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Rapporteur's Summary*

Session One. More Renewables, Less Carbon: How Fast, How Far, and at What Cost?

In proposing plans for carbon reduction, policy makers and advocates envision, or mandate, a heavy reliance on deploying renewable energy. In the beginning, it was clear that the system could accommodate expanded renewables without much cost beyond the direct subsidies. Early studies showed few immediate limits or unintended consequences. Now, the accumulating experience with increasing penetration of renewables, and accelerating plans for more, continue to bring pesky questions to the forefront. There is a wide public perception that more renewables means less carbon, almost without limit. At the same time, there is an active public policy debate that implies the absence of a free lunch. While wind and solar emit no pollutants, what more have we learned about the constraints on the role in carbon reduction that some envision? Does intermittency or location result in secondary effects that dilute their ability to address the larger problem of reducing carbon emission? What new market products, market designs or technology will be needed or available to facilitate progress? If so, how does that play out? And at what cost? What are the critical assumptions and, what policy choices are needed, to meet our ambitious goals for reduced carbon emissions?

Moderator.

Thank you very much, Ashley. And good morning everyone. I'm really happy to be here. As always, it looks like there's a great agenda. And the first topic, where we have the panel of luminaries assembled to my left, relates to the nation's path toward installing more renewables and using them for electricity. How fast can we go? How far can we go? And at what cost? And what are the things we need to work through to get there? Obviously, this esteemed group knows the nation's going through a tremendous growth in renewable energy, both central station and distributed. It's powered by a number of factors,

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of course: federal tax policy; state policy; renewable portfolio standards in 29 states and goals in eight others; greenhouse gas targets in almost half the states; customer choice, with more and more companies taking a pledge to use renewables, including very large customers; and, of course, the pace of technological development. The growth in renewables is complemented by the growth in affordable domestic natural gas, which can, depending on the technology, play very well with renewables, and the growth in electric storage. And it's all to the benefit of customers, with improved health, environmental benefits, and lower costs once they are installed, because of their very low-cost characteristics.

But, of course, there are several very significant differences between renewable resources and the traditional fuel-based generation around which our grid was built and our markets were planned. As compared to traditional fuel-based generation, renewables have different operating characteristics. You don't just turn them on when you need them and turn them off when you don't need them. They need to be balanced, because they're dependent on the source, which can lead to the need for fast-ramping resources when the sun goes down or the wind stops blowing, and those fast-ramping resources can't always be paid on volume if they're been sitting around through the peak doing nothing.

So, it's really changing the way we think about resources. It's almost unnecessary for anyone to mention the duck curve anymore. What I notice is that, as I go around the country, other states are finding new animals--we have an armadillo curve, a loon curve, and so forth. But they all represent the same thing, which is a lot of power on peak, depending on how fat the animal is. And someone even told me there's like a "pregnant duck," and I tried to explain that ducks don't get pregnant, but then we just went downhill. [LAUGHTER]

In addition to different operating characteristics, renewables have different cost shapes. We had taken it for granted that you pay for energy on volume because the major cost component is the fuel you're burning, but with renewables, the cost's up front, and then there's virtually almost no marginal cost going forward. So that means that the whole way we attract investment and they get paid in the markets is different, and that's leading to a trend of paying more for services--ramping and scarcity and various ancillary services--as opposed to just paying for energy, which is where most of the money came from. And, of course, there's different geographic characteristics, particularly for central station renewables, which have the best capacity factors and the best locations. And that means you need transmission, unless we're going to move all the people to where the best wind is, which is unlikely. We need transmission to bring the best wind to where the people live. And that's straining our ability to plan and pay for it and decide on it.

They are building a lot of transmission in New York. Even within one state, that on the map of the United States looks pretty small, getting transmission from western New York, where the wind and the hydro is, to where the people live is like a 30-year effort, which has really taken off now. So, when you think about getting transmission from North Dakota to Chicago…just ask Clean Line.

And the final challenge to mention is that, since so much of the renewable targets are being established state by state (something that's been discussed many, many times at this forum) and the markets are regional in scope, you have different states with different targets within regional markets, and the markets are struggling to figure out how to adapt.

So, how do we deal with all this? I just get to ask the questions. How do we deal with the changes to the markets precipitated by increases in renewable energy? What does this mean regarding the ability of renewables to help us reach ambitious carbon goals? And what new market designs, technologies, and products should we be looking at to help us get there? Fortunately, we have a panel of luminaries to my left. So, we'll start with Speaker 1.

Speaker 1.
Thanks, Ashley and Bill, for inviting me. I think this is a very interesting topic. I like going in the end, but I'm going first. It's great to be the cleanup hitter. Instead, I'm going to sort of set a big-picture stage. In general, I think these panels are really boring if everybody agrees and says the same thing. So, I'm definitely, I think, not going to say the same thing as everybody else. And I'm also going to be, very deliberately, somewhat controversial and caricature-like in my remarks. I'm going to focus a lot on big-picture kind of end-state things, and I do not want to diminish the importance of the stuff that happens in between, in what is called the transition, which I would think the rest of the panelists might be concentrating on more.

So, with that being said, what does "less carbon" mean? That's the starting point. So, this is an oldish picture of the US greenhouse gas inventory, through 2014 only. If (and there's obviously an "if" here), if we sort of take the Paris Agreement mandates/goals as a given, then my first observation is, the emissions reductions that are hard are in sectors like industry and agriculture. And, at least in 2014, the emissions from those two sectors alone exceed the emissions that the whole US economy can have by 2050. So, we can hope to reduce emissions in agriculture by all becoming vegetarians, or to reduce emissions in industry. But, assuming that's going to be really hard, that means, basically, that achieving the Paris goals means completely carbon-free everything else, in particular, the energy sector would need to be completely carbon free by 2050. So, that means decarbonizing primarily three big sectors: transportation, buildings and electric power.

Second point. How to do that is pretty unclear, but electrifying a bunch of stuff is at least a pathway that we know about. And, you know, it's pretty dynamic, in terms of the new technology that's come around. So, I think it's a pretty safe bet that a fair amount of electrification will occur. For electric vehicles, electrification of passenger vehicles for sure, but for medium and heavy-duty vehicles, it's less clear. For planes, it's even less clear. But there is investment into these kinds of things.

So, what that means is, less carbon in 2050 means, likely, a significantly larger role for the electricity sector, and if the energy sector is carbon free, then the electricity sector certainly is carbon free. So, that means having a completely carbon-free electricity sector by 2050.

Alright, so how effective, then, are renewables in reducing CO_2 emissions down to zero? Well, one question I would ask is, “Well, what else are we going to use, instead of renewables, to get zero greenhouse gas emission electricity production?” There are a couple of conventional resources that could do that. Nuclear is one. Eventually, the existing nuclear fleet is probably going to reach the end of its useful life. So, are we going to build new nuclear plants at a cost that’s lower than building renewables? The early evidence is pretty bad, I think. There are, obviously, efforts to build the next generation of nuclear generators, small modular reactors. I’m not sure whether they are always ten or 20 years away, but it’s a possibility. The second possibility is obviously fossil generation plus carbon capture and sequestration. The same question applies. I mean, is that going to be cheaper?

My sense is, compared to those two options at least, the classic renewables: wind, solar (both PV and in some parts of the country maybe concentrated solar), plus batteries, already seem pretty cheap today. And that means that with the remaining “subsidies” (whether that’s just called a subsidy or sort of a proxy for pricing carbon doesn’t really matter)…but with those subsidies in place, there are already many part of the US where renewables beat existing fossil generation, and certainly new fossil generation, so the procurements now occur in the two to three cents per kilowatt hour range, as I said, with some remaining subsidies, so if you take those subsidies out, you have four to five cents a kilowatt hour for the best location renewable resources. I am not aware of any other fossil generation, certainly not with CCS, that you could build from scratch at that cost. And these technologies are still relatively immature, relative to, say, a combustion turbine. And they are technologically different, in the case of solar, for example, or batteries, such that you would think that the cost declines going forward may still be pretty substantial. So, if renewables are close to being at par with existing fossil generation today, I would think that that balance is going to continue to shift.

Now, you know, a lot of the discussion is around integrating these things, as the Moderator pointed out. They have different performance characteristics. My sense is (and this is not helpful for being a consultant) that the short-term integration issues are going away very rapidly. If you look at how hard RTOs thought it was going to be to integrate 10 or 15% renewables 20 years ago, they have found lots of ways of doing that. Some of the German RTOs, for example, are dealing with 70% renewables now, and they say it’s no problem at all. The short-term storage challenges are the challenges that go from a minute to a day. I think batteries, again, are becoming cheap so much faster that we can deal with that. The real challenge to me in these systems, over time, and it’s not happening today, is the longer-term storage issues. What happens with seasonal mismatches? But there are technologies to deal with that, and maybe we’ll get to that in the discussion.

So, alright, I think renewables are good. As I said, they’re going to get cheaper. So why don’t we wait? And, you know, there are some benefits to waiting. All these renewables will be cheaper in five or ten years. Why don’t we wait? That’s one reason for waiting. The second reason is, “Let me just freeride on Germany or China or whoever else is deciding to spend the money.” And the third is the idea by waiting we might actually learn about things that don't even exist yet today. So, those are all definitely good.

But I think there's some cost of waiting, for sure. So, cumulative emissions matter to this climate change game. And so, an avoided ton of CO2 today has value. How big that value is has become very complicated in the United States, if you believe the EPA, since the EPA's "social cost of carbon," I think, has been reduced quite significantly. Germany recently did a study where they sort of provide the equivalent of the EPA. They estimate the current cost of a ton of CO2 at $180, or 160 euros a ton. So, that means that the social cost of a ton of coal-fired generation is $180, in addition to the production cost. I can live with a lot of subsidies for renewables to proxy for that, and still have the renewables cheaper. For gas, it's just half of that. Still, that's a pretty big number.

So, now I'm going to talk about speed versus efficiency, since a lot of this group is about figuring out how to do efficient market designs, which is obviously a very important question. The point of this slide is that sometimes efficiency doesn't matter all that much. Sometimes you just need a solution, and so speed matters. So, that's one important point. And when we have sort of real complicated infrastructure or other challenges, markets tend not to be the primary driver of things. So, here are four pictures. The two top are kind of historic, if you want. So, that's the interstate highway system. That was not a market-based decision, the decision to build that out. Arguably, that has provided pretty significant benefits to the country economically. The second picture is basically the US government spending share of GDP over time. The only relevant thing there is that, early on, the thing goes up to 50%. You can all guess what the time period is. That's World War II. And the US is not unique. The UK had over 50% share of GDP. Russia has over 50% at that time. I haven't seen the German government statistics on that, but I expect Germany spent a whole lot of money on World War II, as well. So, fighting back against Hitler, that was seen as an existential threat, and a lot of money was thrown at it. I suspect efficiency was not a primary concern. It had to get done.

The bottom two pictures are sort of examples. So, you know, how much are we going to rely on efficient markets and designing efficient markets to protect ourselves against that sort of thingy (an asteroid) that is hurling towards Earth? Again, I suspect we're going to primarily focus on speed. And so, then, here we are with climate change. You know, we can have a discussion of whether or not that fits in that category, but assuming that this [terrifying slide of floods and destruction] is the possible outcome, I suspect getting stuff done really, really fast matters a lot.

I was speaking at a conference in Montreal, at the International Association of Energy Economists, and Mark Jaccard from Simon Fraser University made what I thought was a really important point about efficiency. If a policy that is not very efficient, but has a higher chance of actually being implemented, exists, relative to what we think is the efficient mechanism that has a low chance of being implemented, and not implementing a policy, not getting stuff done, is actually an option, then it's quite possible that picking the less efficient policy is better for society. If we say the efficient carbon tax is $200 a ton, and there is a 1% chance of getting that passed (and Mark Jaccard in his presentation has a graph that shows the carbon price in the United States since all economists agreed in the '70s that a carbon price was the right thing to do, and there's just nothing on the graph, because we don't have a carbon price)…so if one possible outcome is that we have a really efficient instrument, but it does not get implemented, or, alternatively, another possibility is that we pick something that's not very efficient, but ideally not very inefficient, either, that has a much higher chance of being implemented, we might be much better off implementing the not-so-efficient thing.

So, what's the bottom line of this? Is it that we should just throw an infinite amount of money at the climate change problem, no matter how we do that? No, obviously not. Right? First of all, it's important to note that perfect markets and perfect regulation can achieve the exact same outcome, in theory. That's, I think, one of the welfare theorems, if I remember well, from my good old school days. Now, of course, neither one is perfect in practice. Right? But the fact that regulation isn't perfect doesn't by itself mean we should use the market mechanism. It's a tradeoff. And so my sense is that with a continued shift of the technologies we use in the electricity sector, from having a substantial variable cost component to being almost exclusively fixed cost, it's worth contemplating the implications of trying to improve incentive structures through markets or regulation on capital investments and the cost of making those capital investments. A lot of the proposals to move away from the current regulatory approaches to foster more renewables suggests that we ought to expose these resources to whatever the marginal emissions intensity, or some other market price risk, to somehow ensure that consumers aren't saddled with inefficient investments. That might provide better incentives. But it's also important to recognize that exposing those resources to more risk means higher cost of capital, and so there is a price to pay for providing these better incentives. And I think it's important to at least recognize that there is this tradeoff when pushing for a certain direction.

So, for me, the bottom line is, maybe it's more important to create regulation that itself can adjust quickly to changing circumstances, regulation that can learn, than to create regulation that pushes more revenue risk on these largely capital-only resources, these infrastructure resources. So, for me, the lesson from what's happened in Germany…it's easy to trash feed-in tariffs, for example. I think feed-in tariffs work just fine, or something like feed-in tariffs, which are long-term contracts, basically. The problem in Germany wasn't that feed-in tariffs didn't work. The problem was that the regulatory system was not able to change the feed-in tariffs in line with the observed decline in the cost of these renewables. So, if I had to go back and advise the German government, I'd say, "You've got to have a mechanism…it's fine to provide revenue certainty to these resources, but make sure that the revenue certainty provided does not create windfall profits for the consecutive generations of resources." And I think that's where I'm going to stop. Thanks.

Speaker 2.
I agree with a lot of what Speaker 1 said. I'm going to get a little more into detail in a few areas on some of the integration issues and how renewables work on the power system. But, overall, I kind of agree with the theory that in the absence of strong carbon pricing policy, pro-clean energy policies are at least the second best,

if not third best, option, and probably the best option that we have, and therefore we need to be aggressively doing that, just given the climate math and the urgency of that…not letting the perfect be the enemy of the good. That is not an acceptable option.

Looking historically, renewable electricity standards and the tax policy we have at the federal level have been extremely successful at driving down the cost of renewables. Let me just flip forward so you can see how drastic this has been. On the left side you see the wind, and its unsubsidized cost. On the right you see solar. Very dramatic declines over the last decade. Obviously, these are both somewhat global commodities, particularly PV, so we are benefiting from Germany and China and other countries aggressively driving down costs through deployment. But, particularly on the wind side, these are large components. They don't ship that well. And so, a lot of this cost reduction has been due to achieving economies of scale and learning by doing here in the United States, through deployment. So, I think we need to keep in mind that this has been very successful.

I think that we are at a point, because of those cost reductions, that we can think about a transition to more efficient policies to drive this forward. One example of that transition is increasingly talking about "clean energy standards" as opposed to "renewable electricity standards." I mean, that's a good thing. Obviously, the goal here is reducing carbon. We should let anything that reduces carbon participate and receive equal credit. And you're seeing this at the state level in some particularly aggressive clean energy standards. As they get to really high penetrations, states are moving to a clean energy standard, which could apply to anything: gas, hydro, nuclear… They receive credit in proportion to their emissions reductions. There's been a federal bill, you know, modeled off of some of the bills that have been batted around for the last few years in DC. I think there's a lot of opportunity there. There are even things like technology-neutral tax credits that are geared around emissions. All these things, I think, are good options, in the absence of climate policy.

Just to put a little more political detail in there, looking at the Senate math and the Supreme Court math going into 2021, even under the best-case options, it's a very hard to get the math to work for a strong federal climate policy. Getting 60 votes in the Senate is essentially impossible for anything strong. With the current Supreme Court, getting five votes for a strong Clean Power Plan 111(d)-type regulation that moves outside the fence line and basically does a sector-wide emissions policy is extremely doubtful. I think there's a lot that can be done inside the fence line, under the Clean Air Act, that would basically reduce emissions at coal plants by shutting coal plants down, but we're not going to have something like the Clean Power Plan as it was proposed under Obama. I think that, with the current Supreme Court, that's a very risky legal strategy, so we need to be thinking about these other options. I think they can be quite efficient, if designed well.

Moving on, just to get kind of looking at things historically, we see massive reductions of carbon emissions from the renewables we've deployed already. Wind, in particular, has driven very large reductions, partially due to geography. Over half of our wind fleet is deployed in extremely carbon-intensive parts of the country-- MISO, SPP, the Mountain West--and it's displacing mostly coal generation, so it's producing a lot of carbon reductions, as well as reductions in SOx, NOx, mercury, all that stuff. So, that's been very successful. The time of production also matters. Wind, in most regions, produces more at night, so you tend to be displacing more coal, just because windmills are more baseload-type resources.

Solar has been mostly kind of in coastal areas that tend to be more gas-dominated power systems. However, I think solar, with cost reductions, is making very large inroads in places like SPP, MISO, and the Southeastern US, where it is already very a large presence. So, I think we are going to see very large carbon reductions there.

This is a map I put together. Each of these bubbles is a fossil power plant. This is from EPA's Avert tool, which is a very cool tool. I encourage you, if you haven't used it, to play around with it. It basically calculates emissions reductions associated with renewable deployment or energy efficiency. It was developed by Synapse Energy Economics, and it uses a statistical model of how power plants respond to the addition of a zero-emission resource to the power system. And you can see what I was just talking about, in terms of the geographic concentration. Wind has driven out a very large amount of fossil generation in the interior part of the country, SPP, MISO, as well as some of the coal plants in Texas. And this is a remarkable accomplishment. You can see the numbers there at the top. Two hundred million metric tons last year alone. That's about 11% of power plant carbon emissions, so this is making a big dent. Obviously, to address the carbon problem we need to be doing a lot more. But I think this is working. It's part of the solution.

I want to address some of the concerns that have been expressed about using pro-clean energy policies to address climate. One is that there is a market distortion impact any time you subsidize a resource through a tax credit or through, you know, a REC or a ZEC or whatever you want to call a clean energy credit, that is going to cause a market distortion. Certainly, it is true that, yes, when you add these low marginal-cost resources to the power system, that is going to suppress prices. Nobody's arguing with that. The argument I'm making here is that because the zero emission resources are typically also zero marginal cost, they don't typically set the market clearing price, and so the direct impact of the subsidy is typically not factored into the market-clearing price. It still pushes the supply curve out, of course, but it doesn't typically get factored into the price. And I did some analysis of this. Basically, as I went through and kind of looked at these major markets…(I did this about a year and a half ago when DOE was proposing the coal and nuclear bailout, and one of the arguments was, "Oh, well, these renewable policies are causing all these coal and nuclear plants to shut down.") We went through, and we looked at plants that announced retirements in these four market areas, and we looked at the pricing, the LMPs, at those nodes of those retiring generators. And you can see that there were some negative prices. That's the first column there. You know, 1-2% of the time they were seeing negative prices. However, in the next column, you can see that very few of those prices were in the range that would look like a wind project receiving the production tax credit offsetting. Typically, the production tax credit is $24 per megawatt hour, so you'd expect a wind project receiving the PTC to bid in somewhere in that range, about negative $20, reflecting that it's a pretax value. And we see that a very small share of the negative prices (again, negative prices are only 1-2% of prices to start with), a very, very small fraction of those negative prices were in that range. So, basically, what we're seeing here is that most of those negative prices are not even being caused by wind plants. They're being caused by nuclear plants that are inflexible, hydro oversupply, a coal plant that's inflexible or has a fuel contract, or something like that. And so, the argument that the wind PTC is majorly causing negative prices does not hold.

And then we went through, and basically asked the question, "OK, for these hours where the wind is setting the marginal clearing price, what would the impact be if we didn't have the PTC? And you can see, it's trivial. It's fractions of fractions of pennies. These markets have substantial penetrations of renewables, of wind in particular, and so I think the point of this is that the distortion impact is very minor, in terms of the market price being set by resources that are being incentivized. Certainly, you are pushing out the supply curve, and that's a separate issue, and, you know, we need to think about that.

Another myth I want to take on is the idea that by adding variable and uncertain renewables, you're going to cause fossil plants to cycle more, and cycling degrades their heat rate, offsetting some of the emissions reductions that you get from the renewables directly displacing, on a one-for-one basis, the fossil megawatt hours. It's pretty clear that adding renewable megawatt hours displaces the most expensive resource that would have operated, and that's almost always a fossil plant. So, the baseline assumption is a one-for-one displacement of fossil generation. And this is the question of, you know, as you cycle these fossil plants, do you see an increase in their pounds per megawatt hour emissions rate? And NREL did a very comprehensive analysis, and showed that, no, it's a negligible impact. You see about a .2% increase in the emissions rate because of the greater cycling. And that was at 33% renewable penetration. So, a pretty aggressive renewable level, and negligible impact. We do see that, obviously, there are other aspects of cycling that impose a significant cost in terms of O&M and other things on these fossil plants, particularly the inflexible ones. The coal plants. Arguably, some might say that that's a good thing. You're helping transition the fleet to a more flexible resource, and indirectly driving out some of that carbon through a backdoor means. But, regardless, the idea that we're significantly degrading the emissions benefits of renewables is not true.

So, looking forward, can we operate a power system reliably with large amounts of renewable energy? Absolutely. There have been a number of studies. This one was published in *Nature Climate Change* a couple of years ago. Christopher Clark did this analysis. There are a number of other studies like this done by the National Renewable Energy Laboratory, by the grid operators. Basically, you know, 50, 60, 70, even 80, 85% renewable penetrations are achievable cost effectively. That last 15% gets pretty expensive and challenging, just because of the seasonal storage issues and other issues like that. We can talk more about that. But, I mean, if we are serious about addressing climate and basically preventing climate catastrophe, getting to 85% as soon as possible, which we know we can do cost effectively, is a key thing to do. We can figure out that last 15% when we get there.

Across these studies, transmission jumps out. So, this is the Clark study. It shows a very aggressive transmission buildout. In all of these studies, that's a common element. You absolutely need transmission to make this happen. Given the variability and uncertainty of renewables, the easiest way to address that is by geographic diversity, basically because weather systems don't affect a large area at the same time. If you could just build your transmission grid big enough, you basically could avoid the duck curve issues, the capacity value degradation, energy value degradation, because you would have a much more diverse, stable, dependable output profile from the renewables. So that's a key element, I think, far more important than a lot of other fancy new technologies that are thrown around, like batteries and other things like that. They certainly have a role, in terms of providing megawatts and other fast response, but in terms of the high penetration scenarios, and dealing with this massive amount of megawatt hours of variable renewables, transmission is the vast majority of the solution.

You know, turning to some of those megawatt, as opposed to megawatt-hour, -type things that we need to deal with, renewables are actually quite good at that. Batteries are also extremely good at providing these megawatt very fast-type responses. This is work that Michael Milligan did. He used to be at NREL. He's now retired. I started this work, and he made it look a lot nicer and did a lot of work on it and got it published. Basically, he went through and kind of categorized the reliability services that different resources can provide. And what you can see is that renewables are now capable, through, you know, the use of power electronics and other things, of performing as well as or better than conventional power plants on almost all metrics. They can provide extremely fast response. You know, solar plants can curtail or provide whatever real power or reactive power output you want within a matter of cycles. No conventional power plant can do that. They would typically be hundreds of thousands of times slower, in the dozens of seconds timeframe. With inverter-based batteries, solar can do that in cycles. Wind can do it in a matter of seconds. So, I think we have this tremendous opportunity to take advantage of these new resources, the extremely fast and accurate flexibility they provide, and this is going to be a key part of the solution: using renewables to provide that flexibility. In a lot of cases, you don't need storage if you can just use curtailed renewables to provide flexibility.

This is a chart from an analysis that E3 did for the Tampa Electric Power System. It's a pretty small balancing authority, so, you know, it's not quite typical that you would see such a very large solar penetration without a lot of diversity. On the left side is an example of current practice, where you curtail solar, but you don't really use the flexibility of solar to provide operating reserves and the other things that are needed for system balancing. The right side is where, instead of just curtailing, basically what you would do is keep the gas plants on to provide the operating reserves. You're kind of committing your gas plant and using that to provide the flexibility. And that, obviously, results, as you can see, in a lot more gas burn on the left side and a lot of solar curtailment on the left side, as opposed to the right side, where, if you decommit your gas plants, you use curtailed solar to provide flexibility, provide operating reserves, even though you're curtailing solar to do that, you get a lot more solar megawatt hours, a lot less gas megawatt hours, and it makes the system a lot more economic for everybody. You get much more emissions reduction, and it's, you know, clearly the right way to go. We need to think about markets to get there, which is my final slide.

There is a paper that we put out, and there is a link. It's on our website. And I encourage everybody to take a look at that. It's about designing power markets for high penetrations of wind and solar. It goes through energy capacity and ancillary reliability services suggestions for how to design those markets, and I'm happy to discuss more of that in the discussion later. That's all I have. Thanks.

Speaker 3.
Thanks very much to Ashley Brown for the invitation, and Bill Hogan as well, and to the Moderator for your kind introduction. In the material I've provided for you, the answers to the questions of how far, how fast, and at what cost can renewables contribute to lowering electricity CO2 emissions are in bullet two. And they reflect research that I completed in 2017 as a senior fellow here at the Kennedy School. And in the research, I took a technology-neutral perspective to answer these questions, because renewables are a means to an end. They're not an end in themselves. And so, to answer these questions, it really depends on, what are your climate policy goals and timetables? And what's the state of technology?

So, to answer that question, how far should we go with renewables, there are two climate goals that I think are important in this regard. One's a price-based goal. So, how far should we go with renewables? As far as is cost effective if we put an appropriate price on CO2 emissions. And the current best estimate of that's about $50 a ton on CO2 emissions. Now, the second goal to think about would be a volume-based climate goal, which is that we ought to develop renewables as fast as it's cost effective to contribute to getting net anthropogenic CO2 emissions down to a level where it balances with the ability of natural sinks to remove them from the atmosphere, thereby stabilizing atmospheric CO2 concentrations and stopping global warming. That is the approach that is in the Paris Climate Agreement in Article Four, Paragraph One. The Paris Climate Agreement does not say we have to get to zero emissions by 2050. It's also consistent with the Under2 Coalition's Memorandum of Understanding that says that we need to get to about two tons CO2 emissions per person by 2050. So, if we take that two-ton kind of idea and do some arithmetic, it looks like it's appropriate to provide about half of that, about 2,400 pounds of CO2 per person per year for electricity, if we want to get to a sustainable, volume-based climate target.

So, then the question is, how fast? Well, if we're going to put a price on CO2, and have that translate into electricity price signals to influence demand and supply side choices, we've got investment cycles that take decades there. So, it needs a couple of decades for something like that to work through. Similarly, we've got two or three decades to reduce CO2 emissions to sustainable levels before we get to the 1.5 degree increase from the preindustrial level. So, for the question of how fast, the answer is, the next couple of decades.

