible, it doesn't matter what you want and I want and everybody else in this room wants. All you need is one litigant to get standing and challenge that issue, and if it's illegal, it's illegal.

Question 13: The question I have is, is it really possible to comply with the rule without cap and trade? I ask that because without cap and trade, building blocks 3 and 4 will be less effective, because as your renewables grow and as your energy efficiency gains grow, they will more likely displace gas production and coal production in and of themselves without a cap and trade system.

With a cap and trade system, both 3 and 4 will be more effective, because you can set the price of carbon high enough to make sure that gas comes ahead of coal in the merit order.

The other problem I have is with building blocks 1 and 2. For building block 1 I can see where you could use a command and control requirement. Simply have an emissions standard for coal plants. But I don't see how you can implement building block 2 without cap and trade. Maybe there's some problem with my logic here, but isn't cap and trade really almost necessary to make this work?

Speaker 2: Certainly, for some states I think that's at the heart of the issue, too. Some states don't need anything, really, and they will be able to comply. And some states will be find it very, very difficult to comply.

But I think it can still be accomplished. I think all the most stringent goals can be met, putting aside reliability issues. I think it's physically possible, but probably not plausible without some kind of collaboration or trading mechanism or market-based approach to reduce emissions.

Speaker 3: Again, you guys work on lots of issues. This is all I work on, so we've spent a lot of time thinking about this. The only sensible way to do it is to have a carbon price or an allowance price. You kind of play around with that to get to where you want to go.

And EPA said, "No, you don't have to do that." And I think there are potential ways that would involve maybe a shadow carbon price and you would agree that in a certain ISO or a certain RTO you wouldn't actually charge that price, but you would require bids into the system to include a shadow carbon price.

I suspect that for states that don't want to have a cap and trade or a carbon tax, then you'll see something like that. It's hard to see how else you could do it in competitive markets without running afoul of FERC. I mean, there's market manipulation issues and which units you're withholding at certain times, so I would guess that you would see something like that.

Speaker 2: By the way, the other important aspect of this, of course, is cost to consumers. One of the proposals that uses prices, carbon pricing, to reduce emissions, is to collect the carbon revenues and give it back to rate payers to mitigate some of the effect of carbon pricing.

So it's not a tax, but it does place a price on carbon and then distribute it back to rate payers to mitigate the costs. So, that's just another approach that's not cap and trade.

Comment: The bottom line is that there needs to be a price on carbon, whether it's imposed in reality or it's imposed as a shadow price. That's what I'm hearing.

Speaker 2: If you want a market-based approach and you want to reduce carbon emissions, which I think that's the goal, then you need some kind of price on carbon.

Speaker 3: In regulated states, there are ways in theory that you could change the dispatch to get to 70%.

Speaker 2: But that would be to have a shadow price.

Speaker 3: No, you could do it in other ways, but it's just very, very tricky and so I think it really does force people in that direction.

Moderator: One way or another, we're going to have shadow pricing of carbon through the ISOs, or we're going to have a carbon tax or a cap and trade system if this goes forward.

Speaker 3: One more thing on the consumer impact, right? The EPA says this is going to save everybody money, right? You have to spend 8% less on your power bills in 2030, so you don't need to worry the impact on consumers.