On the question about "what cost," I think the public has an interest in achieving any of these long-term climate policy goals at the lowest possible cost. Now, since costs are a function of the state of technology, the analysis that I did involved a state of technology with a high probability of realization. And I think this provides a very useful benchmark for policy formulations and evaluations in general, and for renewables in particular. So, what did the analysis show? The analytic framework that I used employed an optimization algorithm. The objective function was to minimize the cost of employing demand and supply-side resources to reliably provide consumers in the year 2040 with the grid-based electricity that they want, when they want it, based upon retail prices that internalize all costs. The initial solution in this framework is an outcome that allows past climate initiatives to simply play out. We're not going to invest any more resources to do any of these climate policies, and we're going to start off with a zero price on CO2 emissions. So, then we're going to do subsequent solutions where we add in, in increments of $25 a ton, a price on CO2. So, what are the results? The initial point comes from the initial solution, where our electricity use per capita is about 8% lower than 2018 levels in the US, and our CO2 per kilowatt-hour is back to about 2010 levels. So, the question then is, how far, how fast? If we simply internalize a CO2 charge of $50, we go from the initial point at zero to $25 to $50. So, for our third solution point, the result there is, with this optimization, the most cost-effective mix of demand and supply side options. We reduce electricity use per capita by about 26%. We reduce the CO2 per kilowatt hour about 36% from the 2018 levels. And when you multiply those two things together, we've got a CO2 per person that's about 53% lower than current levels. So, if we then think about, well, how about reaching that 2,400 pounds per person per year sustainable level, that occurs where that isoquant is. So, that's the combination of CO2 per kilowatt hour times CO2 per person, and they all give you a 2,400. So that's what that isoquant is. So, you can see that it takes that sixth solution point there. at $125 a ton, to get to that sustainable level, and that's where electricity use per capita is 43% below the 2018 level, and CO2 per kilowatt hour is 64% below the current level. And, altogether CO2 per person per year is down 80% from current levels.

So, then the question is, how much? At $50 a ton, what we find is, wind and solar cost effectively comprise 6% of the generation mix. Now, a lot of people would say, "Gee, that sounds pretty low. We don't have a $50-ton charge on CO2, and the US right now is at 8%." But remember, this is an analysis where there are no mandates, there are no subsidies, there are no long-term contracts, there's no net metering at a retail price. What we've got is only a $50 charge per ton of CO2. This is very consistent with the analysis that's being done on the implicit cost of carbon. Michael Greenstone just put one out in April that says, you know, if you look at what are we implicitly paying for carbon right now, with these command and control policies, he puts it at $130-$460 per ton. Years ago, I did this analysis. I think it's safe to say that most of the implicit cost of carbon that we've seen is above $50 a ton. So, this actually jives with the analysis that's been done on implicit cost of carbon.

If we go to the sustainable CO2 level, wind and solar comprise 25% of the generation share. At what cost? Well, this puts together the average total system cost. I analyzed each electrical interconnection in the Continental US to come up with these results. I don't have a separate cost for just renewables, because it's an integrated cost optimization. So, when you add renewables, it affects the dispatch of gas. It does have a heat rate effect. It affects the reliability, how much capacity, and so forth. So, it's all kind of mixed up there. But, basically, we're looking at a 23-41% increase in the real price of electricity to achieve those 53 and 80% reductions in CO2 per person per year. Now, you've got about 10-11% of that average retail price that's revenue you're collecting from the CO2 charge. So, you can reduce 40-25% of that real price increase by recirculating that, or better yet, you can use it to offset some of the regressive impacts of these price increases. Bu the bottom line is that the costs are significant, even when you achieve it efficiently. And there's a strategic challenge then to set the size, pace, and mix of emission reduction to make these impacts politically tolerable.

Now, do we see any evidence that anything in the real world corresponds to the analysis that I've done? I've got the example of California. California set their first RPS in 2002. It's ratcheted up four times since then. And renewable generation has gone from 16 to 30% of in-state generation since 2002. 90% of that's been an increase in wind and solar. There's actually been a reduction in the other types of renewables there. The lesson is, the limiting factor on wind and solar is not their cost per watt or their cost per KW. It's this time dimension that we're talking about. So, what are we seeing? Solar currently provides 7%, on an annual basis, of California's annual electricity requirements. Two weeks ago, in an hour on June 1st, solar alone in California provided over 60% of the electrical requirement. So, you get a sense for the kind of variation we're talking about, and it's not highly correlated with the changes we see in aggregate customer demand. So, there's a big, big problem here. In 2016, the California ISO did a study of the operational challenges of 50% renewable generation, and they said that they would need to curtail 10,000 megawatts of wind and solar over large periods of the year and incur one to $1.5 billion in curtailment costs. What do we see? We see, actually, that the expected curtailments are increasing because of this misalignment. And this is what wrecks the economics of more and more solar in these power systems.

Now, even though we've got increasing amounts of California selling excess wind and solar into the energy imbalance market, they're selling it at about an 80% loss. But even with increasing sales at huge losses, we're still seeing increasing curtailments. Over the first five months of 2019 the CAISO reported that they have curtailed or sold into the EIM market 37% more of the available renewable energy than they did in all of 2018. So, it looks like this is a problem that's getting worse pretty rapidly. And people are saying that the duck curve is getting worse. The problem has been not just renewables, but it's the choice to subsidize and mandate renewables, instead of simply putting a price on CO2. The results there are that we do have significant wholesale market price suppression. We've increased the cost of the flexible generation, and the combination of increased cost and lower revenues from the prices means that in California, we're losing this ability to support the flexible generation that's needed. So, in 2014, California intervened and added flexibility payments. They've had reliability-must-run contracts. We're also losing negative integration benefits. The market distortions here are making it unprofitable to invest in high utilization, more efficient generating resources with relatively low CO2 profiles, and so that's where you get these accelerated retirements of things like nuclear plants. The solutions, like storage, are developing, but they're lagging. And even if you get all the mandated storage together, it looks like it's a little over a gigawatt. You've got a ramping need here that's already at 13 gigawatts. So, it's lagging, and it's not going to be sufficient to really address the problem. Despite all this accumulating evidence, there's technological optimism that's trumping any sensible adjustments here, and it's putting the ISO between a rock and a hard place.

So, what's been the outcome here? California has lagged the United States in reducing electricity sector CO2 emissions. There is no real discernable downward trend in CO2 emissions. The other thing that we're seeing is, despite lagging the country in CO2 emissions reduction, they happen to be leading the country in retail price increases. Now, what's interesting about California is, when you look at the affordability issue, affordability is not as important in California, because you've got a fairly temperate climate and higher than average median incomes, so that, for the typical household, affordability isn't as big an issue. The problem is, when you get to places like the Central Valley and so forth, where you don't have the kind of weather you have in San Diego, where it is hot, you need to use more electricity for space conditioning. You have lower median incomes. This is where you're getting this regressive impact, and it's hurting segments of the customer base. So, what we see, then, is it triggers a political response to get out from under these utility accumulating costs here. And what you get then are mechanisms like community choice aggregation and direct choice and metering at full retail to get out from under the utility costs that are accumulating. And what's happened is, you put utilities like PG&E in an unsustainable financial position. They've lost 42% of their retail sales to these other mechanisms, and that's before you layer on, with climate policy, the costs of preventing wildfires and underwriting the liabilities from wildfire. So, when all this comes home to roost, and PG&E goes bankrupt, now you've got billions of dollars of renewable contracts at risk of not being honored through the reorganization.

So, I think that this isn't a good second-best solution. We don't want to get in the way of the perfect. I think we've got a bad second-best solution. People don't realize how bad it is. I think the track record in Germany is one of failure, and not success. We see the same kind of problems in Ontario and Australia.

So, my conclusion is, accumulating evidence indicates that employing a patchwork of state and federal mandates and subsidies for renewables is making CO2 emission reduction more expensive than it needs to be, and making the probability of achieving long term climate goals less likely. Intermittent wind and solar PV are part of a cost-effective generating portfolio that achieves long term climate goals, but renewable development would be far better off with a climate policy that simply puts a uniform and appropriate price on CO2 emissions and uses the revenues to unwind command and control as well as manage regressive cost impacts, and under the current conditions of continued disharmony between policy initiative and market operations, this efficient benchmark provides a basis to evaluate interventions, such as flexibility payments, ZEC payments, resilience compensations, to offset the predictable consequences of these climate policy-driven wholesale electricity market distortions.

Speaker 4.
Good morning everyone. Thanks to Ashley and Bill for the invitation, and it's great to be part of this panel. There will be some overlap here, but hopefully some new food for thought. And we'll start by talking about policies. Some of these things are familiar. I'm sure a lot of them are, actually. So, we're bringing these renewables on, and it's a big part of getting to our climate goals, and renewables policies are very important in states where all the kind of climate action is happening in the US. This is a montage of familiar graphs that show which states have renewables mandates, renewable policies, and the states that have voluntary renewable goals. And the ones with letters around them that you probably can't read are the states that have fairly aggressive goals, above 50%. And there seems to be kind of an arms race going on here, with states getting higher goals and sooner dates. California did 2045, so New York had to do 2040. And then Colorado had to do 2040. The other thing about these goals is, they're in various stages of developing policies to make these things happen, but they're also broadening out. So, they're not just about renewables in most cases. They're broadening out, in terms of a focus on clean energy. So, it gives you a little bit of an opening.

Another thing that I want to point out is that the states that have carbon pricing are also using renewable portfolio standards. And, in fact, most of them started with renewable portfolio standards. On this graph you see all the states that either have a carbon pricing policy or are actively considering or about to introduce a carbon pricing policy. In the Northeast we have RGGI, and New Jersey's about to jump back in. Virginia has also passed a carbon pricing policy that they had hoped to link to RGGI. There are some complications going on there. And Oregon is also considering a cap and trade program that's economy wide. Currently, Hawaii is considering a tax. So, with the exception of Virginia (I believe Virginia's RPS policy is more of a goal and not a binding policy), all the other states do have a binding policy.

And the other point I want to make is about the increasing role that renewables are playing in reducing CO2 emissions. So, here is a graph that comes from a recent assessment of changes in carbon emissions by the Energy Information Administration. And what we see is the share of emissions reductions that come from switching away from coal to natural gas, primarily. And then the green bar is the share of emission reductions that come from renewables. And the two things to note about this graph is that the fuel switching to natural gas is always higher, but that the share of emissions reductions coming from greater use of renewables has been growing over time, and they're almost in parity here by 2017.

So, renewables policies are popular. They're occurring in a lot of states. They're ramping up, or at least the goals are ramping up. How cost effective are these policies? So, this is a difficult thing to assess. Speaker 3 mentioned the University of Chicago paper by Greenstone and Nath. And in that paper they looked at variability in the goals over time across the set of states that have RPS policies, and got a bunch of results, but a couple of them are listed here. An 11% increase in retail prices seven years after the policy was introduced. And the implied carbon costs, attributing all those costs to adopting these two carbon reductions, range between $130 and $460 per ton. Those of you who are on Twitter, I think, I saw Ari Peskoe come in on this. Anyway, there's been a lot of activity about this. If you have nothing better to do at night or can't sleep, I recommend energy Twitter. [LAUGHTER] So, this is a hard study to do. And one of the reasons that makes it hard is that these RPS policies are rarely implemented in isolation. And there's also a lot of heterogeneity across the states. I mean, many people put them all on a map, but there are different carveouts. There are different timetables, so they're not the same. Some of that heterogeneity's good for the type of econometric analysis that these two set out to do, but there are also confounding factors that may be difficult to sort out. The other criticism we read a lot is that the study misses other benefits, including the reductions in local air pollutants, and there's technology learning. And that's in the nature of another type of externality, which would suggest that even if we were pricing carbon at its social cost, be that $50 or $180, there might still be justification for encouraging new technologies if there's learning to be done.

So, picking up a little bit more on this point about the types of other externalities that are out there, both kind of on the innovation side, but also learning by doing, both learning by doing associated with implementing things on the ground, and maybe also these renewables integration challenges that we face. I mean, you can't really tackle them until you face them, and that's making us think about tackling them, and they are being tackled.

The other point is that it's very difficult to imagine getting a carbon price that is equal to the social cost of carbon, and everyone is familiar with how difficult this might be. In New York State they do have a proposal that the generators in the state or importing power into the state would face up to the social cost of carbon. So, going beyond what RGGI does.

So, you know, if there are policies that promote renewables, they can have both of these effects, and I think another thing to keep in mind is that, despite the desires of economists and others with good intentions to have efficient policies, the real world doesn't work that way.

So, how should we think about this? There are, as I mentioned, a lot of regions that have adopted carbon prices. They have these other policies. They were there first. And they also continue to evolve over time. I'm going to come back to that in a minute. People who work in political science have said, you know, that this policy sequencing maybe could help build support for carbon pricing.

Here we have the familiar duck curve. I've seen alligator curves. The Moderator was mentioning other animals. But this one's about solar, and the main point here is the challenges and the big ramp that's there at the end of the day. So, economists have looked at the effect of this abundance of renewables happening at particular times and what the impacts are on market prices. These two graphs are taken from a paper by Jim Bushnell and Kevin Novan that focused on what the impact of an additional gigawatt hour of solar in the top graph and wind in the bottom graph is on the hourly real-time market prices in California. So, what to focus on in this graph is that, in both cases, the solid line is zero impact, and the blue dots are the point estimates of the impact within a particular hour of an additional gigawatt hour of generation on the wholesale price. You know, the effects are fairly small, but they also are significantly different from zero. So, in particular for solar during the course of a day, they're negative, and then, of course, in the hours when the sun sets, they're positive. But they are significant impacts, and then the bottom graph shows similar results for wind. So that brings us to the issue of, OK, this is a situation we face. I mean, what are the strategies associated with optimizing renewables' role here in these markets? We've already heard reference to transmission expansion, in the Chris Clark study as a way of kind of bringing these remote renewables to market, but also kind of expanding the geography of markets, that's still a work in progress, and building transmission is not easy. I totally recognize that. Energy storage is another way to kind of deal with these temporal variabilities. You know, let's generate, with sun, for example, while it's abundant, store the electricity, and then discharge it during those ramping periods. And, you know, it will reduce a need for ramping, maybe, from other kinds of emitting plants. And we're not just talking about batteries here. There are other forms of storage out there as well. I know there's a big study on this that MIT is currently doing. I have to give a shout out to my colleagues, Josh Lynn and Jhih-Shyang Shih, on their recent paper in the *Journal of Environmental Economics and Management* that looks at battery storage. I think the context there is Texas. And they show that reductions in storage costs currently aren't necessarily emission reducing. It can be, if you're pricing carbon. But you kind of need these two policies together, is the point there. And with respect to the duck curve, of course, you need flexible generation, ramping products, or other things to meet the large shifts in load, as generation fluctuates.

One other thing I want to talk about here, and it's come up today, is the idea that electrification is something that we're going to need to achieve our goal. So, you know, decarbonizing the electricity sector and electrifying more energy use in buildings and transport, and how much does this impact demand for electricity. Well, there are a lot of numbers out there. EPRI has a study that finds between a 32 and 52% increase in electricity demand by 2050 through electrification. But I think an important thing to recognize about these types of loads that would be created by this process is, they can be flexible, and they could be used to absorb some of the renewable production and help with renewables integration, because there are opportunities out there for demand shifting, and they become even more real with these new sources of demand. So, a dynamic meter enables you to use these price incentives that are time differentiated, and, you know, that, I think, is going to be a really important part of renewables integration. Of course, people may be on Twitter all the time, but it's the rare folk who are watching the electricity price change on their phone, and the really bored. I hope none of you are doing that. But, anyway, you need smart technologies, you know, smart devices, to kind of integrate with these prices to kind of shift demand over time. The second picture here is a hot water heater, and I'm actually working on a paper with my colleagues Dallas Burtraw and Jhih-Shyang Shih on thinking about rate design structure and ways that electrifying the 48% of hot water heaters that aren't currently electrified might help to solve this problem. And also, of course, electric vehicles. So, they could be a resource. They have batteries, and they could store renewable energy during periods of peak production, and maybe, at some point, if batteries are up to this, and manufacturers will trust cars, or maybe you're leasing your car, and they have an arrangement with the grid, they could actually discharge back to the grid at some point in time.

So, a couple of slides about climate policy design. We know that imposing a price directly has been challenging in states, and Washington State twice turned that down. Maybe they didn't take the best approach. But mostly in states where we see carbon pricing, it's through a cap and trade program. And I want to put a plug in here. When I heard people refer to flexible policies, to thinking about, instead of as a fixed quantity, a price-responsive supply curve for allowances, that is actually what we have. So, in RGGI, and also in the WCI, there is this step function approach to allowance supply. And that means that the supply of emission allowances that is made available in the market is responsive to price. So, this graph is indicative of all the North American cap and trade programs that we have. And how is that? Well, they all have a price floor below which no allowance will be sold. So, in RGGI, that's roughly two dollars right now. And they all have a high price at which, if the allowance price in the market gets up to a certain level, additional allowances are introduced into the market, and those are referred to often as "cost containment reserve." And then in the recent RGGI program review, what they added was an intermediate step, which they call an "emission containment reserve." And what that is, is that at a certain price, up to a certain number of allowances will be withdrawn from the market. So, what does that mean? Well, if you think about things that could happen in RGGI, like a big decline in the cost of renewables, or a policy to promote renewables, or a policy in New York State to price carbon at the social cost of carbon, what might happen there is demand for allowances would go down, because there would be other things happening in the marketplace. And if you just had a fixed cap for emission allowances, that would basically be absorbed within the program, and you'd just have the price of allowances fall. But with this upward sloping supply curve, there's an opportunity for benefits to the environment. Emissions shift to the left, and the price of allowances come down. So that's a policy.

Next, though, I want to talk about a Clean Energy Standard, because pricing carbon is hard, but we do know that there are policies that sort of give you a technology-based goal and say, "Go at it, and you've got to achieve this goal with the market mechanisms here." So, let's talk about a Clean Energy Standard. What I mean by "Clean Energy Standard" here is analogous to a Renewable Portfolio Standard, where a minimum share of electricity sales have to come from clean energy sources, and that share goes up over time. And the thing about a CES, as opposed to an RPS, is that it's more expansive in terms of the technologies that are included--nuclear, fossil plants with CCS, and even combined cycle plants--and who gets credit just depends on how another feature is set, and that's the emissions threshold. If you're below it, you get credits, and if you're above it, you don't. So, this not only encourages the development of and investment in renewables, but it encourages fuel switching to cleaner gas. I have a colleague who says, "Let's just do a CES and make the threshold equal to a coal plant, and then you'll get everything. You'll get the affordable clean energy improvements and improvements in heat rates at coal plants, and you'll get other things." That's unlikely to happen. But, anyway, the crediting basically awards credits to non-emitters and low emitters, so it captures a bunch of margins and enables you to reap those low-cost emission reductions. Non-emitters get a full credit. Low emitters get partial credit. Others get no credit. So, the Smith bill, in New Jersey, which was mentioned here before, used this approach, with some particulars we can talk about later. And this is a graph that one of my colleagues made that was at the front of the room at the Senate when they introduced the bill. And if you're just looking out to 2035, the standard that what they're proposing would result in a 76% reduction in CO_2 emissions by 2035. This graph shows the share of generation from various technologies. So, coal is basically almost going away. Natural gas is getting smaller, but it's still hanging around for this crediting, and so is nuclear. And renewables are going up over time, and that's sort of how the system is unfolding. The other thing that we found, and we've done various studies of various proposals over the years, is that, depending on how it's designed, the clean energy standard can be almost as cost effective as a carbon tax. A modest impact on retail electricity prices. Of course, the impact of a carbon tax on retail electricity prices does depend on what you do with the revenue. An important thing here, though, is that you're creating a new instrument that provides value to clean electricity, and it's a different source of value. So, there's this credit scheme, and credit prices are part of the picture. Wholesale energy prices are substantially reduced here, and the interplay between the two is an important thing to keep in mind. So, it sort of reminds me of Speaker 1's idea. I mean, you're valuing clean energy, and that's what gets valued in the marketplace and traded, and what people get rewarded for, because the electricity retailers have to buy those credits anyway. But it can be fairly efficient from a carbon reduction perspective.

So, just to sum up, there are these policies. They're effective, potentially costly, and they play important roles behind reducing emissions today, which is sort of setting us up to be in a position to reduce emissions well tomorrow and develop these technologies that we're going to need more of. Transitioning from a narrowish renewable portfolio standard to a clean energy standard could lower the cost of achieving these emissions reductions in the short run. And we face some challenges with integrating renewables, but there's a mix of strategies out there. And I just want to highlight this electrification and demand-side strategy. I travel a lot in modeling communities. I don't hear a lot of talk about it there, but I think it's an important thing to keep in mind going forward. Thanks.

Clarifying question 1*:* Speaker 2, you talked about the season storage problem, which I don't think I've heard of before. Could you explain that?

Speaker 2: Speaker 1 mentioned it, too. With wind and solar, late spring is when you both have high solar and high wind. That's one of the lowest electricity demand periods of the year. In North America, electricity demand peaks in the later summer, due to air conditioning. Until you get to about 80-85% renewable penetration, it isn't much of an issue. Beyond that, you start getting just massive levels of curtailment, because basically you're just overbuilding the system, and you're curtailing a massive amount of wind and solar in the spring. You're overbuilding the system to meet what your peak demand will be in the summer. There are solutions to this. I think hydro reservoirs, for example, have the energy density, in terms of megawatt hours, that batteries and other things do not, to help with this. And, you know, that's how Europe, to a large extent, is integrating renewables, because it has the Scandinavian reservoir hydro system. The US has larger reservoirs to our north in Canada that we can probably utilize for a similar service at some point, particularly as we transition away from using hydro reservoirs as energy sources, to using them more as flexibility storage resources. I think there are other solutions beyond that, as the carbon prices get high enough.

Again, electrifying everything is going to add a lot of flexibility and allow more dispatchable load. I think, for the seasonal storage, we can start doing synthetic fuel production. So, carbon capture, and then electrolysis of hydrogen, using that to produce synthetic liquid, gaseous, even solid fuels that we can store and transmit in the existing pipeline and other infrastructure we have for dealing with those types of fuels, I think, will play a role. This is a problem that we'll see, hopefully, soon, but it's not until we get to 85% renewables. So, we've got some time to think about how to solve that before it gets here.

Clarifying question 2: Speaker 2, one of the myths that you were breaking is that renewables can't provide some of the reliability services. And so, I'm wondering if, for the uneducated, you could explain, like, can they go reg up and reg down and do that regularly? That came as a surprise, because we hear that we need fossil fuel generation to manage that.

Speaker 2: Absolutely. That's being done today. So, for example, in Colorado, they're outside of a market, so they have, I think, more flexibility to operate their plants however they like. They often, in nighttime hours, will basically have very high renewable output and very low demand, and they'll turn off their conventional generation and use the wind plants to regulate frequency. They put their wind plants on AGC (automatic generation control), so, like, every four seconds they're basically getting pinged and going up or down in response to that signal. The wind plants are extremely fast and accurate in providing this response. And so, they're able to get away with using less frequency regulation, because of the accuracy and the speed of the response. And this is done in other places as well. For example, in ERCOT, wind plants now provide a large share of the total system frequency response, mostly for high system frequency. So, when system frequency is high, the wind plants will curtail in seconds or less and bring frequency back to nominal. If wind plants are curtailed going into the event, they can also provide upward response. And that's the thing. I mean, as you get to these higher penetrations, we are going to have significant curtailment in terms of the number of hours, and you will have that resource available to provide upward response, particularly for these contingency events, where, basically, you've lost a major coal or nuclear plant for a matter of seconds to minutes. You need a large injection of power to stabilize frequency. Renewables can do that, even if they're behind a transmission constraint. You can overload a transmission line for seconds and minutes and not cause a reliability issue and provide very valuable services to the grid. There's also direct to power voltage control, the power electronics in wind and solar plants, extremely fast and accurate control of that. They can even do it at night, for example. A solar plant can do it at night. A wind plant can do it when it's not producing power. Basically, you bring grid power into the plant, run it through the power electronics, and provide the voltage regulation that you need. So, there are a lot of really neat tools, just given the speed and accuracy in the power electronics of inverter-based generation.

Clarifying question 3: Thank you. Thanks to the wonderful panelists. Speaker 3, I had a question for you. Do the 23 and 41% rate increases reflect the cost of large amounts of curtailment? And then I also had a question on the reference to natural gas water heating. In terms of changing that over to electric, what is the plan? I assume we wouldn't be tearing out people's existing hot water heaters, so there must be some sort of plan for how to price or prohibit future installations of those or replacing existing ones. So, I'd just like some idea of that, please.

Speaker 3: So, to answer the question about curtailments, the answer is, yes. The optimization routine takes, on a grid basis, the observed recurring hourly annual pattern of renewable output, the same way I'm incorporating a recurring annual hourly pattern on the demand side. And when we get this situation where you've got too much supply versus demand, it does curtail, which is one of the primary reasons why, as I start to get into this kind of 10-25% range, the economics on the renewables really start to fall off. And it's a serious limit on going much further.

Speaker 4: So, in thinking about electrifying hot water heaters, the project that I'm working on, I probably confounded the ultimate goal, perhaps, with the project, which is focused on three cities and looking at rate design and trying to understand what it would take to make it worthwhile to do this from a rate perspective, and what the environmental implications are. I will say that a grid-connected electrified hot water heater is an important part of what a lot of rural cooperatives do currently to prevent having to pay high prices on peak. So, there are a number of them where they'll give people a hot water heater, like a $500 hot water heater, as long as they can grid control it, because they avoid having to buy energy at peak or build new peakers. And so, I think there are important economic opportunities there, and that's what we're trying to identify in our work.

Speaker 3: Let me just add one thing to the response, which is, when people talk about, "Well, the solution here is to build more transmission, so that you could be like California and sell elsewhere what you can't use," there's kind of a fallacy of composition here, because California, they've got someplace to dump it. But if you look at the Western Interconnection as a grid, if everybody looked like California, there's no place to dump it. And so, that's curtailment. And so, when I look at this on a grid basis, and I start to move these renewable shares up, I've got no place to dump it. And so, the curtailment becomes pretty serious.

Clarifying question 4: I have a clarification question for Speaker 4. I think page ten of your presentation had this potentially counterintuitive result that power generation in-state and imports for California did not show any CO_2 reductions. I wonder if you could clarify why this result seems to be there, and if it has something to do with the San Onofre retirement, or if it has also to do with the fact that you're not counting the exports. And so, if you just had a bigger cross section of the West, and you looked at everything, not just the imports and in-state, that the exports, which are, I guess, all the solar, that's zero carbon, they'd actually see a reduction. So that's the question.

Speaker 3: Yeah, the California CO2 story is actually interesting, and it's very complicated. But if you look at the graph, what you'll see is that the need for flexible generation in California meant that, from 2002, when they passed the original RPS, to the present, they became a fossil-dominated in-state generation mix, so they relied more on natural gas, not less. And, yes, the result here is, San Onofre closes, I think that was 2012. You see the effect there, which is, you're closing down nuclear. You're replacing it with renewables integrated by gas. Your CO2 emissions are not going down as a result. And now you've got Diablo Canyon that's going to be coming off. So, the CO2 emissions from in-state generation in California aren't trending down. And all of the reported reduction in CO2 in California comes from the assumed reduction in the CO2 content of imported electricity, which accounts for about one-third of their supply. The problem here is, the way they do the CO2 accounting in California, it does not reconcile with actual power flows. So, there's a lot of resource shuffling that's giving people a false sense that the power that's going into California has a lower CO2 content than it actually does. So, yes, all of the CO2 emission reduction that California talks about comes from its assessment of the CO2 content of imports, which is not what their policies are affecting. So, I think the California policies look to be very expensive and very ineffective.

Clarifying question 5: Thank you. And thank you to the panel from me as well. My question is for Speaker 2. On your third slide, where you have the Lazard projections of solar costs among other things, my question is, how is utility-scale defined, as opposed to other sizes?

Speaker 2: I'm not sure exactly what Lazard uses for their breakout of utility-scale versus distributed. I would assume that it's megawatt or a couple of megawatts. They draw the line between distributed and utility-scale. And utility-scale is basically, you know, large-scale, transmission-connected plants that are the dominant source of most PV, maybe like two thirds of the PV, going forward, with about one third distributed.

Clarifying question 6: I have a set of clarifying questions for Speaker 3. I was struck by your isoquant chart and the reduction in per capital electricity consumption. So, I'm curious, what's driving that? Number two, did you think about electrification of end uses and what impact that would have? And, number three, when I look at your chart on price increases, these are price increases per megawatt hour, and a lot of that is in the fixed cost category. How much of that is driven by your analysis of reduced consumption?

Speaker 3: If you click through to the paper that's cited there, there's a whole outline of the basic analysis on the demand side. And there are three really important pieces to that. One is, you know, to connect electricity use to economic activity. And so, there are very clear and solid representations there. Of course, we've got residential and commercial growing faster than industrial, which affects some of the electrification. We do see evidence of electrification in industry, but we also see evidence there that our industrial mix is moving away from electric-intensive activity. But I've taken that all into account and put together what

I think is a very logical projection of where demand would be. But there is a very important thing here. I've got a very solid estimate, in my opinion, of the long-run price elasticity of demand, and that's the biggest thing you can see from the chart. If we put a price on CO2 emissions and confront people with it, we're going to have a higher price of electricity, and people are going to react, in the long run. And so I've got a price elasticity of demand there of about a negative .6, as I recall (it's in the write up there with all the statistical background), but the point is, in doing the quantification, I estimated the effect of an additional dollar of investment in rate payer-funded efficiency programs, so I'm able to come up with a positive and increasing cost to invest to increase efficiency beyond what customers would choose to do themselves, and you can see that that's one of the demand-side options that's in the optimization routine. So, the combination of the price feedback, the price elasticity effect, the effect of economic expansion on rate payer-funded efficiency, and the kind of underlying trends we've got, particularly in the industrial sector, are what's behind those kind of demand numbers.

On your question about how my projected price increases relate to fixed costs, what you see is, and I think California is a good example of this, you've got price suppression in the wholesale market, so you see a downward trend in the wholesale price of electricity. You see an upward trend in the retail price of electricity. And that's exactly because, with these policies we've got to mandate the renewables, you are replacing variable cost with fixed cost. So, yes, the fixed cost component of total electricity cost is increasing as you shift this mix.

Clarifying question 7: We have a lot of existing technologies like nuclear, which is very important for the clean energy programs. And we're trying to subsidize that. At the same time, we're also subsidizing the newer renewable energy technologies. And is there a balance? I mean, at what point can't rate payers bear the cost of that much subsidization?

Speaker 3: As I ended my presentation, I said, if we're not going to do this right, by putting an appropriate price on CO2, these kind of results give us a benchmark of what the lowest-cost options would look like, so you do look to a place like New Jersey or New York that have intervened. They're subsidizing renewables, but they realize that that's going to create a distortion. If you close down the nuclear plants because of the suppression in market prices, you're going to end up going backwards. And so, it does create an economic argument. If we're not going to do it right, then there are things we can do to offset these predictable market distortion consequences, and keeping the existing nuclear plants running is one of the most cost effective things my analysis shows you can do if you want to achieve these kind of long-term CO2 targets, so there is a good argument for that. And so, yeah, instead of letting price signals do it, you can look at this kind of least-cost analysis and say, "Well, here's how much renewables I want. Here's how much nuclear I want. I want to subsidize the gas in order to get the flexible resource." It's a much less efficient way to go about it, but it does give you some guidelines.

Speaker 2: You could say, too, right, that the clean energy standard approach is one that would also make progress in the right direction. For example, probably also compared to what these states have done, where they say, “Oh, I’m now not going to just give a separate subsidy to renewables. I’m going to also give a separate one to nuclear,” and the two things are kind of delinked, as opposed to just having one approach, where you see, OK, who can do it the cheapest?

Clarifying question 8: I feel like I may be the one person in here defending California today. And I know this is supposed to be questions, but I do feel I have to make one clarifying point here. And, Speaker 3, I think I agree with your overall premise here, that the most cost-effective way to get to some of these goals is pricing carbon, and not these command and control programs. However, the chart you have in here that shows this carbon emission from the electricity sector in California, is contrary to the people you were citing. So, CARB and EIA show, for the electricity sector, both import and in-state, an end decrease in carbon emissions since 2020. So, I’m not quite sure how that that meshes up with what I’ve just pulled up on the California Air Resources Board table, or EIA’s, and the scale is different. So, I just want to point that out, that I recommend people to go look at the other sites and see what those sites are saying, and then maybe we can have a conversation later on, on why that difference is.

And then the other thing I want to point out is on curtailment. I would also agree, if you get to a certain point of curtailment, that becomes a problem. I would point people to a June 5th article in the *LA Times* on solar curtailment, which is actually, as little of a fan as I’ve become of mainstream newspapers doing energy reporting, is actually quite a good story on an energy topic. It does point out that last year 2% of total solar production in California was curtailed. This year it is going up dramatically, but that’s up to the 4% range. So, I agree that if you get to a certain level, it’s bad, but let’s not miss the fact that it’s at a pretty low level right now.

Speaker 3: Yeah, the data that I showed is data published and made available by CARB. And what I said was, I don’t see a downward trend in CO2 emissions in California. And the reason I say that is, on any particular year, when you’ve got a high hydro year…so you have to hydro-normalize this data, because that can be misleading. So, if you pick dates, you know, selectively, if you’ve got a high hydro year, you can say, “Gee, look, our CO2 emissions are down.” We also had the effect of, with the Aliso Canyon gas storage facility failing, it reduced California’s ability to burn the gas they wanted, which had the side effect of creating an operational problem that reduced CO2 emissions in that year. So, I’m looking at a long-term trend here, and my basic proposition is, particularly as you look at Diablo Canyon coming out, I don’t see downward trend in CO2 emissions in California. And even if you’re selective about years, it’s pretty clear that California’s lagged the US electricity sector in CO2 emission reduction.

General Discussion.

Question 1: First, I want to say, I’m really appreciative of this panel. I thought it was just terrific, particularly in the spirit of the Harvard Electricity Policy Group, where, as we always communicate to the speakers, the most important thing to be is, well, provocative. [LAUGHTER] And so we want to push the envelope and try to talk about the ideas.

I do have a question for the members of the panel. I think that the simplest way to phrase this is to put it in the context of two different numbers we heard about the social cost of carbon. Speaker 3 mentioned $50, and Speaker 1 cited this study that comes from Germany, where it was $180 a ton. I haven't seen the study (but I want to), but I have looked at this problem before, and I'm happy to go into explaining why I am going to say what I say now. But that will get us off into some of the details. It's all about a discount rate story. But I just don't think $180 is a credible number. I don't believe it. And I do think $50 is a credible number.

And now my question is about the second-best story. I think that framing the problem this way, as Speaker 1 did in the beginning, in talking about the probability of adoption of the policy, I think that is a helpful way to think about that problem. And just shorthand, if you told me that the optimal social cost of carbon is $50 a ton, but we can't get it politically, but we have a secret method for getting something which is equivalent to $75 a ton and would work about the same as a $75 a ton of carbon thing, which would be too much, I would say, "Great. Where do I sign up?" That's only 50% off. I'm willing to live with the second-best story that's 50% more expensive at the margin that we're talking about. $180 is a completely different story, and what I worry about there is, if you get in a policy that's equivalent to $180, which is what Michael Greenstone is telling us is what we're doing here in this context, what I worry about is the backlash problem, which is, it starts with, "Don't worry, it's cheap. It's cheap, and it's going to help you grow your garden better. It will babysit your kids. There are all kinds of side benefits for this that we can take advantage of." And then the costs start rolling in, and then all of a sudden you get people who then say, "Well, wait a minute. Stop, wait, I thought this was supposed to be cheap?" And it turns out it's not cheap, and it's expensive, and you get a backlash. You can call the backlash Ontario. You could call the backlash Alberta, with the recent government. There's a long list of places where this continues to be the case. And I've always been worried about this, and I've been very supportive of efforts over the last several decades of, "OK, if you can get a cap and trade program, good. If you can get something that's cost effective, good. I'm all in favor of it. I'd rather have a tax, but I'll go with these second best." But I'm worried about the backlash problem. And we'll lose another decade and yet another decade, and we're not the problem. It's the other parts of the world, like China and India and all these other kinds of places, where this problem is even more severe, and we're not going to address it. So, when you calculate that probability, the backlash problem into it, I come out the opposite way, which is, I think it's better to fight for $50 a ton as a carbon tax and get an efficient solution. It's politically difficult, but so is everything that's worthwhile doing. And so, we should just keep hammering away, and not kidding ourselves with all this other stuff, because it isn't going to work. So, what about the backlash problem? And where do we stand in terms of trying to get a policy which is actually going to be reasonably cost effective, and actually get something done?

Respondent 1: I can start, unless somebody else wants to go first. I think the likely cost range of these pro-clean energy policies, pro-renewable policies, is likely on the low end. I showed the cost reduction trends. That doesn't show future cost reduction expectations. But the trend continued downward. PV costs continue to come down. Wind costs continue to come down. As we're rolling up the tax credits, there are actually a lot of cost reductions that come about because the financing structure can shift to more debt, as opposed to tax equity. So, you know, the Wall Street bankers who are doing these tax equity deals are no longer getting their piece of the pie. So, we're looking at $20-30 per megawatt hour unsubsidized cost in the early 2020s. A number of the major large renewable developers say that's where they see the market. That's extremely low cost. It's below avoided cost for operating almost any existing fuel of asset. So, I think, you know, the cost we're talking about here is very manageable. Again, curtailed renewables can provide a lot of services. And, obviously, we need to do transmission and things like that. But that investment has a number of other benefits that helps keep the cost low.

In terms of, you know, the backlash, I absolutely agree that that's important to avoid, but I think, you know, there are two kind of questions about what policy is right. There is, what is the policy, but there's also, where do we implement it? And I think we run the risk of backlash by having blue states that don't have a lot of good carbon reduction opportunities aggressively pushing the envelope on things like carbon pricing, giving carbon pricing a bad name. We need to think about, not just the policy, but also where it's implemented. And I'd argue that having a national policy that is able to utilize the low cost emissions reduction opportunities that we have on a national basis is a good way to keep the costs lower than having progressive blue states going out and doing extremely aggressive, good policy, you know, carbon policy. For example, New York has done a bunch of analysis, and I'm glad they're doing what they're doing, but the reality of New York's power system is, there's no coal. The renewables are location-constrained and need very expensive, very difficult to build transmission to be built and to be effective. And so, you can have very high carbon prices, and get relatively small emissions reductions. I'm not saying this is a bad thing. I'm just saying this is the reality. And suppose that almost anywhere else in America, where you have a lot of coal generation that can be very easily and cost effectively displaced by using gas, by using very low-cost renewables, that just are not there in New York… And so, having a national policy that allows this broader supply of low-cost resources that can reduce emissions, I think greatly reduces the cost of the policy. And it's probably more important than whether the policy is a carbon price or a clean energy standard or something like that. So, I'd argue that we need to do something that can happen, we need some policy that we can do on a national basis, whatever that is, even if it's not the most economically efficient policy. I think that's the priority, getting something in place nationally, so we can use the abundant low-cost emissions reduction opportunities we have.

Respondent 2: I'll try a little, too. I agree that, you know, it's a repeated game, and it's kind of, we won the first battle, but we lost the war. That's one part of the equation.

The other part is, how expensive is it? You would be uncomfortable with doing stuff that equates to a social cost of carbon of $180 a ton, even if it were political feasible, because of the backlash down the road, ignoring the sort of the PR war. I guess I'm les worried about spending $180 today, because the denominator matters. I mean, if I told you, “Here’s an opportunity to reduce carbon by one ton, and it’s going to cost $180, and, oh, we all have to pay for it,” that’s not going to matter a whole lot. So, you know, this goes in some sense to Speaker 2’s point. The real question is whether the idea that we’re going to work our way up the marginal abatement cost curve, and whatever we do today is going to be cheaper than what we’re going to do in five or ten years, whether that’s actually true, or whether the underlying dynamics that we’ve set into play here actually will lead to a dynamic where that’s not necessarily the case. But by the time we get to a large-scale deployment of these, call them “renewable resources,” we have, through a combination of factors, gone down a learning experience curve, so that, actually, for the bulk of the decarbonization, the cost is no longer $180. It doesn’t mean we’re not going to get back to that marginal abatement cost curve down the road. Once we’ve sort of replaced the bulk of the fossil generation with the bulk of renewables, and then, whether that’s at 80% or 90% or 70%, we run into the question, “Oh, what are we doing about seasonal storage?” for example. But, apart from the PR stuff, I would be happy to spend some money on more expensive carbon abatement. In some sense, you could argue, right, the cost of carbon abatement from R&D spending is infinite, until you get to the point where you actually have some technology that reduces carbon emissions, and I think that maybe, as a point of non-contention, we should spend a lot more on R&D to find the solutions for this.

Question 2: Well, that, I guess, gets to something else. What is the start point of all of this in the different states? I mean, is it fair to criticize California for not reducing emissions as much as a Midwest state that had tons of coal to close? Or the places that are already pretty clean, and it’s going to be expensive to get the next ton? Are we just going to wait there until we have a national policy? So, how do we factor that in? I think it gets a little bit to like, what’s the next best?

Respondent 1: The starting point, I think, links into this question of backlash. I don’t think it’s a coincidence that the places that have been on the leading edge of trying to mandate and subsidize renewables are high income places, where the concern about electric affordability is fairly low. So, in that regard, California is the fourth best with regard to affordability, if you look at the price times usage as a percentage of median income, which is why they can afford to shoot themselves in the foot, where other places can’t. But I do think that political backlash is a predictable consequence of these public policies that are based on these simple LCOEs that are time ignorant, non-integrated, dislocated, and incomplete. And if you look back through time, Gray Davis, Arnold Schwarzenegger, Governor Brown, and Kevin De Leon, who sponsored the 100% California legislation, they all referred to simple LCOE metrics saying that renewables are going to lower your power bills. And it hasn’t happened. And if you look at the Lazard LCOE, you know, that Speaker 2 referred to, on page two of this latest edition, their 12.0, they say that certain alternative energy generation technologies are cost competitive with conventional generating technologies under certain circumstances. So, if you go to the footnote as to what are those circumstances, well, for solar PV, it’s that you’re located in Phoenix, compared to gas. That’s kind of typical. And it also excludes potentially significant factors, including capacity costs, integration related costs, or carbon costs. So, other than that, the cost comparisons look pretty good. And the bottom line here is, we've got policy being formulated on very flawed simple LCOEs. It will naturally fail. It will then generate this backlash problem. And I think, in the long run, we're worse off doing politically feasible things that have a backlash and undermine the initiatives and waste the money that we've got to throw at this, than doing the right thing from the start.

Respondent 2: I can respond. First, it's actually true that levelized cost does not capture everything. And DOE's Energy Information Administration has come up with a very good way of accounting for that. They do levelized cost, and they also do a levelized avoided cost. And, basically, that levelized avoided cost represents the value of the energy that's being provided and accounts for time of production, dispatchability, things like that. And what they've found is that the levelized avoided cost for wind is about 10% lower in value on a per megawatt hour basis than a more dispatchable gas combined cycle plant. PV, at low penetrations, is about 10% higher, on a per megawatt basis. Obviously that declines as you get, you know, into the duck curve, and the capacity value drops off, and things like that. But, regardless, the number is relatively close. It's within a 10%. And this is at relatively high penetrations, you know, in places like ERCOT, SPP, MISO. So, these integration costs, and the other kind of declining marginal values of renewables are not as drastic as Speaker 3 makes out. Speaker 3 focuses a lot on California. I think there are a number of problematic aspects of that. There are the Onofre costs. There are substantial costs associated with bailing out that plant. It hasn't been mentioned, but obviously California was in a drought for many of the latter years of this chart. It's a very hydro dependent state. Therefore, both emissions and costs went up as the hydro resource was not available. And others can more aggressively defend California, but I would point out that early adoption of distributed PV was a very expensive proposition. And it doesn't reflect ongoing costs, which, again, are much, much lower than they were just a few years ago. And also, you know, I think most of the focus in the industry is moving towards utility-scale generation, which is a lot more cost effective than distributed PV. And one more point. California has a number of challenges. Being isolated as a market surrounded by non-market areas, that limits the flexibility, the transmission scheduling and other things like that that. Speaker 3 focused a lot on California. If you looked the experience in SPP and ERCOT and MISO, places that have equivalently high renewable penetrations, the emissions trajectory and the cost trajectory is dramatically different than California. Costs are very manageable. Emissions have come down drastically. Again, you know, I think it's like the New York example. You can find examples of places that are willing to incur high costs and do policies in certain ways that doesn't reflect the reality of where most of the emissions reductions and most of the renewables are being deployed.

Respondent 3: I think that there may be a way to kind of pull things together and just to come back to this clean energy standard idea as a potential federal policy, and some analysis we've done on this. In the Smith bill, and I'm not advocating a particular piece of legislation, but it might be a creative approach, there's a national goal that ratchets up, but each state is sort of starting from where they are. And so, they have different trajectories over time. But it creates a nationally traded instrument, which is this clean energy credit. And, by virtue of including both some emitting generators and non-emitting generators to a large extent into this one big pot, including nuclear, you get a lot of cost efficiencies. And we find that it's pretty close to a carbon tax. Now, design and details matter there, but I think there's potential for that type of approach to get away from some of the potential cost complications of a more targeted renewables policy.

Question 3: So, first of all, thank you all. This was really great. What I think Speaker 3 concluded, in California and elsewhere is, you shut down the nuclear plants. You increased carbon dioxide emissions. And I'm very interested in that issue. Speaker 1 talked about where we need to get to 30, 40, 50 years from now. And the existing nuclear fleet is 40 years old and older anyway, and we really don't have a lot of experience with what's going on inside that core when we run plants that long. And so, I'm putting aside how I feel about this entire enterprise. I'm a little bit concerned about saying keeping the nukes running forever is a great idea if you want to reduce carbon emissions, because I'm not sure how much longer they can safely operate, and when I look out at the periods that Speaker 1 was talking about, where we need to get down close to zero, they disappear anyway, in all likelihood. So, I'm just wondering--all of the policies around nuclear and ZECs, do they make sense? Should we be trying to keep them operating as long as possible to keep CO2 emissions down? Or should we be responding to the economics, and just acknowledging that they what they are?

Respondent 1: With regard to nuclear plants, there are a couple of important things. People have been showing that there is price suppression by choosing to mandate and subsidize renewables instead of putting on a carbon price, and that it is affecting the markets. Now, there's a lot of disagreement as to how significant that price suppression is, but that's affecting the cash flow of nuclear plants.

What people are not remembering is that if you had the right price, it would internalize something like a $50 charge on CO2 emissions. If you did that in PJM, for example, knowing what's on the margin in PJM, the average market clearing price wouldn't be $35 a megawatt hour. It would be $17 per megawatt hour higher than that. So, if we had the right prices, if we had short-run-marginal-cost-based competition, where we counted all the costs and cleared the prices, nuclear plant viability wouldn't be a question.

Now, looking long run, you're absolutely right. When you look at the current expiration dates on the licenses, if you'll notice, with my starting point, my nuke had gone away. And that's because I let them close down. I put in a fairly high cost, about four times the current going-forward cost, for refurbishment for the life extension, because I didn't want to produce a 2040 answer that then in 2045 falls apart because all the nukes go away, so I incorporated nuclear life extension in there. Must nukes people are pretty confident they can go another 20 years. People are doing analysis right now on that, but, as I showed you, to reach a sustainable volume-based goal, long run, you're going to need some new nukes in most places.

Question 4: To the backlash question, I just wanted to echo a little bit of what Speaker 3 said about Germany. The German residential electric rate is five times that in the United States.

Respondent 1: That's incorrect, by the way.

Respondent 2: Sorry. I am a German citizen. I have a house in Germany. I can tell you, you're incorrect.

Questioner: Well, I don't know what your bill is, but the statistics are unimpeachable. I have shown the graph in the column that I wrote, and nobody ever said it was wrong, and also emissions in Germany have not been going down, unlike in the United States and the rest of the European Union. So, I don't think Germany is a very good example, and I think the torches and the pitchforks would be out for US regulators long before we ever got to something like the German residential rate.

I just want to say one thing about transmission. These big transmission lines, the maps that go up, and the conceptual plans that have been coming out for years and years now, and it started with PJM and MISO, and NREL does it, and everybody else does it…. As I've tried to point out, electrons do not actually move. Energy moves, not electrons. So, in the grid, we create more capability, essentially, by displacement. So, the analogy to the interstate highway system, where cars actually do move on the highways, I really don't think that works. The bottom line is that, almost always, the best way to create more transmission capability is to upgrade the existing grid, reinforce the existing grid where it exists. For example, Southwest Power Pool has been very, very effective thus far in integrating very large quantities of wind, on a relative basis, by upgrading the grid. Periodically, we have reports of new studies that claim to show that these big HVDC lines are going to make economic sense, but they really don't. Typically, they underestimate the cost and of course the political backlash that's associated with these kinds of large lines that would cut across huge swaths of the United States.

So, for the "green route" in the Upper Midwest, you do a back of the envelope cost for transmission service on that project, and it would be $33 a megawatt hour. The difference in energy prices between its source and its sink is $2.00. So, how are you going to justify a $33-megawatt hour transmission line, when you stand to make, essentially, on an economic basis, $2.00?

Assuming I haven't put enough on the table, I do want to ask about conservation, because we really haven't talked about that. Everything has been on the supply side. And I just want to ask if the panel would talk a little bit about the demand side. How do we make sure, for example, that we're doing the most effective thing on the supply side, and we're not missing something on the demand side? Just as an example, LED lighting has reduced electric usage in the United States by twice as much as all the rooftop solar in the United States. And it seems to be missed in a lot of what we tend to talk about.

Respondent 2: Let's talk about Germany for a little while. Everyone has to be really, really careful when making these sort of broad stroke comparisons. So, the average US retail rate today is somewhere between ten and 12 cents a kilowatt hour. Here in Massachusetts, it's closer to 20 cents a kilowatt hour. Germans' average retail rate is in the 30-euro cents per kilowatt hour range, which is roughly 35 US cents a kilowatt hour. So that's not five times the US average, and it's definitely not five times the Massachusetts average.

Questioner: I meant to say three times. I'm sorry if I said five.

Respondent 2: OK. [LAUGHTER] Call it a rounding error. [LAUGHTER] Of those 30 cents, ten cents are taxes. Alright? So, in the United States, we don't levy general taxes on electricity. In Germany, you do. So those are the kinds of differences that have to be respected when you make broad strokes comparisons. The average German electricity bill is roughly the same as the average US household electricity bill. So that's another sort of fallacy, sometimes, where we just mistake prices for bills. As a share of disposable income, what Germans pay is very comparable to what Americans pay. So, I think we have to be very careful of using the sort of broad, single variable differences to then say, "Oh, obviously, this is a sign that Germany's energy policy is terrible." I'm not agreeing with a lot of German energy policy today, but I think we just ought to have a discussion that avoids making these sort of very, very broad comparisons. So that's the German thing.

On energy efficiency, I think that's a very, very important point. My sense is that there are some market mechanisms that exist now that begin to bring the demand side a little bit more into the equation. By and large, in the US, at least, it's much more command and control, where the utilities have, sometimes, big energy efficiency budgets. I think there is probably a fair amount of room for improvement. Since my big picture was about overall carbon emissions, my sense is that there is a significant amount of opportunity to further increase energy efficiency, probably cost effectively, with respect to traditional electricity consumption. I have looked at buildings a lot over the last couple of years. I think the ambitions and the rhetoric about how much progress we'll make on making our buildings more energy efficient is probably optimistic, given the observed rate of change in the actual energy consumption. We're here in a place that has buildings from the 1600s and 1700s.

Moderator: I don't think the HVAC systems are that old, though.

Respondent 2: No, but the building envelopes are pretty old, and they're really hard to upgrade. So one has to be a little realistic there, too.

Respondent 1: I think redeployment is an important issue.

Respondent 3: Isn't it the case that, with energy efficiency, the same regions of the country that are chasing these expensive clean energy standards are the ones that have taken a lot of the efficiency gains, and there are regions that have done very little, other than the national standards that the administration wants to get rid of? I mean, how do we get at the differential in start points?

Respondent 4: Yes, if you put up the energy efficiency resource standard map, it largely overlaps with the RPS map. I guess I would say, having studied energy efficiency a lot, that estimates of cost-effective savings based on engineering costs, things like the McKinsey curve, they have definitely shifted, because the price of electricity is cheaper now, or at least the avoided cost of generating is cheaper now, because natural gas is so much cheaper. So, your assessment of what's cost effective out there should probably change to reflect that.

I think a lot of analysis of how cost effective these policies are is kind of done before the fact. Right? And, of course, you want to make smart investments, so you do want to do some assessment before the fact, but I also think opportunities to really learn from what works and what doesn't work are often bypassed, and that, really, when economists go out and look at some of these programs, they find, often but not always, that the savings associated with particular investments are shy of what the engineering studies suggest. And some more information about that would be helpful, in terms of targeting efforts to get there through energy efficiency in an efficient way.

Respondent 5: On the demand side, if you look at the fourth graphic I put in, when you start to put a price on CO2, and when you feed back the retail price that reflects that to customers, one of the biggest things that you see in terms of a cost effective way to reduce CO2 is from the demand side. So, when you look at those points that I showed you, anything that's moving to the left is because of a cost-effective demand side option being implemented. But in doing that, the approach I took is fundamentally different from McKinsey. I think the McKinsey negative cost savings on efficiency is fundamentally in error. What you do see, though, is that prices have been very different, on a consistent basis, around the country. So, we do see a very reliable indicator of long-run price elasticity. Where electricity is more expensive, correcting for other factors, people will invest in more efficiency. And so that's what I've got in my feedback there, along with the fact that normally when the benefits of something are greater than the cost, we don't call that negative cost. We call it a profitable investment. And when it comes to investing in efficiency, it's got to compete with other profitable investments. If you force people to give you money to put into efficiency, you are foregoing other profitable things that they indicated to you they'd prefer to do. So, increasingly, efficiency beyond what people choose to do comes at a positive and increasing cost, not a negative cost.

Question 5: Hi, I wanted to follow up a little bit on a point raised in Question 1. A theme that's emerging, especially in the first presentation, but in a few of the presentations, is kind of this is really urgent, and, Speaker 1, you had the terrifying slide. And so, the idea is that we have to accept that we may need to do the third best thing that we can get done. And I guess what I'm thinking is, if it's really that urgent, and we want to avert the terrifying slide, then getting the US to a benchmark by 2050 is not the issue. It's getting the most worldwide emission reductions. And I guess the question is, if you think of it from that point of view, does that change the answer at all? I could see it might not. It could be that, you know, investing in renewables drives down the price, and that's all good. It could be that, really, if you think of it from a world point of view, we should do a less cost-effective for the US investment in nuclear and drive down that price, or we should think about world diversity of investment and let Germany do the renewables, and we'll do something else. Or we should adopt Martin Weitzman's proposal of a climate club, where you have a carbon tax, and then you have tariffs on people who don't. And I guess I just want to know if you have any comment on that?

Respondent 1: I can try. I'll start with the Marty Weitzman approach. I mean, I go back to the chart that I didn't show from somewhere in the late '70s. This was this IEA conference where all the attendant economists agreed that a carbon price is the obvious thing to do. And since then we've gone, you know, 35, 40 years, and the carbon price has pretty much been at zero the whole time. So, if the answer is already, "Oh, no, we've got to wait, we're going to hold out, we're going to do a global carbon scheme," I think I'm not very optimistic about that. I think, to the first questioner's point, I think the backlash question is relevant not just at the US level, but beyond. Maybe that's why the discussion gets so heated. Countries like Germany, the US for sure, other countries look to them, and they reach out actively to these other countries to follow their lead. So getting it at least not terribly wrong (I'm not going to say getting it right), but getting it so that there isn't this backlash, where you're looking back, and you go, "Oh, yeah, they spent a lot of money for ten years, and then they reverted back to the status quo," that is important. But I guess I'm not sure whether it changes the fundamental thing very much. It does sort of make it more important to balance feasibility with reducing of backlash domestically, and probably also having at least some minimum threshold requirement for being not terribly inefficient.

That's very vague, of course. "Avoid doing really terrible stuff" is a good rule of thumb, but I don't know whether it's sufficient to avoid backlash in the long run. So, I think there is a fair amount of learning amongst the countries that try this. And so, Speaker 4 mentioned that cap and trade systems have evolved to where they're not quite at the cap and trade with a floor and a cap, or the floor equals the cap kind of outcome, but there are no floors, and then there are ceilings, and cost containment mechanisms, so there is evolution. I think there is a fair amount of agreement on those elements. I think there is also some agreement that, over time, and as technologies mature more, you'll have to broaden the set of technologies that can participate, and whether that ultimately converges to something that's actually similar to what you'd get with a carbon price is a separate question. So I think, even though it's muddling through, focusing on those kinds of lessons, where it's a pretty broad agreement, as opposed to staying on the kind of the extremes, would be helpful for minimizing backlash and helping the rest of the world feel confident that they can align with those kinds of lessons.

Respondent 2: You know, this question of urgency comes up a lot, because there are a lot of people that believe that to achieve the long-term climate goal of Paris, you've got to reduce net anthropogenic emissions to zero by 2050. That comes from analysis that's built on a finite carbon budget analytical framework. And a finite carbon budget assumes there's no sustainable level of CO2 emissions. So, when I did this analysis, there was an estimate of the finite carbon budget available to the world to achieve the 1.5-degree target. And it was 400 billion metric tons from January 2011 forward. That was produced in the IPCC AR5 study. Now, the problem was, between 2011 and 2018, we spent 327 of the 400. So, with current emission rates of 42 gigatons a year, we were going to spend the budget within the next two years, and the global average surface temperature hasn't moved up to 1.5 degrees. So just last year, the end of last year, the IPCC released its 1.5 special study where they updated their estimate of the finite carbon budget. So now we've got a seven times higher carbon budget, from January 1st of this year, compared to what we had from the 2014 estimate.

There is a fundamental problem in the analysis, because it assumes there's no sustainable level of CO2 emissions. And just let me tell you what the current sustainable level of CO2 emissions are. So, in 2017, atmosphere concentrations of CO2 went up 2.3 parts per million. You get a one part per million increase for every 7.7 gigatons of CO2 that goes up and stays in the atmosphere. Which means, 18 gigatons went up and stayed in the atmosphere. Net anthropogenic CO2 emissions in 2017 were 43 gigatons. What happened to the other 23? They were absorbed by the increase in ocean and terrestrial carbon sinks in the carbon cycle, which is a function of CO2 concentrations in the atmosphere. So, if we currently could wave a wand and reduce our emissions to 23, we would stop the increase in atmospheric concentration of CO2, we'd stop global warming, and we'd be doing it before we're at 1.5 degrees C. So, there is a sustainable level. It is a function of this increase in sinks, and IPCC research says that in a 1.5 degree scenario, the most likely thing is that the sinks are going to continue to increase, although at a slower rate, so a finite carbon budget analysis is fundamentally at odds with a very clear part of the climate system that we expect to be in place in a 1.5 degree outcome. So, that is the basis for the kind of two ton per person by 2050 target, which is far more achievable than getting to zero.

Respondent 1: Can I respond to that very briefly? I think that's actually the wrong framework entirely. I mean, if my slide (which was stolen from the movie *2012*, incidentally), if that gives the impression that we know that this is going to happen if we don't get carbon emissions down to zero (which I didn't claim, by the way)…by 2050, the energy system probably needs to have zero emissions. We still have a bunch of other emissions, but that's the wrong framework. We don't know. Even though economists think they know a lot, they know nothing about climate systems, and the worst thing is that climate scientists don't know a whole lot about climate systems at this point. So, it's really a risk game we're playing, and, in some sense, the social cost of carbon might as well be a question about the willingness to pay to reduce the risk of something bad happening by a number of percentage points. So the fact that, for example, oceans absorbed a bunch of the emissions, that is true, but the pH level of the oceans is also dropping at a pretty significant rate, and the guys who study oceans have no idea what the pH level is where a bunch of stuff that lives in the oceans all of sudden dies. So, I think there are just unknown consequences of what we're doing that have a potentially very high damage function. And, therefore, our actions, in terms of how rapidly we do this should be, in my view, more determined by having an insurance approach to this than by, "Oh, here is our carbon budget, and if the carbon budget increases, let's slow down."

Respondent 3: Yeah, aside from all the carbon going into the ocean and killing the things in the ocean, it's limited sink. It's like a Coke, where, basically, when it's in the bottle, and it's pressurized, it basically keeps the CO2 in the water. If you open the Coke (the analogy there is to reducing atmospheric CO2 emissions), that carbon comes back out. Your Coke goes flat. The carbon is dissolved in the water, and it comes back out. It's not a long-term sink, if we're going to be reducing atmospheric CO2 emissions. It's s not a good thing the CO2 is going there. It's not a long-term sink. In fact, the long-term sinks are biological processes in the oceans and on the land that are in fact being killed by climate change and acidification. So, it's not a good thing.

Moderator: It's interesting that I'm here with all these experts who admit to uncertainty about this. And yesterday I testified in the House, where there was complete certainty on every aspect of this from people who are not studying it. [LAUGHTER]

Question 6: Following up on the earlier question, the big problem is not the US. It's the rest of the world, or, in particular, China and India, but perhaps even more importantly a whole lot of Southeast Asia, which is really hot, really muggy, and increasingly wealthy. And after they get their fridges, the next thing they're going to get is air conditioning, right? (Which California, except in the Central Valley, doesn't need.) So, what lessons do we have for these other places--again, contrasted with California, which doesn't have heavy air conditioning requirements? What lessons do we have for the rest of the world, if any, right, as we continue to fiddle around while the carbon burns? Do we have any lessons? Are we talking about completely US-centric stuff, in which case, in my opinion, we're basically wasting our time, if there are not serious coherent lessons for the rest of the world?

Respondent 1: I don't know if it's lessons, exactly. But I think leadership and examples, and not just by states, but by the federal government, could at least bring you credibly to the table with discussions with the rest of the world. So, I think we're missing some opportunities there, for sure. And it makes you part of the conversation, and then it's easier to share lessons, once you have them.

Respondent 2: I think the point about lessons is very important, because you have to realize that no single country can solve climate change for themselves, and so we need to have some examples for other people to follow, because we need a collective solution here, and it's very important to provide some examples. To your point, we do expect continued economic development, so that more and more of the world is going to be living modern lifestyles that include a lot of electricity consumption, and that's India and China, going forward. And so, you want to look around the world for a developed economy where people live a modern lifestyle that's fairly electric intensive, and you've got a good electricity/CO_2 per capita profile.

Now, there are a few. Iceland. Alright, if you live on top of a volcano, you've got a lot of geothermal. Alright? That's not a lesson other people can follow. So, what developed country lessons could other people follow, countries that are where you need to be in the long run? France, Ontario, developed economies. What do you have? You have some good hydro, a large dose of nuclear, renewables backed up by natural gas-fired generation. It's the kind of mix that I showed you in graphic number four. So, there are examples to follow. And that's what it kind of looks like out there. The mistake most people make is to look at politically defined areas, like Denmark. They say, "Well, look at Denmark. They're getting 80% [from renewables]." But Denmark's part of a much bigger grid. It couldn't do what it does, if it weren't part of the bigger grid, so you've got to look at the big grid kind of story and come up with examples that make sense.

Respondent 3: I agree that you have to be careful when you take the virtuous Denmark as an example with respect to all the things they have done. This is not electricity market related, so much, but there are some countries like Denmark or Sweden, probably Holland now, in Europe. They're small. They're integrated. They have a bunch of woods, or powerlines that go to Norway, and all sorts of benefits. But I think, as societies, they have committed to spending some of the wealth that they have to make big changes to how they run their energy systems. So, Holland has basically stopped, for natural gas. And it's thinking about converting its heating infrastructure to something else. Those things are not free for those societies. My sense is that that kind of leadership is actually something that some of the developing countries will look to when they make their own tradeoffs between air conditioning their economies and how rapidly they do that and how fossil intensively they will do that.

Question 7: In a couple of weeks, each of us in our very own special ways will celebrate the ten-year anniversary of the Waxman-Markey bill actually passing the House. I was in law school at the time and thought I was going to be a cap and trade lawyer for the rest of my career. But that's an example of enormous backlash. And in that case, it was a cap and trade policy. It wasn't perfect. But, you know, it was generally the sort of thing that economists like, and it didn't matter. Right? I mean, there was still tremendous political backlash there. And so, my point is just that, no matter what you do, in the political environment that we're in today, there's going to be enormous backlash.

I don't think that should be an overriding concern. I agree with Speaker 1. Let's just avoid doing the worst possible things. But even if we do the best things, in today's environment, there's still backlash. One thing that maybe has changed in the past ten years, and this is in part due to all these imperfect policies, is that we increasingly have more experience with things like renewable energy. We have giant industries now who can be sophisticated political players. We have rural parts of the country that have seen the benefits of this, and so maybe that's part of switching the political dynamics, with all of these policies combining to have those effects.

Question 8: That was actually a nice lead in to my question. I'm going to start by maybe characterizing where I feel like the panel is coming out. So, my sense is that everyone would probably agree that if you were king, and you could design the policy, some kind of market-based cap and trade approach would work. Where the panel seems to differ is in terms of those second-best policies--how much they are second best, and the extent to which we are off on the wrong path by following them. And my guess is, everyone could characterize it that way. I've typically been much more in Speaker 3's camp about this, believing that if we're going to solve this in the long run, we need to be heading towards a real market-based policy, either cap and trade or a tax. But I have to acknowledge, as the last questioner said, that we've had 20 or 30 years experience trying to do this, and we need to acknowledge political realities. And I think Emmanuel Macron would certainly agree that putting taxes and costs on energy has severe political consequences and very fast backlash, potentially. I was in Oregon recently, talking with legislators worried about a 16-cent increase in gasoline prices and the backlash they were getting from people locally about this.

Also, recognizing that when we do a particular policy, a subsidy, we create a constituency for that subsidy, and once it's created, it's really hard to undo. And I've seen that with renewable fuels policies, where we now have an industry basically dependent on them.

And so, there are a lot of tradeoffs here from the political economy standpoint. But from that point, I want to introduce a potential idea. Most of the discussion's been about either/or. And one thing I've been thinking about, and others have, is about transitioning. And, you know, the reality is that if by 2050, we think we need to have a really strong market signal and that we don't want the energy policy and the climate policy to be dependent on the political system to pick the right policies and subsidies, and we want to be there with a strong policy, whether it be $50 or $180, but that that's not politically feasible now.

And if we think about implementing a combination of approaches, thinking about the transition path between policies, I want to ask whether or not that's an idea that might help us think about getting there in the long run, but doing some politically practical steps in the short run to get there. I'm just interested in the panelists' thought about whether or not that time dimension and changing policy over time is something we should be adding to the conversation, instead of it just being an either/or.

Respondent 1: I think that's absolutely right. This isn't going to be sequential kind of decision. It's an evolutionary thing. We're going to be refining these policies as time goes along. And, I mean, just looking at the last ten to 15 years, the cost of carbon implicit in our carbon policy now would have been higher if we hadn't have done the pro-renewable policies that we did. We drastically drove down the cost of wind and solar, and it has made it more politically and economically viable to do a pure carbon price, or something like that. And so, I think things will continue to evolve, and, again, I think that's further argument for why we should continue to drive clean energy deployment, using the second-best policies that we can do now. That, I think, helps in the long term in bringing the cost down, but also demonstrating that, hey, this isn't so bad. The cost isn't so high. I think it makes the long-term goal of a carbon price more achievable.

Respondent 2: At the risk of being presumptuous about what I know about California, I do work in an office next to somebody who's very involved with that program. And he tells me that Mary Nichols has said that in California, this evolution is happening. They have the AB32 cap and trade program, but they also have all these other initiatives, and that they're shifting more to having the price do more of their work in terms of reducing emissions. So, that's part of that story as well.

Respondent 3: On political feasibility, I think it's pretty clear that in developed countries, including the United States, the majority of people want to do something about climate change. And I think it's a very strong motivation, because people are afraid of the consequences down the road, and they feel guilty about the energy-intensive lifestyles that they lead. So, fear and guilt are very strong motivators to get something done politically. I think the problem with feasibility is, we've got too many people telling them, with these simple levelized cost assessments, that it's cheap and easy, and you've got negative cost efficiency, and that we can get there with command and control, instead of educating people that California isn't working well. These approaches are not working well. If we keep doing them, we're going to have ineffective climate policy with political backlash, and we're never going to get it done. And as long as we keep making believe that this stuff is working OK, we're never going to get to the right solution, even though I think there's very strong political motivation to get something done.

Question 9: So, this is a conversation that's been changing quite quickly. And I guess my broad question, before I go into a bit of a soliloquy here, is, how do we stay focused on the "no regret" moves that support systemic change?

So, in a lot of the conversation that I'm hearing, there's a lot of fear of the unknown, and it really boils down to what we hold as sacred and how we're tapping into the human ingenuity that's available to us. We've talked about backlash effects and stranded costs and unintended consequences and all of that. But the flip side of it is, while we have path dependencies and inertias, our assumptions are outdated, and in some ways that constrains the way that we're thinking about this problem. And, clearly, there's a need to make a leap of faith. Right? For example, Speaker 3, you clearly don't want things to change, and I think that's a very common sentiment amongst a lot of people in our society, but, really, what is the leap of faith that we need to make? And how important is it?

So, we're talking about the social cost of carbon, which really comes down to what we can measure and how we model uncertainties and, ultimately, what we value as a society. And, for example, we're not thinking about the value of biodiversity, because we don't fully understand it. And we tend to trivialize the real cost of mitigating ecological collapse. We talked about how oceans are a carbon sink, but, really, they're in danger, and what happens if we lose our oceans? I mean, it sounds silly, but what happens if we lose bees? [LAUGHTER] And we tend to trivialize those things. And the impacts of climate change, they turn out to be worse than expected, because things are inherently nonlinear. And we tend to think more in the linear terms. But that also applies to human ingenuity.

So, while climate change turns out to be worse than we thought, new technologies have been overdelivering, and the types of costs that we're seeing and the types of new performance characteristics that we're seeing are simply beyond what we could have imagined even a short time ago. We tend to look at simple metrics in isolation. We talked about how LCOE is too simple a metric. But we also tend to look at things, all else equal. Right? So, the cost of solar is less than the cost of gas, and this and that. When we look at one of these metrics, we're not looking at systemic change, but new technologies really are changing the way that we're operating the system and the types of investments that we're making. And some of these investments are beneficial in all scenarios.

I'll take the example of advanced transmission technology. So, ARPA-E funded some really exciting technologies that are commercially ready, and the technical risk is pretty much retired. But we're still not adopting it. And if you combine that with demand side management and storage and all these other great things that we have, I mean, suddenly we're improving economic efficiency and reliability, and we're getting really good options for the future, whether it's a future that's 100% renewable or something else.

So, back to my initial question. How do we carve out the space to tap fully into this human ingenuity, even if that means that we need to make a leap of faith? What areas of consensus can we tap into? For example, around a value of advanced transmission technologies, or shoring up our networks, so then we can accommodate more resources, curtail less, and have better economic efficiency and reliability?

Comment: And I'll just chime in that, based on yesterday, innovation is the new Republican word for fighting climate change. That's the new word.

Respondent 1: I'll try a little bit of that. So, in spite of the discussion we've had about Germany, the Secretary of Energy in charge of the energy transition was, until recently, Rainer Baake. He was a pretty smart guy. The way he framed what Germany is doing is, "We're setting an ambitious target. And we know kind of where this goes through 2030, maybe 2035. And beyond that we have no idea how this works, but by setting sort of clear targets and mandates, we count on market players and R&D players to figure it out." So, I would go back to saying, "Well, I would spend a lot more money on R&D as part of this to sort of get the ARPA-E stuff, maybe multiplied by five or ten." On the flip side, I would not count on the solution coming out of the R&D program that we're starting now, because I do think that there is more urgency to this. You mentioned the "no regrets" approach. I think that's a risky strategy, to only make investments that we know we're not going to regret. I suspect that for some of the massive societal transformations that have happened over, whatever, the last 200 years, like the interstate highway system…we have to at least be willing to create some stranded costs, because it will maintain the option to actually meet our goals, to minimize the risks of catastrophic climate change, in case that our increased R&D funding does not deliver the solution that we need.

Respondent 2: Your comments tend to suggest that we're making some progress and that we ought to keep it up. There's some data that kind of gets in the way of that, which is, when you look globally, net anthropogenic CO_2 emissions continue to march up pretty much unabated. Last year in the United States, the CO_2 emissions from the electricity power sector went up. I don't know if most people know that. So, I don't think we're making a whole lot of progress against where we've got to get and how fast we've got to get there.

And when you talk about all of the great advances we've made in wind and solar because of mandates and subsidies, by not putting an appropriate price on CO_2, we haven't seen innovation and investment targeted to other things that maybe have better prospects for making a dent in the future, because we've already picked what we think are the winning technologies. And so, I think this goes back to a basic problem in this whole idea of what to do about climate change, which goes to Daniel Kahneman, who won the 2002 Nobel Prize for economics, but he was a psychologist. And he analyzed behavioral economics, and tells us that our human nature gives us a bias to optimism. And what I'm afraid of is, instead of dealing with the real data and what we're learning right now about reducing CO2 as far and as fast as it needs to go, instead of facing that basic reality and doing something that makes sense, we are embracing these technologically optimistic scenarios of the future. We're going to invest in batteries. We're going to have load follow supply. We're going to plug our cars in and have the charging. And it's just not happening. So, at a minimum, those technology advances, we're way out ahead of them right now. They're lagging. And it may reflect this technological optimism that we glom onto because we're unwilling to face what our experience is telling us right now.

Session Two. Volumetric Residential Rates: Socially Progressive or Regressive?

While the costs incurred in serving residential load are fixed, demand, and variable in nature, the prices charged are disproportionately volumetric in character. That disconnect between how costs are incurred and how they are passed on to consumers distorts price signals to users and incentives for utilities. Volumetric pricing presents a disincentive to utilities to help customers be more efficient in their use of energy. Decoupling was supposed to be a remedy. While decoupling may or may not ameliorate the adverse impact on conservation, it does little to create a better nexus between costs and prices. While those defects in volumetric pricing have been known for some time, little has been done to reform that basic flaw in retail residential tariffs. One of the reasons for resistance to reform has been concerns about the impact on low income consumers. Are cost reflective and fixed cost charges socially regressive? Is it possible that, in fact, appropriate fixed cost-based prices are more progressive in impact than volumetric tariffs? Even assuming, for the sake of argument, that volumetric pricing is less regressive than the alternative, is it justifiable to structure all residential rates on that basis? Are there not more efficient ways to protect low income customers than to distort all residential rates in ways that do not reflect costs?

Moderator.
"Volumetric residential ratees: Are they socially progressive or are they regressive?" It's going to be a very interesting afternoon.

So, I'm going to take the moderator's privilege of just taking a couple minutes to set out three or four questions that I have that I hope will be addressed this afternoon. The usual ground rules apply, and one more, and that is that we're not going to debate the merits of whether there should be a low-income subsidy or not. We're going to assume that, in order to get to the rate design issues.

So, given that, one question I have is, if, in the real world, you have to choose between what you may see as inefficiency, a distortion in either the fixed price or variable price of electricity, which one would you choose? And why? Related to that, why do we have this fixed versus variable debate in the first place? (Mostly in regulated industries, at least so it seems to me.) The third question, as long as we're in the theoretical phase, is, in the very long run, aren't all costs variable? And where do you draw the line between fixed and variable? And how would you do that? So, with that, we'll start.

Speaker 1.
I'm going to talk about some of the research happening at the MIT Energy Initiative on the distributional impacts of electricity rate design and try and touch on the benefits of getting it right, and also some of the costs of getting it wrong. Some of this is probably going to be very familiar to all the people in the room, given that this is an expert audience, but hopefully there'll be some new insights here as well.

So, one question is, do fixed charges harm low-income customers? I'm going to give you a preview of the answer. The distributional outcomes of rate design are really kind of a design choice, and so we show a number of different ways that you can design rates to prevent or mitigate undesirable distributional outcomes. And I guess efficiency and bad distributional outcomes are not synonymous. The second is kind of, what's the cost of an action? Well, there's a lot of research on this, so I don't need to touch on this for very long, but efficient rates hold the potential to create a lot of consumer surplus and reduce cost dramatically in the long run. And, additionally, something that I think may be not talked about as often as it should be, we're now in a world where you can think of consumers as pushing back, and so the cost of inaction is no longer that we're foregoing some benefit; we could actually be driving additional costs, if consumers are inefficiently deciding to bypass grid-based electricity services in favor of services that maybe appear to be more economically efficient for them, but really they're just shifting costs between customers. And there's some evidence that says, at certain levels of rooftop solar penetration, that the rates that we have today, these predominately flat volumetric, or time invariant volumetric rates might be worse for lower income customers than alternatives.

So, the first question, do fixed charges harm low income customers? In order to get at this, we started with a dataset of about 100,000 customers in the Chicago, Illinois area. This is half-hourly metered data. And at the individual customer level, we had data as well on the housing type and the type of heating, and then we had these customers identified by their nine-digit zip code, at the geographic level. So, obviously, all the results that I'm going to be talking about are within the context of the specific numbers, and the results I'm going to be talking about are within the context of the Commonwealth Edison geography. But I think that some of the key takeaways you can think about translating to other geographies as well. So, basically, what we did is we built a model of the cost of service for these customers from regulatory filings from Com Ed and from the load data that we had from Com Ed, and we broke that out by different distribution costs, transmission costs, energy costs, metering costs, and then what we called "policy and other costs." This is the cost of programs like energy efficiency programs, or environmental remediation, and other things like that. And then we looked at a number of different ways to allocate those costs.

So, the flat rate, where the energy price doesn't really change with time or location and recovers more or less all of the costs through a dollar per kilowatt hour charge, is the default rate in Com Ed. And we also looked at time of use prices, critical peak prices, real time prices, demand charges, fixed charges…the different ways of allocating and recovering these costs. To understand some of the distributional outcomes, we paired this meter data with census data at the census block group level. And we looked at a number of different socioeconomic variables, including, primarily, income. We broke things down by nine different income classes. The census reports something like 20, but we found that cumbersome. And then we also looked at a number of other socioeconomic variables, like race, unemployment status, education, *et cetera*. I'm going to talk mainly about income here, but you can see that our paper that talks more about some of these other variables.

So, what's the punchline? This graph might be a little bit hard to see, given the lighting, but let's imagine you took today's flat volumetric rate, where you're recovering most of your network costs through a dollar per kilowatt hour charge. If you said, "OK, we're going to reduce that dollar per kilowatt hour charge, increase the fixed charge in order to remain revenue neutral, and we're going to recover all of our transmission, distribution and policy costs." If you did that, and you kept the same fixed charge for all customers, you get this kind of slanty line that you see here in the middle. So, the low-income customers end up seeing, on average, a bill increase, and it's actually (this is in absolute terms) about $30 per year, which doesn't sound that huge, but in percentage terms it's actually relatively significant for a lot of low-income customers. I'll talk about different ways to design that fixed charge in a second. So, let's say all you wanted to do is recover all of your costs, and you designed a fixed charge that was the same for all customers. In the Com Ed service territory this is likely going to increase costs, on average, for low-income customers. And there's pretty good reason to believe that finding will probably hold true in other parts of the country. If you look at the EIA's RECS data, the Residential Energy Consumption Survey, it shows, pretty much across the board in the United States, that low income customers tend to consume less, on average, than their more affluent counterparts. So, this finding is pretty consistent with other findings in literature. What we found is, if you then took the energy price and said, "OK, right now we're charging an energy price that kind of represents the average dollar per kilowatt hour charge for energy throughout the year, and you restructured that to actually reflect the real time price of energy, at least in this case it doesn't seem to have a significant, or possibly a slightly positive, impact for low-income customers. And I think the logic here, in this case, is that, generally, a lot of the consumer technologies that are driving those peak demands, things like air conditioning and other appliances, are less common for lower income customers. So, the things that are driving peak demands and those peak prices, low income customers tend to have fewer of those technologies. Given that peak demand or demand charges also tend to track total consumption reasonably well, we saw a trading off between volumetric charges and demand charges, and demand charges, at least in this case, had kind of a negligible impact on low-income customer bills, on average. And in each of these income categories, there's a distribution of outcomes. Some customers in the lowest income bracket tend to benefit from these changes, while some customers in the lowest income bracket are harmed from these changes. But, on average, these are the impacts that we saw.

I think the general takeaway, in terms of the recovery of what we call residual network costs, or fixed costs associated with transmission and distribution networks, and maybe the costs of policies that are in place that you can't economically efficiently recover through short run marginal costs (we call those "residual costs"), and maybe this word is scary to a lot of people, but recovering those costs looks a lot like taxation. So, these are costs associated with running the power system that need to be recovered, but that can't be recovered, and can't be attributed to any one individual's short-run actions.

So, the punchline, I guess, is that the economics literature says there are a lot of efficient ways that you could recover these, as long as you're not incentivizing people to jump off the system. So, if I set your fixed charge too high and you're incentivized to disconnect from the system, we don't want that. But as long as we're not doing that, there's actually a lot of leeway in terms of the per customer charge that can be considered economically efficient. So, we said, "OK. Well, given that we have a lot of flexibility with how we design these charges from an economic perspective, can we keep all of these economic efficiency benefits that we get from moving to charges that more accurately reflect the short-run marginal cost of energy and aren't embedding all these distortions associated with recovering fixed distribution network and transmission network and policy costs in a per kilowatt hour manner? Can we keep those efficiency benefits while mitigating some of the undesirable distribution outcomes that we just saw?"

We explored a number of different ways, and I'm going to show two proposals. I guess the basic takeaway is, yes, and all you've got to do is not charge everyone the same fixed charge. It's a pretty groundbreaking idea. So, we said, "OK. Are there multiple ways to do this? We looked at changing the fixed charged based on observable customer demand characteristics or imagining a world in which the utility could actually observe income, and just based the fixed charges on income. And we talked to utilities. They have Experian data on their customers. They know what the incomes, more or less, of their customers are. So, while this isn't something that is done today, it's something I think utilities probably could do if this was something deemed regulatorily desirable.

So, we basically looked at the correlation of different customer demand characteristics with income. And we found that there are a number of demand characteristics that correlated more strongly with income than did total consumption. Peak coincident demand correlated more strongly with income than did average consumption. And then I think which demand characteristics correlate more strongly with income is going to change, depending on where you are. It might look different in Texas than it does in Chicago. But our hypothesis is that, likely, in different parts of the country, some of these demand variables are going to correlate strongly with income. So, one idea would be to look back at a customer's historical demand profile and say, "OK, their peak demand over the last five or 10 years was X. We're going to design a fixed charged based on that." So, we modeled that, and that's the orange line that you see now slanting upwards as you move from left to right. Basically, what we saw, is that, if you designed a fixed charge based on a customer's historical peak demand, then it tended to be much more progressive than the alternative. And so, you actually saw a benefit, and that benefit, on average, from moving from these inefficient flat volumetric rates to more efficient rates for low income customers.

There are obviously pros and cons of this type of method. One pro is that it's feasible. You could design these rates with existing data. You don't need to look at things that utilities today don't tend to look at. You don't need to look at customer income. You can design this directly on the data that you have. The potential drawback is that you have Type One and Type Two errors. So, for some low-income customers that have, for whatever reasons, some peaky demand, you charge them a high fixed charge, and that could be negative. And, similarly, there might be some higher-income customers that have hyper-efficient homes, and, as a result, you maybe charge them lower than you may like. And I guess one of the other drawbacks is, if you're changing these fixed charges frequently, they start to look like demand charges, and you can get some of the same inefficient incentives that you would with a flat volumetric tariff. So, if I knew that if I reduced my peak demand this year, my fixed charge would be lower next year, that's not really a fixed charge. So, that's something you want to avoid.

We also looked at designing fixed charges directly based on income. And one of the things we toyed around with was changing the ratio of a low-income customer's fixed charge to a high-income customer's fixed charge. So, if you wanted to transition from today's tariffs to this new tariff, and you had access to income data, and you could design personalized fixed charges, you could say, "We're going to design the fixed charge such that no low-income customer sees a bill change more than 10 percent," and that's achievable. We also looked at other types of protections. So, imagine that a customer was expected to see a bill increase under the tariff change, you could then basically hedge that customer against any bill increases. And this is a program that's been implemented in certain parts of the country. In California, for example, for commercial and industrial customers, when they moved to critical peak pricing, they said, "Listen, if you're bill is going to increase under the critical peak pricing, or if at the end of the year your bill increases under critical peak pricing, you can default to go under the bill that you would have had." And, actually, if you implement that, because you're now not subsidizing every single low-income customer, but only the low-income customers that would be worse off under this program, then the rate impacts on other customers is tiny. So, the change in bills for non-low-income customers as you implement this program is a really minor impact.

So, I'm going to really, really briefly run through the cost of inaction. Efficient rate designs can really drive a lot of consumer surplus benefits. Even under uniform fixed charges, a little over 70 percent of low-income customers actually see benefits from these programs. And then, obviously, as income rises, they see larger and larger consumer surplus benefits. And so, the net benefit for consumers was about $40 million per year on the subset that we saw, which is a pretty substantial benefit. But I would also argue, again, that as distributed energy resources proliferate, one of the potential costs is actually incurring undue harm on low income customers as a result of inefficient DER adoption. So, if you look at the income trends of DER adoption, one thing is very clear over time, and that's that higher-income customers tend to kind of take the lion's share of solar PV adoption. And that's what this chart shows. And so, we basically simulated PV adoption under these conditions, and as solar PV penetration amongst single family homes increases, bills, on average, increase for low-income customers and decrease for higher-income customers, due to the cost shift of network costs. So, with that, I'll wrap it up and look forward to the discussion.

Speaker 2.

I thought you were going to put the three-minute thing in front of me right now. [LAUGHTER] Anyway, thank you very much for the invitation to be here. These are always a lot of fun and interesting.

So, with respect to fixed charge rate design generally, I would just start off by saying that, as low-income law and policy advocates, in general we don't look kindly on this rate design, and view it as a regressive for the reasons that Speaker 1 alluded to earlier. Rate design is a zero-sum game, and we know that transferring cost recovery from the volumetric portion of the bill to the fixed portion of the bill will shift costs to low volume consumers within a customer class. That intra-class cost shift is what we're concerned about. And I've got a little bit of data here. The Energy Information Administration's 2015 Residential Energy Consumption Survey allows the user to look at electricity usage by income category. And when you do that for each of these census regions in the United States, generally, throughout the country, we see that the poorer you are, the less you use. And, to back up just a little bit, I think it's important to emphasize that the correlations here are not as strong as you might think, just looking at these curves. There are an awful lot of outliers in every income category. There are high users who are very poor, and vice versa, but this is taking a look at median consumption. So, it's about counting the winners and losers. And what this tells us is that there are more losers on the low-income side when you shift that cost recovery to the fixed charge than there are for the higher-income counterparts. In 2009 the Residential Energy Consumption Survey was a little more robust, and the sample size was pretty good, and you could break the analysis down geographically by 27 or 28 of what EIA called reportable domains. Some are single states, some are two or three states, but it's more granular than census regions or divisions. And there were also poverty flags. In this case, I used a 150 percent poverty flag that was part of that survey to really show the same results, and I find that this data is important, because in the interventions I'm involved with, utilities often argue that, "Well, no, our low-income customers are high users. They use more on average." What happens is, I think, the companies tend to base that assumption on their identified low-income customers who participate in either low-income energy efficiency programs or bill assistance programs. And they tend to be more skewed toward homeowners, higher users. Folks who get referred to these programs, in many states, have higher arrearages and high bills. So, the total universe of low-income households and those that participate in these programs is different. And this chart helps to show that in virtually each of these geographic areas the relationship between median usage and income exists. There's one outlier here. It's Idaho, Montana, Utah and Wyoming, and why that is, one can speculate, and we don't have time to get into it, but for all the other reportable domains we see folks below 150 percent of poverty using less electricity, on average. The National Consumer Law Center (NCLC) has a website, if you want some documentation and some analysis of each of those reportable domains by race, by age of householder… It's all there. There's an interactive map you can click and get the fact sheets.

So, what's the other side of this? We know low income households use less electricity, but it's also true with gas and other heating fuels. They're using less, but they're spending a much larger proportion of income just to stay connected to service. And, start with the assumption that home energy service is a basic necessity of life, without which you can't really participate effectively, and the health and safety ramifications, in this country, anyway, of losing that service run pretty deep. So, we see a regressivity in these energy burdens in terms of the cost of the system. The RECS also have information on other measures of home energy security. One of them is the frequency of foregoing necessities in order to pay a bill. Folks at the lower end of the income scale, many have chronic problems with having to forego other necessities just to stay connected to electric or home energy service, and when you look at households under $40,000, the real chronic problems and the problems for those who, reportedly, some months have to forego necessities. It's a lot of households. And so, even though we love to talk about pure economic regulation, these are public policy matters that can be addressed in rate design and regulatory decision making. And they should be. And, in terms of opinion, those who say, "Well, we're talking about economic regulation, and that's what we do at the state level, and that's what utility pricing is all about," I just don't buy that. There are all kinds of public policy considerations that are baked into rates, and I would also add that the regressivity of the distribution of costs and benefits is baked into our system in a way such that to not address those issues is really not justifiable, in my opinion.

There's a racial justice aspect associated with this regressivity as well, again with this metric of foregoing necessities. And some of the other metrics measured in the RECS are unhealthy home temperatures, receiving a disconnection bill, and loss of service. But, with this one, we see disparities by race. Maybe this isn't surprising, given the income disparities by race that we see. But I would suggest that even when one controls for income and looks only at households with income under $40,000, you still see racial disparities in foregoing necessities and loss of service, and in some regions of the country more so than others.

But anyway, this movement towards fixed charge rate design, this is a prevalent proposal we're seeing from utilities in rate cases. There is a rash of these proposals and, to get to one of the moderator's questions, this is happening, presumably, because the rate of increase in utility sales has really fallen off the cliff. There used to be four or five percent growth per year in the electric utility sector between the post-World War II era and all the way through the 1980s and 90s. And in the most recent great recession, we saw that sales growth rate really level off, and it's pretty much flat now. So, without getting into a discussion of revenue decoupling, you see that perhaps there's a concern that utilities are taking on sales risks through volumetric pricing, and they want to mitigate that, and thus the movement toward these fixed charge increases. At least that's one explanation.

We talked a little bit about the intra-class cost shift that this entails, and I'm going to skip over that. But, for our clients in particular, control of that home energy bill through energy efficiency measures, or perhaps other modifications, that's critical. And if you have an overemphasis on fixed charges, and your bill is high before you flip the switch, it can really be devastating. A lot of companies, rather than propose a massive fixed charge increase, are coming in more frequently for rate cases and proposing small ones.

I want to say a couple of things quickly about advanced metering and low-income customers and rate design. There are three categories of concerns with respect to AMI and time-varying rates for low-income advocates and their clients. These systems are very expensive, and they need to be paid for. The business case associated with rolling out these systems now for the about 45 percent of residential customers that don't have AMI is increasingly difficult to make. And without the American Recovery Act subsidies and others, the business case has hit some roadblocks. But that certainly is a concern for advocates. Who's going to pay for these systems?

Remote disconnect and reconnect capabilities. We see, in many jurisdictions, increases in the number of disconnections for nonpayment when these systems are rolled out. Prepay is another concern. We don't have time to get into that right now, though. And then there can be penalties from time-varying rates.

So, basically, I think you can mitigate some of these concerns. We're not in a "just say no to smart meters" position, but we are very skeptical. But there are means to mitigate each of these concerns.

I only have one minute, so I'll go to the concerns with respect to time-varying rates. We can have "hold harmless" provisions, where low-income customers are by default placed on the most advantageous rate and there are some other measures with mitigation potential. I want to allude, in the last 30 seconds I've got, to a mitigation measure that we see applied in Massachusetts that pertains to net metering. And the reason I'm raising this is that we can argue about these technologies and rate designs all we want, but in many cases there really is a mitigation option available. Now, net metering and the cost of the SRECs in Massachusetts have resulted in real bill impacts for all customers. It's significant. Well, in Massachusetts, a lawyer, the name of whom I'm forgetting right now, but someone who I do know, was involved in getting a statute adopted that requires any net metering and SRECs costs to be reflected in an adjustment to the low-income discount here in Massachusetts. And how he saw this, 10 years before solar panels started getting cheap, I don't know. But we've got that in statute.

Real quickly, with respect to variable fixed charges, I believe, subject to check, that at Nevada Power there's a two-tiered customer charge. For multi-family housing, it's about a third to a half of what it is for single-family housing on the residential side. This stuff isn't rocket science, folks. We can work it out.

Speaker 3.

Thank you for inviting me. I appreciate being here. I wanted to talk about a couple of things, briefly, in terms of some of the experiences that we've had, and just put it in the context of how I ended up on this panel. My company had done a lot of energy efficiency programs, originally, when we started the company 10 years ago. And then, about five years ago, we started getting access to AMI meter data, and in the process we realized that the energy efficiency programs were not producing the savings that were being assumed by the various manuals. And, in fact, the savings were so small that we abandoned all the energy efficiency programs. And that applied to most demand-side programs including load control programs and water heater programs that were mentioned earlier.

Anyway, we were sorely disappointed by the performance of these programs, once we got our hands on the meter data, and, as we started analyzing the data, we ended up in the software business. So, I'll just run through some of those experiences and put some context around them in terms of the economics of the business here, particularly in Massachusetts, since we're here, but this also applies elsewhere.

A couple of caveats. One is that we know a lot about AMI meter data and the economic analysis of that data. We're not experts on low-income customers. We have a customer that has over 100,000 low-income customers. We understand that those nuances are a significant and real expertise is required there. So, I don't have any wisdom to offer in terms of how to serve low income customers as well. But let's hope that at least some of the data will be helpful here.

Daniel Kahneman was mentioned earlier. Here's another reference. I'm paraphrasing, but he could have just said, in a tweet, "People don't make rational decisions. They rationalize their decisions." But I don't think you get Nobel Prizes for that, so he had to write a book. [LAUGHTER] But it's interesting how it applies to our business, because there's the obvious correlation, stating the most obvious thing. If you have bad inputs into decisions, you'll get bad decisions out of those inputs. Well, then the question becomes, what's the quality of the inputs that we have into the regulated decisions and our business decisions in the utility space?

So, what do we know about this? And here's a telling sign. When you go to a hearing, or you go to a meeting at a utility, or you go to anything that is being debated, you'll notice quickly that people argue positions. They don't argue evidence. And, in fact, there's a distinct lack of evidence in a lot of those conversations. So, we hear a lot of unsupported assumptions and a lot of rationalization, especially when things don't work. When things don't work, we hear people rationalizing the heck out of everything, particularly on the energy efficiency side and in a lot of other segments where significant dollars are being spent. But it's been interesting to us. We're basically saying, "We're not trying to argue a position ourselves. We're trying to show, here's what the data shows to us. You can draw your own conclusions from it." So, we get invited into these debates, either by the utility or in some other context, to basically say, what does the data tell us? Let's debate the data after that. So, you end up with this. MSU. Make Stuff Up (although the S is usually not "stuff"). This is what we have a lot in these meetings. People just argue over things without having any factual basis whatsoever for them. And often both sides are wrong. We're looking at the data, saying, "We have no evidence to support either side of this debate." And then we end up in a better place, once we actually discuss the data.

So, let me actually jump to that, for the sake of time. On the left-hand side of the slide, you'll see what people assume a customer looks like. On the right-hand side, you'll see what one particular utility's load shape actually looks like at a residential level. It looks very different. And, if you're in California, that's the big duck curve--actual load shapes from utility to utility vary greatly. But that's not the really interesting part. This is the interesting part to me. This is an actual customer. This is one week of a customer. Each color represents one weekday, 24 hours in a weekday. So, the horizontal axis is the 24 hours. Customer energy use is incredibly volatile. I mean, just dauntingly volatile. And you'll find that that is true for low-income customers just as well as it is for high-income customers. So, we basically come to the conclusion that there's not residential class at all. By inference, there is no low-income class.

A couple other data points to throw in there and to keep the economics still in the picture. We've seen the peak shift from the mid-afternoon until later in the afternoon in New England and in a lot of different states, as well. So, as a result, for example, for residential customers in New England, their relative share of the cost of the capacity increases, because commercial consumption is going down during that time period, whereas residential consumption is actually going up. So, you have sort of a relative share/allocation of cost problem for rates. But that's not the really interesting part. In Massachusetts, capacity costs went from 50 bucks per kW a year to about 150 bucks per kW a year. And if that seems like it matters, it's because it matters. That means that there was a $500 million value shift from the consumers to the generators in two years. So, that is one heck of a change to the economics of the business. And you don't hardly ever hear the New England utilities discussing this. We hear this a lot on the municipal utilities side, because they have to worry about capacity cost. They have to worry about the total cost. On the investor owned side, utilities often say, "We don't care about it. It's a pass-through," and then move on. But the customers ultimately pay for that. And so, how this reflects on the rates and the rate design makes it much, much more complicated, much more difficult, and I'll argue in a minute that it basically makes just getting the fixed/variable ratios and those kinds of metrics right hard enough, let alone trying to actually come up with a low-income rate on top of it.

So, one other metric. This past year, one capacity hour cost more than the rest of the year's marginal electricity put together. Let me say that again. One hour was more expensive than buying the electricity for the rest of the year, on an incremental basis—buying the next incremental kilowatt hour. And this is also true in the Midwest, where, for a bunch of utilities, over half of their procurement cost is now capacity cost. So, these things matter, and they have really upended the business a lot.

So, we went through meter data. We have data on millions of meters and from lots of different utilities, so we said, "What do we know about this stuff?" We have some rights to meter data. We actually licensed that data, because there's a lack of availability of AMI meter data. So, we've been able to look at identifying some patterns. So, again, the only thing we really determined from it was that customers are incredibly variable. In the Midwest, they look different than in the Boston area. So, here's an example of one particular utility. Single families use 9400 kilowatt hours a year. Condo's use 6800 kilowatt hours a year. Then you have two family homes, at about 5,000 kWh, and three family housing at 4,000 kWh. Not particularly surprising. Then we looked at the low-income households, and we just picked two separate apartment buildings, one of them modern, that has gas heating. That had only 3500 kilowatt hours of consumption a year. The other one was a 40-year-old building, and they have electric heating in there and central A/C also. That one used 7600 kilowatt hours.

So, everywhere we look, we just basically say, these customers look incredibly different. It depends on the circumstances of those customers. I don't know what a "low-income customer" looks like. I just don't know. They're so different. There are parts of the country where we see low income customers using incredibly little electricity. And we have one neighborhood where the average income is $30,000. There is not a lot of electricity consumption. But there are some houses that use 15,000 kilowatt hours a year. So, the energy use patterns are really variable. So, when we ask what an average low-income customer looks like, I don't think there is such a thing.

So, here's just a visualization of a peak day at this particular utility. The blue line here is the low-income households. But the variability, even within that apartment complex, the variability among users is astoundingly high. So, how do you design rates for that? What is a fair rate? Can we even come up with a fair rate at all?

So, we pulled just three random customers, just to illustrate a point. They're all low-income customers. Two of them live in single family homes, and the third one lives in an apartment. And this is the peak day of the year (summer peak, not winter peak). And so, you can see these particular customers have very variable consumption, hour by hour. Here's the peak hour for that particular utility at that time. So, it's 6 PM. If that peak had occurred at 4 PM, you would have very different capacity costs, but so would every other customer. So, at 6 PM, you have some pretty interesting capacity costs implications. So, the capacity costs around 200 bucks a kW. (I changed the number to mask the utility involved here.) There's an 11-cent margin, and what I mean by that is the retail rate of electricity minus the annual average cost of procuring for that energy. And in this case they have about 11 cents of energy sales margin in a year. So, a reasonably high margin business. So, the first customer generates about 1,000 bucks of margin for the utility, towards fixed cost. The second customer produced about 600 bucks, and the third on is about 300 bucks. So, the first two customers look a lot more attractive than the last one, but let's throw the capacity costs in there. This is where it gets interesting. The first customer has $1700 worth of capacity costs. The second one has $800 of the capacity costs. And the third one is 154 bucks. What's the net result? The first two customers lose quite a bit of money. They're not contributing anything towards the fixed cost. Only the third one is.

So, again, when we try to generalize customers into classes and think of averages, we basically stopped doing that, because, by definition, if we average, we are taking extreme variability in individual usage and their contribution towards fixed costs and pretending that we know what that implies for the business as a whole, or those customers as a whole. And, by the way, the total customer discount was almost $600 for Customer A, because they got about 5 cents a kilowatt hour discount, plus $10 a month in discounts on the monthly fee. The next customer might have $400.

So, again, at this point, looking at this stuff, I have no idea what a fair rate is for this. Itis hard enough to come up with a fair rate to begin with. How do you do it for low income customers?

So, a couple observations. These are somewhat obvious observations, but hopefully they'll connect the dots. Low income energy usage is definitely not homogeneous. They may use less than others in some cases, but they are not homogeneous. And one of the previous speakers made the point about how the people who participate in these can be very, very different from those who don't. Fuel type matters and family size matters. The condition of the building matters. Location, climate, all these things matter. Sometimes low-income households contribute towards the fixed cost, with all these variables. Sometimes they lose money to the utility. So, again, we have no way of figuring out what a fair approach is.

So, the original question for this panel was, what would happen if you have a two or three part fixed/variable rate. How would customers be impacted? What if we can calculate all these impacts for every single customer, by the hour, individually? Basically, let's rerun everyone's bills for the last year and see what would happen. And then we'd know what the answer is, and who the winners and losers are.

So, my counter to the comment earlier about why do we even bother doing AMI, is that if you don't know what these impacts are, we're just wasting time speculating. We may actually be hurting the constituents that we're trying to help. The value of the data is really significant. Without this info, we are just operating in the dark, and it's really hard to design low-income rates. It's hard enough to design a good fixed/variable rate, and there may be other ways of subsidizing low-income customers…giving fixed dollar amounts per month, based on family size or other metrics…I'll let others opine on the fair way to do it. But let's at least create an incentive system that aligns the rates with the cost of the business, and then we'll figure out the subsidies, so thank you.

Speaker 4: Thank you. It's a pleasure to be here on this very important and interesting topic. So, why are we here? In the last 10 or 15 years, there's been this misalignment of rates and costs. This graphic here on the left shows hypothetical data, but it is consistent with data that we're familiar with in terms of cost and rates. Variable costs, fixed costs, and demand costs of the utility are recovered primarily through volumetric rates. The fixed and the demand component of utility costs are really viewed as kind of the costs of access to the network, in some sense, and also the capacity demands that each customer places on the network. In some sense you can think of that as a separate service in its own right, with a separate supply and demand curve. And then you've got the usage component. This is very common in network industries. You've got demand for access to the network and then demand for usage, in telecommunications and other industries. And, for a long time, we've had this kind of misalignment of costs, and it's generated a lot of inefficiencies, and we've lived with them, and we've dealt with it through internal cross subsidies and what have you.

It's always good to try to eliminate those internal inefficiencies for their own sake. But I think there's another reason why this is becoming more important, and that has to do with the competitive pressures on the distribution side that exists. So, for example, distributed energy resources. In a sense, that's really a customer making a decision to bypass the network. And this was very common in telecommunications, when competition was first emerging.

So, in my opinion, the key is that you want to give consumers the correct pricing inputs to making that bypass decision. You want those bypass decisions to be economic. The entity that can provide the service at the lowest marginal cost should be the entity that's providing it. The customer's decision to invest, say, in solar PV, is driven by many factors, but in particular is driven by the kilowatt hour rate. So, the higher the kilowatt hour rate, the more incentive the customer has to purchase solar PV and bypass the system. So, going forward, this is about ensuring the consumer decision is made based on correct pricing, or as correct pricing signals as possible.

So, the topic was progressive versus regressive electricity rates. When I first started thinking about, I was like, well, what is exactly a regressive or progressive electricity rate? So, then I got inspired by tax policy. Basically, an electricity rate varies with your income level. So, a progressive rate would be, say, a kilowatt hour rate that is lower for low-income consumers and higher for higher-income consumers. And I don't think that exists, really, in electricity rate making. I mean, maybe you can make a case that inclining block rates get at that, but that really requires evidence that low income consumers do in fact purchase less energy than high income consumers. And there's been evidence presented here that supports one view, and some other evidence that it's much more variable. I think probably the closest thing you have to a progressive rate structure are some of these kind of low-income assistance programs like the LIHEAP program and the CARE program in California, paid directly to the consumer, and in some sense the effective rate to the consumer is lower because they're receiving this kind of payment. But in some sense, the volumetric rate that is the same for everybody is a very regressive rate, because it doesn't vary by income level.

So, the implication of this is that, really, we're talking about rate reform. So, if we agree that the difference between the rates and the costs in the last slide are significant enough, then the question is, rate design reform, what impact will that have on consumers? There are going to be winners and there are going to be losers, and the question is, can we make a statement about whether low-income consumers are going to be worse off than higher-income consumers? It's a difficult thing to do *ex-ante*, because rate design reform could be either implementation of demand charges, or it could be kind of a time-of-use-type pricing, or a dynamic type of pricing. Those are kind of the things that I'm referring to right now. In terms of making predictions about what impact that's going to have on consumers, there are a lot of parameters at play here.

So, for example, the type of rate design reform is going to be important. For critical peak pricing, when is the peak going to be? What kind of demand charge is the program going to have? Revenue neutrality is a common feature. So, the actual rate design reform will have a big impact on the winners and losers.

A second variable is the customer load profile. Specifically, with these type of reforms, non-peaky customers tend to benefit. So, if you're going to implement the demand charge, or critical peak pricing, if you consume a lot during the peak hour, you're going to be harmed by it. If you're relatively flat load, you're going to actually benefit from it. And so, are there differences in consumption profiles for low-income customers and non-low-income customers? Then you've got demand response, which is the elasticity of demand. So, if I impose a demand charge, how is the consumer going to respond to that? How is a consumer going to respond to dynamic pricing? Is the elasticity of demand for low-income consumers different than for non-low-income consumers? And then you've got potential variation in how the regulator actually implements these types of programs. What kind of consumer outreach programs do they have? What kinds of education programs do they have? All these things are going to be very important.

So, unfortunately, *ex-ante*, it's hard to say whether low-income consumers are going to win or lose. I think that in the example that Speaker 2 mentioned, where you're just talking about a fixed price increase, and you're not talking about a demand charge or critical peak pricing, then (again, under the assumption that low income consumers consume less) I think, *ex-ante*, there, you can conclude that the low-income consumers are going to be harmed. But if you're talking about rate design reform with more aspects to it, then it is very much, *ex-ante*, hard to determine what the outcome is going to be, and you have to kind of do different types of pilots and kind of see what's out there.

So, the question is, have any of these studies been done, or what kind of work is being done on those questions? And my last two slides kind of get at that. What I did was kind of a literature review, to see what's out there in terms of publicly available information. It's not by any means a random sample, although I did try to find what was available. There's just not much that's publicly available. I probably missed a few. The two on the top come from the Brattle Group. And then the third has got to do with somebody at the Lawrence Berkeley National Laboratory. What they do, basically, is take different customer groups and look at different rate reforms and see how the customers fare.

In the first study, it was looking at dynamic pricing of critical peak and seeing how customers fared. There were four utilities that were the basis of the paper, Baltimore Gas and Electric and some others, and it was a study of Critical Peak Pricing. And so, the conclusion there is that low-income customers are as responsive to dynamic rates as other customers, and that many such customers can benefit even without shifting load.

Hledik & Greenstein, in the *Electricity Journal*, looked specifically at demand charges. They had information from a utility in Vermont. And they looked at the impact of demand charges. And they did not assume any elasticity. They just kind of looked at very flat-profile customers. Flat load customers will benefit. Those customers that are not flat load may be harmed, depending on the type of rate reform and the demand charge. And they found that, on average, demand charges did not affect the bills of low-income customers differently than they affected the bills of non-low-income customers.

And then the last study is very interesting, because they look at "vulnerable" customers, which are not just low-income customers. They're low-income customers, and they're also the elderly population, for which you can have low income and high income. And then you've got the chronically ill, which is also a sub population of the vulnerable. And that's a very long study. It's about 100 pages, and it's got really good information. They look at this population, their usage, and how they responded. So, they take a look at elasticities. They look to see whether they had to cut back on energy consumption, and whether that was correlated with significant discomfort that they experienced during the month. So, I just took one headline here from it, but I would urge everybody to go dig deep into that paper, because that's got a lot of good findings. But the basic punchline there is it's not clear that, *ex-ante*, low-income people will be harmed by the type of rate design reform I've been talking about here.

Although there are not a lot of publicly available studies looking at the impact of rate design reform, as you can imagine, a lot of utilities are doing these things internally. They're hiring consultants to do them, as well. They get out in the public only if there's a rate proceeding where evidence is used. But here's work that the Brattle Group did for a utility a few years back. The utility was interested in the question, if you take the volumetric costs that are currently being recovered right now through volumetric rates, and you basically recover all those from a demand charge, and you don't assume any response in terms of elasticity, what kind of impact that would have. They were interested in seeing the distributional impact of that. Now, one thing that comes out is that, with this type of rate design reform, you're going to have winners and losers. So, in many instances, half of the customers are going to win, and, in some sense, half the customers are going to lose, just because of their profile. Again, this is before you make any assumptions about how demand elasticity kicks in.

So, from this experiment, about 53 percent of customers will experience a bill decrease. Some low-income customers actually do better than some non-low-income customers in this particular experiment. To the right of where that line crosses, then customers start, You have some customers paying more. And there are some low-income customers that fare worse than some non-low-income customers whose bills also increase. Probably the biggest thing, from a public policy perspective, is that there's a small segment, maybe five percent of the customers, that will face significant increases, right up to a 50 percent bill increase, from this type of rate reform. Those customers, and they're both low-income and non-low-income, they're going to be very vociferous about this. They're going to be very loud. Now, what do you think the customers that are saving 20 percent on their bills are going to do? Do you think they're going to say anything about how great the regulator is or how great this program is? Are they just going to pocket that and be completely quiet? So, that is probably the biggest impediment to that kind of rate reform process.

One of the questions that was specifically asked was, how would this type of two part or three-part rate reform affect low-income customers? So, as I discussed, it's very case specific. It's very specific to the type of rate design, and the characteristics of the load. So, in some sense, related to what Speaker 3 was saying, it's very hard to kind of say, on average, what are going to be the effects. I think the types of studies I discussed are going to be required to determine the impacts of specific rate designs.

But I guess the key message is that, from the perspective of moving towards rates that are more aligned with marginal costs, there are probably more winners than losers. And so, from a compensating principle, the winners can pay off the losers. That is an indication of good public policy, and a reason to move forward. But the key would be having rates aligned with underlying costs and dealing with any kind of low-income issues in some manner other than rate distortions for everybody.

Clarifying question 1: Going back to a remark that was made earlier about how you design a proper tariff, the coordination exercise seems extremely complex to me, and I'm wondering whether this notion of local energy markets and the utility directly dispatching down to the level of a household and then pricing based on generalization of DLMP is purely academic, or if there's a practical application of the concept?

Speaker 1: People on the panel seem to be looking at me, as though I have something to say about this. [LAUGHTER] I think Bill's the guy to talk about distribution-level locational marginal prices. I mean, in terms of actually computing distribution-level locational marginal prices, I would say that, at this point in time, from a computational perspective, that is an academic exercise. I mean, there are still kind of fundamental questions about what assumptions you have to make about consumer utility functions, and how you can actually compute this at a large-scale level.

On the local energy markets question, I think that there seems to be a lot of interest in that, especially in Europe. The perspective that I've seen seems to be, in many cases, people saying, "Well I can avoid paying for distribution networks if I sell energy to my neighbor," and that's not an effective model. There are a lot of reasons why that's not good. So, I think that as long as those models are driven by people who are choosing them because of something like they like buying locally or something like that, or maybe they can actually get a cheaper energy price because the network is constrained up at the transmission level, or something like that, that's great. But somebody still needs to pay for the networks. I guess those are the two comments I have on that.

Speaker 4: I would just add, that, on the retail pricing level, in addition to rates following costs as much as possible, there are kind of the Bonbright principles of pricing. One is simplicity to the customer. In some sense, that's why volumetric rates have always been such an easy thing to understand. They've been so prominent because they're very simple to understand. So, as you add in things like demand charges, which has been a very controversial thing to do at the residential level, there's the concern about whether that's just not simplistic enough for the consumer. And so, when you get some of these other things here, I think you've got to take that into account, from a rate-making perspective at the retail level.

Clarifying question 2: With respect to your use of the term "penalty" with respect to a time-varying rates, I'm wondering what your underlying concept of equity is, and when does something become a penalty versus simply a reflection of, to use the term that Speaker 1 was using, short run marginal cost. So, if you can clarify what you mean by that from an equity standpoint that would be great.

Speaker 2: That's a fair question. Under a flatter rate design, you may have an elderly customer who is at home during the day and dependent upon maybe some medical equipment and cooling equipment, who might have this sort of load profile such that, were there to be a real-time price, or even a time of use price, that customer would end up paying more. So, by "penalty," I would refer to those folks who, with a change and rate design, end up with higher bills. And you can argue with the term "penalty" as opposed to "increase," but, hey, I'm an advocate.

Clarifying question 3: For all these residential demand charges, are these coincidental peak demand charges?

Speaker 4: For the example I had there for the utility, it was not coincidental with the peak. It is between nine and 6 PM. And, during each month, it's whatever the highest demand was during that time period. There were some other demand charge options that they asked us to look at as well. And if you look at demand charges that are in existence, they're all over. Some are very much coincident peak-type demand charges. Other are kind of non-coincident peak demand charges for that particular customer class. So, you'll find a wide variety of demand charges, in terms of how they're setup in the U.S.

Clarifying question 4: I'm pretty sure no one has ever thanked a regulator. I have two clarifying questions. One, I want to go back to Speaker 2. When you were talking about the pass-through in Massachusetts, for the utilities, it's a pass-through, and they don't care. I guess both the capacity charges and the supply charges are just that. When you said that the utility doesn't do anything, I'm just curious what you think they can do? That's the first question. For the second question, I'm happy if anybody can address this. I didn't hear any mention of a low-income discount. Certainly, the panel has done an excellent job of talking about how complex it is to design low-income rates. But are our low-income customers better off if a regulator just uses the low-income discounts? So, I'm curious about your answer on that, but I'm also curious as to what you think the utilities in Massachusetts can do. Because we know why our capacity costs go high, and we have incredible pricing in winter because of gas constraints.

Speaker 2: Yeah, so a couple quick comments. One of the things that's been interesting is that, whenever I've been to a meeting with both regulators as well as utility folks, I often ask, "Where on the bill does the summer capacity cost end up? And where does the monthly transmission capacity cost end up? Does it end up on the supplier bill, or in the distribution bill?" And most of the time people cannot answer the question, so they don't even know where it ends up or whose responsibility it is. It just reflects that it's not something they're focusing on. So, that's on some sort of an anecdotal level.

We work with both investor-owned utilities and municipal utilities. And the reaction is completely different. Because, on the municipal utility side, they have to care about that bill, and they care about the end price points. So, I guess one of the costs of decoupling has been that that price signal has been lost at the utility level. I would have a bunch of ideas in terms of how to re-create that price signal, but I think there's a long conversation in terms of, how do you create that incentive? But it's clear that there's not even awareness of what those capacity costs are, or how they get transferred to the bills, for large parts of the organizations. And we've been really, really surprised about that. I'm not sure that I'm answering your question.

Questioner: I'm just not sure I agree with you, but I'm happy to talk offline.

Speaker 2: And maybe it reflects that we are not talking to the right people, so.

Speaker 3: I wanted to address your low-income discount question. It's a complicated one, in the context of this emphasis we've had this afternoon on time-varying rates, and customer response, and customer load shape variability, and difficulties and challenges associated with coming up with a single rate design that is efficient and doesn't create other problems. There are some impossibilities there, given these dynamics. But, as we increasingly move towards time-varying rates…and even states like Massachusetts and Rhode Island, where there are not smart meters yet in their residential sector, someday there will be. Folks aren't going to install analog meters anymore. So, in terms of structuring low-income rate offerings, I think Speaker 2's model, where you can model different assumptions for individual customers, this would be an analytical approach that could go behind something that some folks refer to as "shadow billing," where you can provide a number of options for customers. Perhaps you can let low-income customers opt in to the most advantageous rate, and have ongoing analysis to show what the most advantageous rate would be for that customer, either over time or for a particular month. One can imagine a "hold harmless" structure, where, if you had a vulnerable customer like that hypothetical elderly person we were talking about before, that we make sure she doesn't experience a big increase, when it would threaten her health and safety. So, anyway, there are low-income rates, but there are also sort of rate design elements and structural elements that we can think about as we increasingly try to tie retail pricing to what's going on in the wholesale market.

I would also add that discount rates, as they exist in the states where they're offered, can be very, very effective tools in lowering and equalizing home energy burdens.

Another model is one that's offered in Illinois, and it raises some questions, I think. It's a percentage of income payment plan, where the customer's discount, is capped at a preset portion of the household's income in order to achieve a target burden level or affordability level. I think, personally, that that's sort of the Cadillac of the discount models, but I don't understand yet how it really is compatible with time-varying rates. And, in fact, I would have a question for Speaker 1 as to how that analysis was colored by the extent to which low-income households are participating, and whether they're on a real-time price or critical peak price or a time of use rate. If the payment is capped, what are we getting there? The same issue would exist in Ohio, I think.

So, anyway, I believe your question is important, but, really, if we think about how more vulnerable customers approach these different rate offerings and what we do to make sure that the regressivity that currently exists isn't exacerbated as we increasingly move toward time0varying pricing, I don't think that's necessarily rocket science, and I think that solutions, if we have the commitment and the will, can be implemented.

Speaker 1: On the question about low-income discounts, I think there are a couple of things that are important to point out. I don't think we should be considering low-income discounts only from the perspective of public policy. Speaker 3, you mentioned that these public policy goals are something we should be trying to achieve through the rate. There are actually economic efficiency arguments for why you would want low-income discounts, particularly on the fixed charge. If customers have budget constraints, and if I'm a low-income customer, and I'm experiencing stress on my energy bill, and I'm basically reducing consumption of other goods as a result of that, especially if the energy charge that I'm paying is not a short run marginal cost, there's actually a consumer surplus loss there. There's a utility loss there. So, there are actually good, sound economic efficiency arguments for why you would want low-income customers to contribute less to some of these fixed charges.

The second thing I'd say about low income discounts is that it's very difficult to identify low-income customers, as we were talking about on the panel, with respect to load profiles. But it's also difficult for low-income customers to elect into these programs. So, the Low-Income Heating and Energy Assistance Program, LIHEAP, at the Federal level, touches about 22 percent of eligible customers. So, only 22 percent of customers that are actually eligible for LIHEAP actually participate in LIHEAP. So, if you're hoping that customers are going to opt into these low-income discounts, I just don't think the data suggests that that's actually going to happen in a way that achieves some of these goals. And so, combined with the fact that there are economic efficiency benefits, and it's really hard to identify these customers, I think it has to go to the default rate. The default rate for these low-income customers has to be something that is economically efficient and also not distributionally crazy.

And then I think the other piece of it is that the wheels are off. Rooftop solar breaks the game. It completely changes the game, in terms of how we think about rate design. And so, arguing that we need to maintain today's existing volumetric rates to protect these low-income customers just is not consistent with the current system that we have, where the whole idea high volumetric rates protect low-income customers is based on the idea that higher-income customers can't run away from those rates. So, if you can run away from those rates by installing rooftop solar, or even investing in energy efficiency, that completely changes that argument.

I didn't get to this in the slides, because I just talk too much, but what our evidence shows is that volumetric rates are worse for low-income customers than even just uniform fixed charges. Again, this is based on the case study that we did, so it's going to differ depending where you are, but when about 20 percent of single family homes have rooftop solar, low-income customers, or at least the bottom income quintile, are going to be paying more under a volumetric rate than they would be under a rate with an efficient short-run marginal cost and a fixed charge recovering those network charges. So, I just think we can't continue to think about high volumetric rates and then low-income discounts. I think that system is not consistent with the kind of suite of technologies that we have today.

Moderator: Thanks. I do need to make factual correction of sorts. For LIHEAP, 22 percent is an extremely squishy number. I mean, there's no question about the numerator, but the denominator is basically an unknown. Usually people use census data. The census data count a lot of people as low-income who aren't, and also leave out people, and LIHEAP, of course, does not go to people who don't have bills. So, the truth is, we don't really know. I mean, we've tried to get at it in Massachusetts. We think it's a multiple of that. It's probably closer to 80 or 90 percent. But the truth is, we don't really know. One thing I'm sure of is that it's not 22 percent.

Speaker 1: The U.S. Congress thinks it's 22 percent. They could be wrong.

Moderator: Well, we know how reliable that is. [LAUGHTER]

Clarifying question 5: I have a clarifying question for Speaker 2 about the tool that you presented that could look at the impacts of rate design changes. I was happy to see that it had a behavioral component in there, but I was a little unclear if that was just an opportunity for the user to make stuff up, or if there's information that you bring to the table about that.

Speaker 2: Yeah, that part was simply just an ability for somebody to input an assumption for the shift. That part of it does not analyze it, but, to me, the objective point is that there are a lot of people out there who now have developed computation, who have the computational abilities to basically analyze and do simulations of every single customer individually by the hour. And so, the point of that, really, was more abstract, which is that a lot of the debates that we have, we could end simply by just running the numbers, and then you'd know what the outcome is. And if you want to speculate on possible outcomes, what percentage the load will shift, and those kinds of things, then you'll have to do a bit more analysis and look at it. But the other side of that is that we also have a lot of laboratories out there for this stuff. And what people don't realize is how much information is out there. For example, Massachusetts has 40-something municipal utilities. And some of them have time of use rates. And some of them have demand rates. They have experimented. We actually have some real live data from real customers who have participated in these programs. And you can just plug in your best results from those kinds of experiences, and not just do research on it.

***Clarifying question 6*:** If I can characterize what you were suggesting, Speaker 1, as moving to fixed or demand plus volumetric rates, and then dealing with the distributional equity by having, let's say, different discounts, in an earlier discussion with an ex-general manager of Austin Energy (of which I'm a customer, as it happens), he said that his company was prohibited from discriminating on that basis. And I wanted to get a sense as to whether that was his fantasy, or whether that was the People's Republic of Austin, or maybe it was the State of Texas and its rules, or whether, more generally, it had to do with undue discrimination across the U.S. In other words, to what extent could you do that, and to what extent, on the other hand, would it be better, for example, to try to deal with low-income customers with something like more progressive earned income credit-type provisions.

Comment: What exactly did the person from Austin Energy say?

Questioner: Well, this might have been after a couple of beers, so I don't think either he nor I would attest to it, but I think he claimed that if they moved to a larger fixed charges, they would not be able to give different fixed charges to different customers on the basis of income--that they were prohibited from doing it.

My understanding is that the way low income is subsidized is through various weatherization and low-interest loan programs. So, whether it's self-imposed or not, there appears to be some prohibition against more direct subsidies. And I just want to get a sense of whether this is completely atypical, in which case it's not a big deal, or whether there are a lot of states that might have prohibitions on what seems to be a very sensible approach.

Speaker 1: There are prohibitions against discriminatory rates in many places. I think the historical argument for that is that, if I have two customers, maybe across the street from each other, connected to the same distribution feeder, they should not be paying different rates. And then you can kind of abstract further and further away. Two customers in the same neighborhood. Two customers in the same city. So, the idea of nondiscriminatory rates basically has been interpreted as the idea that two customers that look the same that are in basically the same area and consume roughly the same amount shouldn't be paying different rates. I would argue that that needs to change. Because, again, we are no longer in a world where we can afford to continue to do the same things that we've done in the past. And so, there are real costs associated with continuing down the path that we have with the current kind of rate structures that we have, with respect to distributed energy resources. So, if you continue down that path, we're going to drive unnecessary costs, and potentially drive unnecessary emissions--counterintuitively, but there have been some folks from the University of Texas that have shown that, especially with distributed storage. And we're going to have potentially very substantial cost shifts from higher-income customers to lower-income customers. So, I don't think that's a tenable solution. So, we need a different solution, and I think one of the best solutions that we have, or one of the biggest levers that we can pull, is moving to a more efficient rate designs. Now, if you move to more efficient rate designs, and you have efficient recovery of distribution network costs, the only way to really avoid having really negative distributional outcomes, or maybe what's called undesirable distributional outcomes, is by price discrimination with respect to the fixed charge. Maybe not the only, but one of the best ways. So, I would argue that, yeah, there are many places that that is the case, and I think that needs to change.

Speaker 3: There are a couple of states that either statutorily, or, in the case of Arkansas, constitutionally, prohibit cross subsidies in utility rates. Texas is not such a place. And particularly Austin. There used to be a discount rate offered pretty much across the state. There were shenanigans where the legislature basically took that money back and applied it in mischievous ways, all of which I can't remember right now. But, having worked in Austin with legal services and others there, there have been low-income discounts. Some of them were temporary. There are also variations in the regulatory consumer protections, which in some ways function as a discounted rate, and result in some rate payers essentially paying a tiny fraction more into protections for folks who have trouble making ends meet every month. So, whoever told you in the bar that there's a prohibition, I just hope that that person was buying. [LAUGHTER]

Moderator: So, I need to defend Arkansas. I actually worked there for about 10 years on energy efficiency with the utilities and the low-income programs and the Commission. And there is no constitutional bar. I mean, that argument is raised. There's a very strong cultural bar that almost has the force of law in Arkansas, so it was a barrier to getting a low-income, in that case, efficiency program done. I invented the idea of a severely energy inefficient home. We created a program for such homes. Well, guess what percentage of those were low-income homes? But everybody winked, and they were fine with it. So, I suspect that something like that may be what's going on in Texas.

Speaker 4: I'll just add, briefly, that the term that you find in a lot of jurisdictions is "undue" discrimination. And so, the question that leads to a lot of litigation is, what is undue discrimination? So, in some sense, it's got to be cost based. So, if you're going to distinguish in rates, and we've got some cost-based reason to do that, that could be fine, depending on the circumstances. I think the one issue they were perhaps trying to do away with in that legislation of undue discrimination is value-of-service pricing, where you kind of take into account, how much does that person value this service, and then let's do rates. So, it's interesting. Here, you might actually have value of service, but reversed, so you might want to be able to discriminate for low-income customers in that sense.

I know this is coming up in some net metering cases across the country, where the issue is setting different fixed charges. So, the issue being made is, I'm going to charge net metering customers a different fixed charge, because of the volumetric losses they're now recovering. And I think there's a big debate about whether those are appropriate to do for a specific set of customers, or whether you have to apply it to everybody. So, I know that there are decisions out there that might be enlightening, in terms of whether having a separate fixed charge for net metering customers that's different than everybody else is regulatorily allowed.

General Discussion.

Question 1. I want to ask a couple questions. Number one, thinking about low income subsidy programs, should we actually be worried? How much should we be worrying about price signals to low-income people? I remember when we adopted the PIP (Percentage of Income) in Ohio, someone who was testifying for the utilities said, "This is the wrong price signal." Somebody from the Consumers Council asked, "What does a price signal mean to a person with no income?" I'm still waiting for the answer to that one. So, the question is, what should we be focusing on? Income, or the design of the tariff?

My second question relates to that. Part of the theory that you were operating on was that, basically, low-income people would cover their variable cost and maybe make some kind of contribution to fixed costs, in which case, everybody's better off not shutting them off. So, the question is, what should we be focused on? How much should we worry about pricing efficiency, and how much should we be worrying about income issues, and allowing people to maintain service?

Respondent 1: Well, I'm not trying to side step your question, but it strikes me that we have, for decades, looked at the challenges faced by low-income households and having those households stay connected to utility service strictly as sort of an energy affordability issue, rather than, more broadly, as a home energy security issue. And defining so tightly what it means to struggle to retain adequate service, I think, has limited the solutions that are available to us. And you're absolutely right. You can have a percentage of income payment plan; you can have just a straight percentage discount. You can have a tiered discount, a percentage of bill. There are a lot of ways you can structure it, but they're all designed to lower that household's monthly payment and make the bill more affordable.

Now, far be it from me to say that we don't need to do that. 30 percent of the households in this country don't have sufficient income to pay for all basic necessities. And so, it's understandable why they're a little bit late paying their bill, and addressing unaffordably high energy burdens through a discount measure is absolutely a part of it. But shouldn't we, too, be looking at it as regulators, and say, "Well, what sort of performance metrics do we want to look at to complement the cost of service system and protocol that we've got? Why don't we throw in a disconnection metric, too? Or something along those lines that deal with home energy security?" I think there are ways, beyond discounts, that may be politically less untenable in states like Texas and Arkansas that bear trying out.

But, getting back to your question, absolutely. If we can agree that all you have to do is make a small contribution to marginal costs, and you're contributing to the system, and it's better to have that customer on than off--if we can all agree to that, and broaden that understanding, then that would be a good thing. But what happens when making that argument, as an intervener, is there's sort of a moral predisposition against anything that looks like a handout. There remains sort of a "blame the victim" mentality that is a hurdle, still, no matter what sort of economic argument you make. We have, in Massachusetts, an arrearage management program, so that if a customer will stay current, or make timely payments on the current bill and a percentage of their back bill, their arrearage is written down. And we have evidence that the entire utility system is better off when folks are covering a larger proportion of their current bills than they otherwise would have, and they're making a contribution to the utility's revenues that otherwise wouldn't be made. And, in other states, where we show these numbers, there's still reluctance to forgive these back bills that those people have accrued.

Respondent 2: A quick comment on that question. I would not throw away entirely the price signal to low-income customers. I don't think this is a provocative statement. I would think low-income customers do respond to price signals. Low-income electricity consumers are also consumers of a whole bunch of different services. Telecom, cable services, wireless services, and so they're faced every day with market-determined prices. So, I think there is a balance, to kind of not throw away price signals entirely, and say, "Well, low-income consumers will not respond at all to price signals, therefore we don't have to worry about that aspect in the rate design." I think that's still is an issue that needs to be considered, and I would kind of balance that with some of the other issues.

Respondent 3: Just to add to that, just reflecting on a conversation that I had with a general manager of a relatively large municipal utility that does not have time of use rates today, and that also doesn't have really material low income discounts, their approach was that they wanted to introduce time of use rates to everybody, so that the price signal is going to be clear. They said, "We have a business-wide issue. We have to increase prices during peak periods, and let the market determine whatever that cost is going to be." But, with regard to subsidies, they basically took the approach that said, "We have to separate the price signal from the subsidy, and price signals should be the same to everybody," and they will basically give a fixed amount of bill credit each month to low-income customers, for some amount that's somewhat arbitrary, say, $10 or $20, basically so that those customers still have the incentive to shift their consumption at peak hours. So, they completely separate the two notions.

Respondent 4: There are generally two things that people are worried about, with respect to the response to marginal price signals for low-income customers. One group says, "Low-income customers don't have Nest thermostats, or Tesla Powerwall batteries, so they won't be able to respond to these price signals, and therefore they will be unduly harmed." And then the other group says, "Who are the people clipping coupons and trying to save money on their groceries and doing all this? Low income customers are going to be the most responsive to price signals." And, depending on the paper you look at, there's evidence, empirical evidence for both of those arguments. But I would just, I think, default to Respondent 3's point that, if you can keep the marginal price signal and actually send that efficient price signal, while achieving either economic efficiency or public policy goals, then there's good reason to try and do that.

Question 2: I just wanted to come back that was made here about undue discrimination and connect to what Speaker 1 was talking about. The thing that I found most interesting about the paper and the analysis that you did was that it didn't require self-reporting of income. It didn't require the administrative burden of checking, and all of the other kinds of things that would be a problem if you're trying to do it across the whole population. And so, it was an administratively simple system, based on the granularity of census blocks, and therefore it also became, naturally, an "opt out" as opposed to "opt in" story. So, that becomes the default. Now you catch all the people who are not paying attention. And, obviously, the efficiency argument that you make is that the allocation of the fixed cost is not an efficiency story, as long as you don't kick them off the system. So, there's no tradeoff. So, unless you have a principle that is new to me from Austin, Texas, of, "We just don't do this," it seems to me to be a very, very attractive methodology. And that opt out story, and making it based on census blocks struck me as novel, and do-able, and implementable in lots of places. There's still going to be variation within the census block. I mean, it's way better than what we're doing, but that's not enough to stop people from complaining. So, what do you think is that residual variability that may be impossible to pick up?

Respondent 1: You can actually quantify the number of type one and type two errors that you have, because, for a census block group, you have the distribution of incomes within that census block group, and so you can say, "OK, if I gave this discount for this census block group, what fraction of high-income customers am I accidently subsidizing, and what fraction of low-income customers am I missing?" And it's going to differ, depending on where you are. In the Chicago area that we looked at, ten percent of census block groups had 95 percent or more high-income customers. And then there was another fraction of census block groups that were predominately very low income. I think the bigger challenge that we saw from the data is that there are a lot of census block groups that have moderate and low-income customers living together. There are few that have high-income customers and low-income customers living together. Not zero, but they are relatively few. But I guess the point is that, if you're going purely based on geography, you can quantify the kind of Type one and Type two errors that you would expect to get. I don't know if that answers your question.

Questioner: I think you're trying, but, in actually implementing this, the problem would be the low-income people in high-income census blocks. That would be the one, because now they'd get a big increase in their fixed charges, because they're in the high-income census block, and it's the census block charge. And, obviously, all kinds of people are going to come out to complain about that. So, that's the one thing that makes me hesitant about this, but I think the basic argument is extremely powerful.

Respondent 1: I don't argue with that. That's going to be a challenge, and, in general (I think it was Speaker 4 who was saying this) when you change rates, especially if you're moving towards a more efficient rate design, then some percent of the customers are going to benefit immediately. Some percent are going to face higher rates immediately. And then the argument a lot of people would make is that in the long run, probably a lot of customers, or all of the customers, are going to benefit as capacity costs decrease and system utilization increases, *et cetera*, but those benefits accrue in the long term, so you've got kind of a silent section of the customers that benefit, a really loud section of the customers that are harmed immediately, and then a broader, also probably silent, set of customers that benefit in the long run, so you have this political economy problem, no matter what the rate design does. I think you're always going to face that. I think there's room for creativity around how to solve that.

Respondent 2: I just want to add that it's more than a political economy problem. It's a real equity issue, and there are a lot of proposals these days for identifying (what do they call them?) "energy justice census blocks." And it's exactly the problem that the questioner points out. You've got people in those census blocks that really shouldn't qualify, and you have a lot of people who are not in those census blocks who are left out who shouldn't be.

Respondent 3: When you get down to this census block level, you pretty much need to rely on five-year American Community Survey estimates. And in a lot of the urban areas, Chicago included, the churn, census block to census block, can be considerable, particularly where low-income folks live. So, I'm not saying, "Don't do the analysis," or "Don't try to do these overlays," but we have to take them with a grain of salt, and ultimately, it's important to exercise some level of caution.

Respondent 4: It just struck me that this is kind of a form of geographic de-averaging of rates. And I know that term's got a lot of connotations to it, that a lot of times are not necessarily positive. I know that this would be an attempt to do it in a way that is perhaps more appealing from a regulatory perspective, but I think that is kind of a hurdle. I was at the Illinois Commerce Commission. I worked there. I began my career there, and trying to get a fixed charge for telephones for Chicago, for the suburbs, and for other parts of Illinois, was quite a challenge. And not many states do that, so I think that's another thing to take into account.

Question 3: Let me pick up on that. This question, I think, is mostly for Speaker 2. Your analysis could lead one to construct, essentially, an individual rate design for every customer. It's sort of the extreme of the geographical --

Respondent 1: It's the airline model.

Questioner: Yeah, it is. And, in fact, with all the warts that that model has, only now, you're dealing with a necessity of life. So, how do you construct a rate design, or a set of rules, whatever it would be, that would be fair, or at least seem as fair?

Respondent 1: I don't know. I would look at the gamut of customers that we work with. Some have only one residential rate, and others have 10.I don't know how they decided to segment those customers, and how they did it. But once you set those things in play, what I see is that people are often concerned about the change. They don't say whether the current rate made any sense at all. They just say, "I'm just worried about the change, the winners and losers." That's when you can just go and calculate the impacts, and figure out who the winners and losers are, and then you'll know whether it's worth the fight to go to get that rate done. But I'm not sure that we will ever see individualized rates in the utility business, although we do see them on the commercial industrial customer side, but they're negotiated rates there. But, no, I don't see how we could do that here. You can measure the impacts, but I think that's academic.

Questioner: And even that will change, because, whatever the parameters you choose to use are, people's response to those parameters will be different, in terms of their demand, their load pattern, and all that. But I will say that there is a certain amount of that segmentation done in the low-income area. Speaker 3 mentioned a couple of examples, like arrearage management. You've got to be in arrears. You've got to know about the program. You've got to apply. So, it's people in relatively extreme economic conditions. LIHEAP usually has an extra grant. It's not usually enough, but at least it's something for people who are high-use. So, there's a little bit of that in the system. But beyond that I think it's fraught with all kinds of problems.

Question 4: Speaker 2, I want to convince you. [LAUGHTER] You're on the wrong side in this fixed cost debate. Let me give you my argument. Net metering. Speaker 1 mentioned it. That is a subsidy aimed at wealthier people, right? And it works because we have a pure variable one-part rate. Those kinds of opportunities are going to grow and grow, and they're going to be more available to wealthier people than the people you're trying to protect. Speaker 1 said this before. And your constituents are going to end up having to carry the fixed cost of the electric system as those people exit the system.

I think the next big argument's going to be whether people who leave this system and disconnect will pay an exit fee. That's coming. And if they don't, your constituents are going to end up paying more and more for electricity. And this idea of discounts for low-income people sounds better than it is, because it just moves more cost to the wealthier and gives them more incentive to leave, and those opportunities to leave are growing. So, I would say to you, you're on the wrong side. You ought to be strongly supporting two-part rates with a fixed charge to make sure that these wealthy people who want to leave the system are going to pay their share, and they're not going to be able to escape it through net metering. So, I don't know if I've convinced you or not, but I believe to the bottom of my soul that you got this one wrong.

Respondent 1: Well, you know, I appreciate that. What drives where I'm at on this right now is just the sheer numbers game. And I certainly acknowledge that when you move to a relatively higher fixed charge, that's good for some low-income customers right now. There is variability within the low-income universe. I certainly hear what you're saying with respect to distributed generation, and share your concerns about how the system will look in 10 years, as my clients are still going to disproportionately not have solar panels on their roofs, or own their roof or own Teslas. I absolutely agree with that and would concur that net metering and similar structures are absolute anachronisms and that the pricing associated with these, not only to connect to the grid, but with respect to output, that that needs to be reflective of a much deeper analysis of system costs and system benefits. But right now, it's a sheer numbers game, especially among elders. We see less variability in use by low income elders, there's less variability there. They would be harmed, for example. More would be harmed than would benefit from a higher fixed charged system. And do you know how I can tell that elders use less? I took a look at our moderator's bill. [LAUGHTER] Sorry. But, anyway, you make a great argument and I know it's not black and white.

Questioner: Let me just ask a question back. If I agree with your analysis, and that it's a pretty serious problem and it's a distortion in a lot of ways, why not address that directly? I mean, net metering shouldn't exist, for example.

Respondent 1: Well, how else do you address net metering, other than replacing the volumetric rate? It just occurs naturally.

Questioner: Well no, you could have two meters.

Respondent 1: Oh, OK.

Questioner: Yeah. That's under active debate in a lot of places.

Respondent 1: I'm in favor of that, but I think my broader point is true. I think the fundamental difference that's coming, and I don't know how soon it's coming, is that this isn't going to be a captive customer industry for a significant portion of the customer base in 10 years. And to continue to talk about retail rate design on the assumption that we're selling a product to a regulated captive customer is going to be increasingly anachronistic. Let's not chase after yesterday's problem, I guess is another way to say this.

Respondent 2: I have a few thoughts. One is on the numbers game and where we stand today. I think something like one percent of U.S. residential homes have solar, or something like that. So, it is a small number. You're absolutely right, but you have to get out ahead of the problem. And no one is going to do that except for maybe the utilities and the low-income consumer advocates.

So, when I say you have to get out ahead of the problem, if you look at the places where rooftop solar penetration is pretty high and they've tried to reform these programs, they've gotten killed. So, you have to get out ahead of the problem and say, "We recognize this isn't a problem today. Maybe it's only raising expenditures by a tiny percent for low-income customers today. But if we don't get ahead of it, it's going to become a huge political issue when it is a real problem." And that's exactly what's happening in these different places. And I cannot emphasize this enough. No, the distributed solar lobby is not going to stand up and say, "Hey, this isn't great for low-income customers, therefore we should change net metering." No one's going to do it, except for the utilities and the consumer advocates. And this is a problem, because the utilities get up there and say, "Hey, we think this is a problem," and everyone says, "Oh yeah? But you're the monopoly utility, and so we don't trust you." And so, nobody's representing these low-income customers. Honestly, I don't think anybody's doing it, and I think that's a problem. So, I think you have to get out ahead of the problem, and I think nobody's going to do it if it's not you guys.

And I'd also say that, on the two meters idea for solving the net metering problem, I think there are a couple of problems associated with that. One is that it's going to become increasingly complex, so it's no longer just a question of, do you have a rate explicitly for solar customers? Then it's, do you have a rate for customers with Nest thermostats? And then, do you have a rate for customers with Nest thermostats and solar customers? And then maybe the EV and storage and solar rate, and then you have this proliferation of rates that becomes incredibly complex, and it's just cumbersome.

Moderator: That's Speaker 3's solution, right?

Respondent 2: Well, also, you could end up with perverse incentives. I mean, if you say, "We're going to have a different rate for producing power than we are for consuming power," you might come up with these self-consumption incentives, which they have explicitly in Germany, but that you could implicitly create here in the U.S. by having the two meter solution. And you might drive customers to, then, storage, as it becomes increasingly economically competitive, and then you exacerbate the problem that you already had. So, I think there are a lot of challenges associated with DG-specific rates.

And then I guess maybe the third point I'll make is that net metering, as a construct, is not bad. You just need good net metering. You need to pay the customer the marginal rate that they should be paid when they're exporting. And if the cost of energy at this location and time is 10 cents per kilowatt hour, the customer, from an economic perspective, deserves to be paid 10 cents per kilowatt hour for producing power, so you don't want to get rid of the construct that you're paying them the marginal price. I think it's just that we're embedding all these additional costs in the marginal price.

Respondent 3: Let me just add to that. If the idea is that the net metering customer, the distributed generation customer, is avoiding a responsibility for fixed costs that they used to pay as part of their variable rate, then you do need to identify those customers. They are not very hard to identify. And they should have a separate rate that recovers that fixed cost that they would otherwise be avoiding.

Question 5: I certainly agree that there are lots of ways to skin the cat of not having net metering in terms of addressing DG issues that don't include two-part rates.

Speaker 1, I think I heard you misstate, basically, Ramsey-Boiteux pricing, which is not short-run marginal costs, and then fixed cost as the residual. Ramsey-Boiteux refers to the fact that in competitive industries, short-run marginal pricing converges to long-run marginal cost pricing under conditions of competition. In monopoly industries, of course, there are no conditions of competition, so you set volumetric rates based on long-run marginal costs, and the residual is actually the difference between what you can recover through LRMC pricing and the total costs. So, that's actually the residual, not the difference between short term marginal costs and total costs.

And Speaker 4 put up the slide that said, and implies as a result, that there's something somehow misaligned as a result of having a cost structure that isn't exactly the same as the revenue model. I could put up the cost structures and revenue models for 100 industries that look exactly like the one you put up, and those industries have all thrived for decades. I agree that, especially in the face of distributed generation, rooftop solar whatever (however large it's going to get, and be careful about assuming it's going to get all that large, because it can start to get swamped by utility-scale solar) the business model for distribution network companies, based on traditional 24/7, 365 day, flat volumetric tariffs is not a sustainable model. That doesn't mean that the answer is a fixed/variable structure. What it does mean is that the nature of the volumetric charge needs to adjust.

So, if you want to talk about efficient rate design, there are lots of ways to go at that: critical peak pricing, on-peak and super peak prices, time of use blocks, inclined block rates to deal with equity issues. And, as far as the equity issue is concerned, it's one thing to say that we're looking at a situation in the future where a small percentage of customers, and presumably the least capable customers, might be carrying a disproportionate share of the cost of a system capacity that continues to be used and useful. It's another thing to analyze the situation under conditions where you're continuing to reimburse distribution network companies for basically dark fiber, to use a fiber optic cable metaphor. And so, we need to be careful not to wander into using rate design to deal with a stranded asset problem.

And let's be clear. Grid defection is already happening. In Portland, for instance, there are block after block after block of street signs, stop signs, whatever, that have gone off the grid because Portland General is charging $12 a month for customer charges. And it just doesn't make any sense. So, they've gone off grid. It's only a matter of time before that goes to 10 kilowatt per month customers and 100 kilowatt per month customers. And so, we are looking at potentially, probably inevitably, a situation where we just need a smaller distribution network. And if we're looking at beneficial electrification, long term, electrification of heat, electrification of transport, we have to think in those terms. Because if we're going to continue to build peak capacity in the face of dumb charging or dumb water heating, or whatever, those inexorable opposing forces of grid defection, you know, the rich buying Tesla power walls and putting solar panels in their backyards and saying goodbye to the grid, as is happening in Hawaii, for instance, are only going to accelerate.

So, absolutely, it seems like the conclusion that we can't carry on as we have is correct. But I think there's neither an economic theory rationale, nor is there an equity rationale for saying that we should then jump to a fixed and variable rate structure. You know, critical peak, demand charges, critical peak and super peak time of use rates, so on and so forth, are perfectly viable alternatives and are perfectly consistent with both economic theory and with revenue models in other industries under different circumstances.

Respondent 1: I just want to push back. Sorry for the economics digression, for the folks in the room that don't care about this stuff. But Ramsey-Boiteux is talking about, or Boiteux was talking about, linear prices, and then, if you look at Brown and Sibley from 1986, or there are other folks that show that two-part prices can swamp the economic efficiency gains of linear prices under pretty much any assumptions. So, when you say there is no economic efficiency argument for going to two-part prices, that's just not consistent with the --

Questioner: That's not what I said.

Respondent 1: It is. It's exactly what you said.

Questioner: That's not what I meant to say. There's a rationale for long-run marginal cost volumetric pricing in a regulated industry. Remember *Munn v Illinois.* The purpose of regulation is to make sure that customers don't pay any more than they would pay under competition. So, long-run marginal cost pricing, volumetric charges, and then there's a second part, which is to recover the residual. What that part looks like, we can a healthy discussion about, so I'm not saying two-part pricing is wrong. But the idea that there's something wrong with having a volumetric component that exceeds the underlying variable cost of the industry…there's no rationale for that, for saying that that's inappropriate or misaligned or inefficient. There are lots of efficient industries where the revenue model has volumetric pricing that is at a level that recovers not only the variable costs, but a very large proportion of fixed costs. And that's a well-established industry model. So, I'm not saying you can't have two-part pricing. I'm saying that there's nothing that says that the residual is all the fixed costs of the business, and that that should be recovered through some sort of fixed charge. That is nothing that supports that conclusion.

Moderator: Can I suggest that this be an offline discussion?

Respondent 2: You mentioned defection. Defection implies competition. And so, I think the key is to make sure that that defection is fine as long as its economic defection. Right? What we want to try to avoid is uneconomic defection. And I think that too high a volumetric rate implies that some of those defections are uneconomic. And we need to consider that, and we can talk about the linear pricing afterwards.

Respondent 3: I'm going to skip the economic debate, but there's one important point that you just mentioned. Beneficial electrification impacts will probably be more significant than people realize. Right now, sort of the underlying assumption in a lot of the conversation here today is that whatever is happening is reducing sales, like solar is going to take away kilowatt hours from the grid. When we actually look at the meter data and look at the margins that come out of the current pricing schemes, focusing on electric vehicles and heat pumps, heat pumps, in particular, in the northern half of the U.S. can represent really significant margin increases. So, I'll give you an example. If a typical house is about $500 worth of margin, and under the current scenario you add a heat pump to it, that's easily another $500 to $1,000 of margin that gets added to the network. So, that often can actually offset the losses from solar completely. At my house, I have an EV and I have a heat pump. I have over 10,000 kilowatt hours a year of consumption because of those two things. So, as we look at the growth trajectories and the evolution of the technology, there's also a scenario, at least in the northern half of the U.S., where loss of system load will be completely offset by other end uses.

Question 6: I have a sort of a 50,000-foot question about the nexus or lack thereof between this panel and the morning's panel. The morning panel was in large part talking about the very large negative externalities of, particularly, fossil fuel generation. And that could amount to 10's of dollars per megawatt hour and cents per kilowatt hour. And so, I don't understand why it's assumed that we should ignore that consideration when we're talking about setting the relationship between volumetric rates and fixed rates for I guess what we call "cost basis." In other words, are we potentially ignoring a whole bunch of costs, like the negative externality costs? Thanks.

Respondent 1: In theory, yes. If you want to make a conclusion about whether the volumetric price is too high, you should look at all costs, private costs and social costs as well, and that implies looking at the externalities. Whether it's the role of the regulatory agency to do that in the retail rates, that's kind of an interesting question. I'm not familiar with examples where that's being done. There's an interesting paper by Borenstein about a year or two ago where he does a very comprehensive study, looking at this specific issue of whether the volumetric rates really in fact are not too high, when you take into account the externalities. You can take a look at the article yourself, but I think, even taking into account the negative externalities, we still have volumetric rates that are higher than what they should be.

Now, there's a big mix across the country. Some rates are actually perfectly aligned with those socially optimum rates, but in other areas of the country they're not, and Borenstein gives a nice map of every state and where those rates are either too high or too low.

Respondent 2: Yeah, that's a great paper. But I think then the interesting thing is that sets up kind of a tradeoff between efficiency and equity. At the beginning of my presentation, I made the point that there doesn't need to be a tradeoff between efficiency and equity, but, in certain parts of the country, if you want the volumetric price that the consumer pays to be equal to the efficient short-run marginal price, incorporating these climate and health externalities, you might actually have a short-run marginal price that is at or above what it is under the rate today. And so, then you have this problem of, "OK, well, that might be the efficient rate, but then part of that rate is the recovery of fixed costs, which consumers can avoid by doing different things." So, you basically have to choose. Do we want to price the short-run marginal price correctly, and allow customers to shift costs to other customers, or do we want to not allow that, and then potentially underprice or not price these externalities? So, that's a tough reality.

Respondent 1: If I'm remembering that paper correctly, the biggest source of the inefficiency in the pricing is the lack of real-time pricing--the fact that every hour, the cost is different, and nowhere in the country do you have that reflected in the price. So, when you compare the inefficiency from lack of externality pricing to the inefficiency from lack of real-time pricing you found much greater effects from the lack of real time pricing.

Question 7: I'll start by saying, without getting deeply into the economics, that for the last 30 years in wholesale power markets, we've demonstrated that the short-run marginal cost, as reflected in LMP, is the efficient price signal, not long-run marginal cost. And work that Bill has done, that I've contributed to, has begun to lay out how we can take that LMP model and begin to take it down to the distribution level, and even if we're not yet there at distribution level markets, we could reflect some elements of variable distribution costs in a variable distribution rate, if we were so inclined.

But what I really want to do is extend this argument about why we want to be thinking about dynamic rates, taking into account the very excellent point that we could help low-income customers by having differential fixed charges for the residual costs. I want to be very clear here, because I think it's not a fixed/variable cost problem, it's a recovery of residual cost problem, which, in a natural monopoly service, you almost inevitably have, because marginal costs will tend to be lower than average costs. You can at least start by doing an analysis that gives you an idea of what is likely to be a basis that doesn't inherently penalize low income customers, and then layer on top of that whatever low-income programs you want to have.

My real question is one of how we engage low-income customers in responding to variable pricing. I think the case for doing that is really rather compelling. If you look, for example, at Commonwealth Edison, where they have thousands of predominately lower-income customers on a real-time pricing tariff, what you see is that, because there is a correlated risk that suppliers face when they offer a fixed price, those customers that have been on real-time pricing that simply passed through the wholesale price, they've saved about 22 percent of their supply cost, relative to customers that were on the flat rate. If you look at the experience in Texas, and you compare what a pass-through of the wholesale price would be, compared to average retail rates in Texas, it's about 21 to 30 percent more that customers have paid, being on that flat rate, than if they had just accepted a pass-through of the wholesale price. Now, granted, we may have to do somethings to help customers out that don't have a capacity to deal with a single high monthly bill, and there are a variety of ways to do this.

The other thing we know, from some of the things Speaker 4 said, and certainly this is what we saw at when we looked at this in Ohio, is that low-income customers do tend to be price responsive, so there is that.

And then, finally, we have the capacity in our system to do much more on the demand side of the equation than we've done up till now. For example, on the residential side, I don't know how many of these are low-income customers, but the forecast is that we'll have about 30 percent of households that have smart thermostats by 2020. If we look at the overall demand profile, and you look at heating, air conditioning, ventilation, refrigeration, that's about 40 percent of overall U.S. electricity consumption. If you add into that some other kinds of variable loads, we have, either through thermal inertia or timing flexibility, really the opportunity to deal with getting much better asset utilization for utilities, integrating more variable renewables, improving the overall reliability of the system, if we can begin to tap into that. And so, my question is, why shouldn't we be doing that, and how can we engage low-income customers in being part of that process?

Respondent 1: I didn't know about the 22 percent low-income savings. That's an opt-in program?

Questioner: That's an opt-in program, and it's working very closely with the community group Elevate Energy to get low-income customers.

Respondent 1: That's a tremendous fact, if it's opt-in versus the default. In terms of engaging low-income households, I completely agree with you that, for many, there's large potential for changing usage to be able to benefit from a time-varying rate. We shouldn't just assume that if you don't have any money, you can't do that. The worry is that you do have customers perhaps without the upfront capital to invest in energy management equipment, who are fully dependent on heating or cooling, or other absolutely necessary equipment. Some people refer to heat wave pricing for customers like that.

Questioner: Just to be clear, the 20 percent was based upon no change in their electricity consumption pattern. So, this is just dealing with the price hedging premium that is built into the… [OVERLAPPING VOICES]

Respondent 1: Really, there are three design pieces that are critical, in my view. One, at least for some period of time (and if you want to segment out lower income customers, you can do that), have an array of options available, and let the customer opt in. Let the customer think about which of the available options would be most advantageous. Clearly, there has to be outreach in educational materials, but let's at least start with an opt in program, and not default folks, given all we've said this afternoon about the variability in load profiles among all residential customers, including low-income ones. Start with an opt in, maybe a shadow billing tool. These are available. I believe there's one municipal utility in California that has some sort of shadow billing model.

So, that's another piece, and then let's have a "hold harmless" approach, and, I know, if you're going to refund money if a customer makes a bad choice, how does that support behavioral change? But the bottom line is, unless you want to worsen some of the inequities that are built into the current system, you've got to hold folks harmless. You can't have some people paying extra who can't afford to. Otherwise, by definition, that regressivity gets worse. So, if you have those three things, maybe, for a particular period of time, combined with some effective outreach, and engaged community-based organizations do this, and you deal with the disconnection increases that we've seen with AMI in some jurisdictions (especially in California, we have documentation of this), then maybe we go a long way toward not only addressing the equity issues, but engaging customers in a constructive way, and helping them to benefit from what might be available through a particular time-varying rate. That's all I have for you.

Question 8: I have a question for Speaker 2. If 51 percent of low-income customers benefited from a program, is that making equity worse or better? I'm just curious.

I mean, is the idea that we can't make any changes that make anyone worse off or any low-income customer worse off? You're starting from an assumption that today's rate is good. You're basically starting from an assumption that today's rate is good for everyone. Right?

Respondent 1: No. What I would suggest is that if we're going to have a proposal with respect to rate design, and, let's be broad here, with respect to a utility capital investment, with respect to changes to the regulatory paradigm, with respect to the utility business model itself, and the way the utility is going to recover costs, part of the evaluation and review of that proposal should entail a clear review and assessment of the extent to which home energy security is impacted. Are folks who currently are payment troubled or vulnerable going to end up paying more? What other aspects of home energy security will be impacted by the proposed change? I would add that, while we need to evaluate a lot of these proposals using a long-term horizon, for low income folks, that short-term cash flow situation is of paramount importance. It's about buying the kid a pair of shoes next week. So, anyway, we need to conduct such an analysis, along with the other types of analysis that would go along with looking at the proposal, and, if you identify some negative impacts, we need to come up with a mitigation that would be effective. In some cases, that adds to the front-end cost of the proposal. So, it's a proposal-by-proposal approach, I would think. And what we would be asking is not, "Well, is one person harmed?" but to take a reasonable broad overview and have, as part of the regulatory review, a commitment to come up with those programs and policies that are going to not make worse what currently is kind of an inequitable energy and utility system.

Real quick, I believe that the real time pricing program we were just discussing is very low participation. I think one thing that it kind of reveals, in some sense, is that customer choices are important. There's a concern, perhaps, if you're in real time pricing, about the price spikes that occur. Low-income customers might be very concerned about that. Some customers just want simplicity, and we're going to have to deal with that in a new environment as well. Not everybody's going to want to go into real-time pricing, or what have you. And so, these figures are kind of reflective of how much people are willing to pay for kind of an insurance premium, so that the rates don't fluctuate.

Question 9: This conversation is focused on low-income customers, and I'm wondering about the broader question about leaving the grid and how those costs are allocated. And I'm wondering if you think that the two questions can be separated, or if you have to address the low-income problem. I mean, it's a much larger problem we're going to be facing. I don't know how many sessions have been held here on decoupling and things, but it does seem like today we've gotten very narrow in our focus on what is a much broader, troubling future. So, any thoughts on that?

Respondent 1: I would just say that the two overlap. They're both big problems. Some of the solutions relate to both, a lot of them don't.

Respondent 2: The reason why I think we're here is because of these changes occurring in the industry, which mean that, OK, we probably need to do rate design reform in order to deal with competitive distributed generation and what have you. And, as Speaker 1 mentioned, when you make any change, there are going to be winners and losers. That's going to be very difficult to deal with, and so the question then also is, OK, is there any evidence that low-income consumers will be affected in a disproportionate way, compared to everybody else? So, I see the questions as kind of connected. And so, if you're going to look at the impact of a rate design, then looking at the impact on low-income consumers is something that's going to be very important to regulators.

Comment: Think of it this way, I think the low-income folks are the canaries in the coal mine.

Respondent 2: I want to thank the hosts for initiating this discussion. Too often it gets brushed under the rug. So, yeah, there are some very broad fundamental, difficult questions, but to have a place to discuss equity and income related issues is very nice, so thank you.

Question 10: A lot has been said about the cost of capacity meeting peak load, both for demand charges and the capacity markets, and I think a lot of us are paying for a level of reliability that we probably don't need. And to, I guess, flip a lot of this on its head, something that came to mind was that you could offer low-income people some sort of payment, much like what demand response gets to curtail a load. They're the people who are most likely to be price responsive, just given that a relatively small amount of money might be more impactful to them. I'm reminded of the previous morning panel about how doing a lot of these things through fees and tariffs is a second-best solution. This might be a second-best way to have some level of redistribution, which in some ways feels like some of the point of these programs. And if you can kind of couch it all in the language of demand response, it might gain more political traction.

Session Three. Market Reforms for Stressed Conditions

Real-time electricity markets, and the organized forward markets supporting real-time commitments, confront increasingly stressed conditions. The growth of intermittent renewables, limits on fuel availability, and coordination across multiple energy markets have been cited as presenting new challenges that were unknown, or less material, in the early designs of organized electricity markets. Long-term forward auctions and capacity markets help address some, but not all, of the requirements of reliable operation and efficient dispatch decisions. Pricing and new market definitions are topics of great interest and many debates. What pricing reforms are being considered, and how do they relate across the different organized markets? What new products will drive changes in market design? What are common problems across organized markets, and where are there major differences? How can sequences of markets maintain consistency of prices, commitment, and dispatch to support efficient solutions? How do proposed market reforms address uncertainty, intertemporal optimization, coordination across markets, or other major challenges?

Moderator.
Good morning. The topic today is market reforms for stressed conditions. I originally read this as people who were stressed about market conditions. [LAUGHTER] And I suggest you either go to the Harvard Medical School, or wait two weeks, and Bill and I have a Tiki bar at an island near you, and we will serve appropriate refreshments ,and you can talk about the stress you might have about the markets. We've got an excellent panel. They are not the four horsemen of the market apocalypse, at least as far as we know.

Speaker 1.
Good morning everyone. The presentation I have today is to talk about some of the reform work on scarcity pricing that we've recently filed in PJM. We made a fairly aggressive filing, back in March. I'm going to talk about some of the work that went into that filing, some of the concepts, some of the issues that we see with the current market design. I do want to recognize Doctors Hogan and Pope, who submitted an affidavit in support of the design that we filed. So, thank you to them for their work.

I'll lay a little bit of groundwork on the reserve markets in PJM. Right now, we have a unique design, where we have two 10-minute reserve products that we clear in real time, and we have one 30-minute reserve product in day-ahead. So, we have kind of a mismatch of products, day ahead to real time. And the two 10-minute products in real time, we call them "non-synchronized" and "synchronized" reserves. Synchronized reserves are online, non-synchronized are, obviously, offline.

The average requirement for synchronized reserve (I'll stick to that one as I go through some of these examples, because that's the most valuable reserve product) is about 1600 megawatts, and the market bills about $44 million a year. So, a relatively small market when you think about PJM as a whole, where the energy market bills something around $30 billion a year.

Turning to some issues with the reserve markets that we have today, I think if you just look at the macro scale, we cover about half of the cost of this service through the market clearing price. And the other half is through uplift. And so, when you look at the numbers, they seem like small numbers because the reserve market's small, but if you thought about that in the energy market context, where you're billing $30 billion, it's pretty easy to look at that and say, "Something's not right." The goal is a uniform clearing price market, and you're paying half the revenues through uplift. Something is obviously broken. The revenues in the reserve market that are billed through the clearing price actually don't even cover the production costs in the market. So, the market revenues don't even cover the cost to provide the service. They cover about three quarters of it, something like that. So, at a macro scale, there are some issues with the reserve market that we wanted to tackle as part of this.

And so, I'll touch on a couple other issues too, including some of the price performance issues, looking at some stress conditions where you would think scarcity pricing would be something that would be in effect. On a couple days in January, January 30th and 31st, we had some severe cold weather, and we had zero reserve prices for probably about three quarters of the 48 hours over that two-day period. In the background, while this is going on, the reserve prices were zero. We have operators biasing the cases. And when I say biasing the cases, what they do in the dispatch solution is they say, "We need more energy, we need more energy." On average, that bias is to the tune of about 1,000 megawatts. And so, what's happening is, we're deploying the reserves that we have on the system, and the reserve prices don't respond, and they essentially do nothing. And so, you've got this sort of dynamic going on where the operators are working behind the scenes to make sure they maintain reliability. You've got the market prices sitting relatively flat and doing nothing. So, from a scarcity pricing perspective, when we look at this, it's clear to us that something is broken and needs to get addressed.

There are a couple of other issues behind the reserve market that I'll touch on, as well. We have this approach today where we have this Tier 1 and Tier 2 sort of bifurcated synchronized reserve market. And so, this Tier 1 product is essentially a voluntary reserve product. It's an on-line product, and we estimate the capability that units have on the system, but they don't get paid the clearing price, and they're not obligated to respond. But we consider this reserve as sort of what I'll call firm reserves. So, we make the assumption that it's going to respond, even though it's not obligated to. And the performance metric on that is about 60 percent. So, when you think about the supply curve, for every 100 megawatts of Tier 1 that I have in the market as part of the market supply, I really only have 60. So, from a supply curve perspective, you're artificially flattening out the supply curve, just because you're estimating reserves on the systems that aren't there. So, that's one of the things we want to address with the reserve market, because the supply function is artificially flat. It's artificially extended out to the right, and that sort of will predispose us to zero clearing prices, even when we probably shouldn't have them.

The second piece is the demand curve. Right now, we have a demand curve with a Step 1 level, that is the minimum requirements. That's usually, for us, the single largest unit on the system, probably about 1500 megawatts, something like that. And then we have the second step, which we call Step 2A, which is additional 190 megawatts. That step was put in in 2017, and it was really intended to sort of, at a gross level, make sure that we had sufficient reserves, beyond the minimum requirement, so that we didn't have scarcity pricing events or shortage pricing events for very small changes in the amount of reserves on the system. So, if you took away that Step 2A, you could have zero prices when you're one megawatt long the requirement, and prices in the penalty that are $850 per megawatt hour when you're one megawatt short. When FERC issued Order 825, which required all the ISO RTOs to do five-minute transient and shortage pricing, which we didn't do prior to that, we implemented that Step 2A in response to that in order to not have systemic volatility in the dispatch system. The intent of that was to make sure we assigned more reserves, because we didn't want to go short the minimum requirement by small amounts and have this sort of boom-bust pricing cycle. So, that's where we sit today.

With regard to the demand curve itself, that Step 2A, like I said, was really put in as sort of a safety net against system volatility, rather than actually going through some of the analytics on how to value reserves beyond the minimum requirement. And that's really the exercise that we went through over the last year or so, working with Doctors Hogan and Pope to try and look at a more rational way to form this reserve demand curve, based on system uncertainty.

The other thing we have going on in the background at PJM is we have things like this. This is wind capacity growth in PJM. So, if the states hit all their RPSes in PJM, the wind capacity in PJM will grow by 200 percent in the next 10 years. We have similar charts that show behind the meter solar growing on the order of thousands of megawatts over that same kind of time period. And so, you've got two dynamics going on. You've got the uncertainty in the intermittent wind that we can look at and see and calculate. And then you have the uncertainty of the behind the meter solar, which really manifests as load forecaster. So, we've got supply uncertainty. We've got demand uncertainty. And so, we've got a bunch of things that are going to change within the next five to 10 years here pretty drastically, as long as those states continue to hit those goals.

So, what we set off to do was to try to redraw that demand curve for reserves to try and make sure we accounted for these things like uncertainty. We did it a little bit differently from how ERCOT did it, but the concepts still all hold constant between the two. We looked at three years' worth of load forecasts, solar and wind forecasts, and then the expectation of generator failure over that same three-year period. We took five-minute observations for each of those data points over three years. We summed them up for each observation and made sort of like a time series in order to create a net load error. And then we calculated that distribution, based on the average error over that three-year period. And so, that really forms the function for this new reserve demand curve. The concept here is that adding more reserves to the system has value, because there is uncertainty on the system. And so, as we add reserves to the system, it helps us manage to that uncertainty on the system, so that we don't fall short of that minimum requirement that we need for NERC compliance, for reliability, those kinds of things. And so, what that will generate is a curve that looks like this. You can compare this new curve with the demand curve that we use today, is that two-step function I discussed earlier. The maximum price on that is $850 per megawatt hour. That's been in something like seven or eight years. And that was implemented at a time period where the energy market offered caps, which were about $1,000, I think, at that time. And, as you probably all know, they've all changed to about $2,000 at this point. If we take that $850 maximum price, and we apply this probability curve that we get for this net load error, what we're looking at is, what's the probability that the net load error exceeds a certain amount? And so, if you apply that $850 penalty, and you add the tail of the curve based on that probability distribution of net load error, you get another curve. So, this is just applying the new methodology with that probability distribution to the existing $850 per megawatt hour. And, again, the concept here is that if you assume the minimum requirement is just 1500, at 2,000 megawatts. there's a probability that the net load error exceeds 500 megawatts. And so, the concept is that the value of that next megawatt of reserves is the probability of needing to use it times the maximum price on that demand curve. And that's how you get that downward sloping function. Because as the amount of reserves you have increases, the probability that the net load error exceeds that amount shrinks. And so, the value of reserves declines as the amount of excess you have beyond the minimum requirement increases. And so, you get this downward sloping curve function, which I think is fairly intuitive to a lot of people. The more you have of a product, the less value it adds, incrementally.

So, we did two things here. One, is, we added the tail. The second piece is, we increased that maximum price on the curve for a couple of different reasons. One is that the energy offer cap is increased. And so, we want to make sure that the technical systems work in such a way that we don't have economic shortages where there's capacity available on the system to provide reserves, but the systems not willing to pay for it. Because, from a NERC standard perspective, the operators are always going to assign that reserve if it's out there, and we need to make sure that the market tools and the prices both reflect that. So, that's the curve we ended up filing.

There are a couple other pieces that I'll touch on, just briefly. I talked about the reserve market situation in PJM, where we have 10-minute reserve products in real time, and 30-minute reserves in day ahead. We also filed to align all of those and do a balancing settlement between all those products. The other thing we filed was this cascading model, which I think the other ISO RTO's do, so, we cascade the products and the locations for reserves. So, the most valuable reserve product can provide the sort of subordinate reserve products as well, so that the requirements are nested, both from a product perspective and a location perspective. It's not exactly what is in Doctor Hogan and Doctor Pope's model, but it's a simplified version of that, that for us is more practical for implementation.

The last thing I'll touch on is that there are some areas that I think we can still improve on in what we filed. One is the accounting for regulation capabilities. Regulation is kind of this fine-tune control system. Arguably, there's some overlap with that in the reserve supply stack. And so, how we account for those services probably can be improved from what we filed. Offers for reserves is another of these areas. In what we filed, generally, we don't allow offers for reserves. So, basically, all the offers are zero, and everything's based on opportunity costs. I think there are some times where offers are legitimate, but in order to go down that road we have to go through a long discussion on market power and how we mitigate those offers when units have market power, things like that. The penalty structure for noncompliance, I think, is something else that needs to get addressed. Currently, we use a historic average of clearing prices. We should probably do something more along the lines of a shortfall on the delivery of energy--a buy back at the real time LMP, something probably more along those lines. And then, just the review of the reserve products. Do we have all the ones we need? Are the ones that we have the ones we need? Are there extra ones? Can we drop ones? So, I think maybe a more holistic discussion on the types of products we have might be warranted at some point down the line, while we try to hone this design.

Speaker 2.
Good morning, everyone. What I'm going to talk about is scarcity pricing in ERCOT. We are the only energy-only market in North America, unless Alberta changes their mind. Our system-wide offer cap is $9,000. Our Value of Lost Load is also $9,000. Our demand peaks in the summer. And one thing I want to stress is that almost half of our summer peak is residential air conditioning load. Natural gas is our at the margin fuel, like everywhere else. And our scarcity pricing mechanism is based on the Operating Reserve Demand Curve that Doctor Hogan introduced, I guess around 2012-ish, and we implemented it in 2014. ERCOT does not have a mandated planning reserve margin. We have used to have a target planning reserve margin, but since we couldn't achieve it, we kind of changed our [LAUGHTER] way of looking at it. And we monitor what is called a market equilibrium planning reserve margin and the economically optimum reserve margin. And the latest study that Brattle did says that the market equilibrium reserve is about 10.25 percent, and the economically optimum reserve margin is nine percent. And our latest predicted number on the

planning reserve margin, going into the summer, is 8.6 percent. So, it's going to be an interesting summer. Maybe not so much, because the weather has not been that hot.

We are seeing continued trends of retirement of thermal. Last December, a coal plant retired, and our reserve margin dropped down to 7.4 percent, and then recently a gas steam unit combined cycle got started up again, so we went up to 8.6 percent.

We have persistently low average energy prices. We had the summer from hell in 2011. We have not repeated that kind of extreme weather so far, and there have been relatively low prices.

We don't have any active demand response, and I'll come to that later. There has been growth in retail passive response. And we see that impact when the prices go high, but we don't know exactly what the potential is, because we really haven't had high prices. We've had some, about 10 minutes until last week, I think, of prices at $9,000 since 2015. Last week we had two and a half minutes of high prices, but this is not because of true scarcity. We lost telemetry from a fleet of generators, and our real-time system thought that we suddenly lost a whole bunch of generation, and the prices spiked up. The operators caught it really fast, but for two and a half minutes, the prices were at 9,000. Our last energy emergency alert was in 2014. So, we've been lucky. There's been a lot of luck in our situation for the last couple of months, with those very low planning reserve margins.

Turning to recent events, in mid-2017 Doctor Hogan and Doctor Pope submitted a paper to our commission. (By the way, we are not FERC jurisdictional. I guess everyone knows that. We just answer to the Texas PUC.) And Doctor Hogan and Doctor Pope made a bunch of recommendations. One was for improving the system of price formation, adjusting our Operational Reserve Demand Curve parameters to account for the intermittency risk of renewables and the tax subsidies. They also suggested adding marginal costs for losses to the day-ahead and real-time. We don't consider marginal costs of losses. And there were other improvements suggested on the locational scarcity pricing, and also there was a suggestion that we revise our transmission planning criteria, and how we do cost recovery for that. And what we have done since then is, when we do the accounting for how much reserves we have in real time, we've removed any ERCOT-directed actions (we call them "out of market actions") from the available reserves. We just discount the reserves by that amount. And then, in the beginning of this year, it's been pretty busy. The PUC directed ERCOT to make some changes. The value of the mean ORDC is based on statistics on the net load error, or expected deviations in the net load. And they asked us to adjust that mean, and not change some of the other parameters, and they also directed us to implement real-time energy and ancillary service co-optimization. We don't have that right now. We procure ancillary services in the day-ahead market and it generally is sort of physical, and they just provide it in real time. There are a couple of policy issues related to the real-time co-optimization that are at the public utilities commission, because the general feeling was that, if it was just left to the stakeholders, they wouldn't get any consensus. And so, some of the stuff was left at the public utilities commission.

The other big change that happened in February was we revised our AS (ancillary services) product set. And so, coupled with this, we're in for a pretty busy time in the next year or so, just getting the rules done.

So, I'll give you an example of another thing. So, this is our demand curve. If you look at it, the price is pretty high at $9,000. That's our Value of Lost Load. The dashed line that you see over there is the way that it looks for online reserves before we did the shift. And what we had before was that for the ORDC, the statistics were gathered in seasonal four-hour blocks. And what the Commission asked us to do was to blend it all into one curve for the whole year and update it seasonally, based on the new statistics. The blending itself had kind of a similar impact as changing it by half a standard deviation. So, you will see, the blue curve over there is what it would be starting in 2020. And it's a pretty good shift. We'll have to see what an impact it has.

When the Public Utilities Commission made the change, they talked about the declining planning reserve margin. They didn't really talk about uncertainties or the federal tax subsidies. So, it kind of looks like they were not only looking at the short-term efficiencies, but also the long-term investment drivers, and how to make ORDC one of them. I found it quite interesting that when they decided to change it, they were only talking about the planning reserve margin.

Our current regulation framework is really three products. Regulation, responsive reserve, and non-spinning reserve. The responsive reserve is really like governor response. It's frequency sensitive. And we've unbundled that that into a true frequency response product and a 10-minute product. And we think that this is going to improve our reliability, as the generation makes changes, because if we get more batteries they could go into something called the fast frequency response. What our experience has been is that having batteries providing regulation services doesn't really cut it. And our regulation requirements had been dropping, so there's not much of a market there for anyone to make money off of it.

Now I'm coming to the other piece. In the PUC's directive, they directed us to implement real-time co-optimization. This is the ERCOT staff plan for that. We'll have to go through the stakeholders, and they will have their own opinions. But our proposal is to divvy up the current ORDC curve into the different products and have separate demand curves on the different products. One thing that you might notice here is that we don't have an implicit cascading of AS (ancillary services) products. It's done by the AS offer structure itself, where a market participant representing a resource can submit an AS offer, and he puts in a price for the individual products, and that kind of links them. We call it a "linked AS offer." So, that is offered. Megawatts can be divvied up among all of these four products.

The other pricing issues that are in the stakeholder process at present have to do with the mitigation of the reliability out of market actions that ERCOT takes, including Reliability Unit Commitment (RUC) actions. And one of the recommendations of Doctor Hogan is to kind of look at how we mitigate RUC increases. Right now, if we think they have market power, we mitigate them down to their incremental costs. And right now, there has been some sort of agreement in the stakeholder process to change that to include the startup and minimum energy costs into that. There were some other thoughts of making sure that the RUC mitigation puts it at the energy market offers. But I think people are tending more towards incorporating the startup and minimum energy costs.

We also are talking about mitigation of automatic reliability must run resources. We don't have any of these right now. There is a difference in opinion. I was kind of thinking that they could do the same thing, incorporate the startup and minimum energy costs, but our market monitor, I think, wants to put it at the energy market offers.

The third possible change is, when you take an out of market action, what is the locational price impact? So, we do have a pricing run when we do an out of market action, but that only provides system-wide adjustment to the price. Doctor Hogan suggested a change where we kind of tighten the transmission limits for the load limit of the out of market action resource. It will reduce the transmission limit by that much a month, multiplied by the shift factor. We are thinking of a slight modification, where the penalty price for that duration is reduced from our standard transmission penalty cost. And I like this a lot. The implementation is easy, it's transparent. You can figure out what happened after the fact, if there's any kind of dispute. If you lowered the transmission penalty for the amount that we have tightened the transmission limit, we may not have too much of oversold day-ahead market condition hedges. That's one of the drawbacks of this method. You might end up with some uplift, because of the day-ahead condition hedges that might be oversold, typically, on this kind of thing. And we are planning to use this in the dispatch run. So, there's going to be a little bit of a less optimum dispatch, but the advantage of this is that there is no uplift. Uplift is a four-letter word in Texas. So, I think they might be OK with a little less optimal dispatch to avoid any kind of uplift.

So, what is the future outlook? We are seeing low prices most of the time, with very brief periods of scarcity pricing. It's kind of like a binary pricing scenario. And in ERCOT especially, when prices go high, they go very high. Because our system rate offer cap is $9,000, and our balance penalty curve is $9,000. We're getting more wind and solar. That's generally going to depress prices. We are getting battery storage resources. Currently, we have about 3,500 megawatts of battery storage in our interconnection queue. We don't know how much of that will happen, but because they're so fast, they could reduce the transient price spikes. We're getting in increasing amount of distributed energy resources. In ERCOT, it's kind of a little bit different. When people talk about distributed energy resources, what we're getting is natural gas fired DERs. So, there is a little bit of a difference, I guess, when we talk about other places where they have more renewables, solar, primarily. For us, we have maybe almost 1,000 or more than 1,000 megawatts of natural gas-fired distributed energy resources. They're mainly co-located with the load. And they provide the additional benefit of demand charge reduction. And they also are very fast. We have seen them respond to price spikes. They're passively responding to price spikes, and they can, in subsequent intervals, reduce the amount of price spikes we have. Small scale solar is increasing, but not near the penetration levels you see in other places, because there are not state incentives for that.

Passive pricing, like I said before, is growing. We have a very robust retail competitive market, and even for the non-opt-in entities like the munis and co-ops. You know, they give out free Nest thermostats, but they kind of say, "Hey, we'll be able to reduce your consumption by bumping up your air conditioner's temperature setting." So, we have a lot of that, and we are not sure how much of it is there. We don't know exactly what the total potential is. We tried, and we have failed in enabling active demand side resources. And the reason is that we have low prices. The scarcity pricing intervals are not that long in duration, so there's lack of incentive. The current rules for active participation have strong compliance metrics. But one of the key things is, we do not follow FERC Order 745. So, if a load resource participates in our energy markets actively with bids to buy, they only get the benefit of avoided consumption charges. They don't get paid anything. And, of course, we don't have a capacity market. We have something that's caused a lot of heartburn among a lot of market participants called Emergency Response Service. It's a capacity market for demand response only, that takes away everything from active participation in real time price formation. It's got about a $50 million cost cap per year, and there's a lot of participation in that.

So, other ideas? If you look at our firm load shedding procedure, we have to think about it, because, with extremely low reserve margins, we have to say, "Hey. What can we do?" We are going to go into firm load shed if you get a hot summer, most likely. I mean, I think that across the U.S., the firm load shed procedures have not change in decades. The controlling entity, the ISO, will tell the transmission service providers that this is how much load they have to shed, and what the transmission service provider does is they disconnect feeders, and if there is a feeder that's marked as critical, because it's serving traffic lights, hospitals, or there's someone downstream from that that is on a medical kind of device, they don't shut that. But now, we've got a full deployment of smart meters all across Texas. And they have remote disconnect and reconnect features. And could it be possible to use that feature, given that you can have a fast enough response time, to do a surgical load shed. We tried that out. We asked Center Point to do that, and they could do that, but one of the problems is that when they want to reconnect, there's about maybe two percent to three percent failures in reconnection. And what that means is that they have to roll out a truck to each of these locations to reconnect it. So, if you're disconnecting maybe 50,000 residential customers, and two or three percent cannot be reconnected after the event is over, that causes a problem. It's expensive. But I think technology can improve that. So, what does this do? You won't be in the *New York Times* or the *Wall Street Journal* if you can do the surgical firm load shed, if there is a little bit more knowledge that you're disconnecting folks who may not care that much. In the future, maybe in the recovery areas you might be able to have a reliability service as part of your deal with your local provider.

The other one is ancillary services. We have made a good start. I think ERCOT is in a comfortable spot with the change, but here are a couple of other ideas. When we look at our dispatchable resources, we don't pay for inertia, and maybe we need to get to that point at some point in time. The other one is availability. And that has connotations of a capacity market, so I won't say anything more on that.

Speaker 3.
Good morning, everybody. It's a pleasure to be here. I have to say, when I first saw the title that Bill sent for the panel, I read it differently. I thought the causality arrow went from left to right, which is to say, the surest way to create stress conditions in a room full of market participants is for the RTO to announce a major market reform. [LAUGHTER] Nonetheless, that doesn't seem to stop us in the slightest. As some of you may be aware, New England is in the midst of a fairly substantial transition to a renewables- and gas-based system. That has a lot of promise. It's likely to bring us to a much cleaner and greener energy future. But it also is creating a lot of new challenges. And what I'd like to do is share with you today our thoughts on why that is the case, and where we think we need to go with it.

Since we're all gathered in the Red Sox nation, I thought it would be useful to give you a little context. Twenty years ago, approximately 40 percent, 22 percent plus 18 percent, of all the electric energy produced in New England came from power plants burning oil and coal. Last year, that was down to one percent each. Almost zero. On the national stage, there are debates about saving coal. In New England, the coal power plants are a pile of rubble. They are gone, with one or two small exceptions that are very old and don't run very much. Much of that has been displaced by natural gas in the shale revolution, and it's now reaching 50 percent of all the electric energy we produce in New England. Looking forward, what's really coming and will dramatically change things further are the renewables. The top left shows you the growth in solar, current and projected. Let me note, for those of you who for whom this may not be obvious, New England is not like California. It's not like Arizona. It's what we diplomatically call "latitudinally challenged," [LAUGHTER] when it comes to solar production. And for that reason we have lagged a bit behind California, despite similar incentives. Ten years ago, we had essentially zero solar, behind-the-meter as well as commercial industrial scale solar. Currently it's about 3,000 megawatts. We expect it will more than double over the next 10 years. Currently, by nameplate, that is reaching 10 percent of our systems capacity, although it is less than a tenth of that in terms of energy, because of our aforementioned geographic challenges. What will really change things, however, is the wind. Our interconnection queue is staggering in the amount of resources that are seeking to interconnect, and the majority of that is now wind. Included in that 57 percent figure is all of the offshore wind that is in the process of being developed, and there is much more likely to come behind it, and that will really change the nature of our system, going forward. All that, from an environmental standpoint, probably is very promising. But, as I alluded to, there are challenges, and many of these have been exposed best during cold winter conditions in the last two or three winters.

To highlight a little bit about how we see things, let me note that in New England, the natural gas fueling half of our energy comes almost entirely through pipelines from the West, many states far away. There have not been material additions to the number of pipelines into our region since I was in diapers, and maybe before that. I'm not that young. The challenge is that these pipelines are unable to deliver fuel to many of our region's new power plants when it's cold weather. And that's kind of insane, when you think about the fact that we have billion-dollar power plants that sit idle when we need them the most.

The chart you see at the bottom left is a daily chart, running from December 25 in 2017 through January 8th. That was a roughly 13 to 14-day cold spell in New England, more than a year ago. And the height of the blue bars shows our estimates of the total amount of gas-fired capacity that could not get fuel to run, because there's not enough pipeline capacity to bring in the fuel and to reach them. Those numbers are very large. The 4.6 you see at the left is getting close to one half of the total gas-only generation capability in the entire region.

Now, the hope is, if we have all these new renewables, and they all steadily produce a consistent high level of energy throughout these cold spells, there's not a problem. But, as you can see from the top left graph, to date, that is not the case. The purple line shows you the aggregate production of all of our wind resources, system-wide, in New England at a sub-hourly frequency, over that exact same period. And what you notice is that there are days when the wind is blowing very well, and those resources are producing to 60 to 70 percent of their nameplate capacity, which is outstanding, and way above wind design average. But there are also many days when it plummets to very low levels, approaching zero. And this really creates a whole new world of potential stressed system conditions, going forward, because, when those times line up, and we have cold periods for an extended duration, when much of the gas fleet cannot get fuel, and at the same time, in the aggregate, our renewables fleet is approaching zero production, we are surely going to see a lot more stressed system conditions in the future.

For that reason, the topic Bill teed up for us, of how do we adjust pricing, becomes all the more important. I should note, for the record, that solar production would exhibit a similar property to this.

Now, let's talk about markets. If you were an economist from Mars, and you heard the first part of my talk, you might say, "What's the problem? When markets get very tight, prices rise quickly. Demand will fall accordingly. Supply may increase as much as it can in the short run, to the point where supply and demand balance, and all is well." And that is, of course, what we would like to see. The problem, of course, back here on Earth, we do not have a lot of passive price response of demand resources in our corner of North America. We don't see that happening. And the root cause is because consumers fundamentally don't face real-time prices.

I would be remiss to come to a session on market reform for stressed conditions and not note that real-time pricing is probably the most cost-effective long-term solution to this whole issue. You don't need everybody. You just need a little bit of demand to face the appropriate price in stressed conditions and respond to it, to line up supply and demand and let us run the system much more smoothly. My former advisor, Severin Borenstein at Berkeley, likes to point out that if you dig deep enough into electricity market design challenges, the root cause at the end of the day of almost everything in our markets is that consumers don't face the real-time price. You talked about that yesterday, so I won't belabor it here.

What I do want to do is segue to my second point, which is that, today, and when we do scarcity pricing in wholesale electricity markets (which is done differently, as you've noted, in different ISOs), we don't yet emulate the outcomes in that first process very well. And I wanted to highlight that. I think there are two reasons for this. One is the reason I noted there, which is a problem of information. We don't actually know the true marginal consumer's willingness to pay, so we can't set prices exactly that way. The other issue is that, even when we can estimate it using expected value of lost load, we don't actually implement that very well. Or, at least, our practices vary widely, and I'm going to come back to that point.

Before doing so, however, I want to highlight the question I've teed up at the bottom of this slide for this group's discussion. In the *precis* for today's session, many of the questions related to stressed system conditions, but it didn't actually tee up the question of what should be the goals of market reform for stressed system conditions. I think many in this room would probably agree that letting customers experience real-time prices would be ideal, but let us imagine that we don't have that, at least for the time being. An ISO certainly can't do much about that, because it's a retail function. So, what should the goal of our stressed system pricing really be? I would be particularly interested to know if there's a divergence of opinions on that, because I have to make a filing on this in several months, and I'd rather know now than then, what people might say.

Let me now turn to a topic that this particular conference has dealt with extensively in the past, although I think not recently, which is, how do ISOs and RTOs do this today through ancillary services? If you aren't steeped in the details of how electricity market design is done, you might think ancillary services is this little wonkish thing that nobody but the PhDs understands, and it's an asterisk on the design of energy markets. ERCOT, oddly enough, calls itself an energy-only market. I think it's really an energy and ancillary services market, and, actually, I put the ancillary services first, because that's actually more important, in terms of the market design. They're hugely crucial to how everything works, not just because they're crucial to being able to run a power system reliably, but because they are how, actually, we generate revenue response to scarcity in practice. That is derived from ancillary service design. Here, I'll give hats off to PJM's efforts to advance this, and of course kudos to Bill for many years of trying to press this on us. My point here, then, is not to review what's been done in the past, but is actually to point out that there's a lot to be done ahead.

The theory of operating reserve demand curves and this general design of ancillary services is very sound, but it's not complete. So, in the interest of thinking about where some of these areas need to be moved forward, I'm going to note three points. First, we have spent, collectively, a lot of time thinking about the slope and structure of demand curves for ancillary services. I think there is a more fundamental question, which is, actually, are we buying the right products? For a long time, ISOs and RTOs bought a set of very standard products, which were 10- and 30-minute fast ramping capability, designed largely to handle the sudden electrical separation of large things like nuclear units or large coal units. That's still needed, as long as those resources are around, but the question is, are those enough products to handle the changing grid and the new fleet of renewables we have coming in? We think the answer is no, as I'll discuss on the next slide. We need to buy new products.

Number two, should the design of ancillary services and their demand curves be fundamentally based on the value of lost load or our best estimates thereof, or should it be based on what I will call "noneconomic" reliability standards? I used the word "noneconomic" not normatively, but descriptively. They were created at a time when nobody paid attention to the kinds of things Bill has taught us since. My point here is that you will get very different answers depending on what you do. These are not going to give you the same outcomes. And what we have today is a very awkward hybrid of the two. So, when you look at the pictures that the previous speakers have shown you, you sort of see this giant block at a very high price that doesn't look anything like a demand curve. And then there's this sort of economic appendage, like the tail, going all the way out here on our lizard that's trying to deal with this block of stone that it can't get over. That is this awkward hybrid of a reliability standard rule that had no grounding economics as a descriptive statement in its development and an effort to bring more economic logic and probability calculations on value of lost load into it. This seems to be the practical implementation. Surely, this is not the right answer for the long term?

Last, for those of you who think we know everything, there are areas we still haven't figured out. Proper reserve scarcity pricing should be nodal. We see this today, when we're carrying reserves, like 200 megawatts of online reserves on a generator, and we know that if the contingency we're most worried about happens, the network right against it will be constrained, and that generator will not be able to turn its reserves into energy post contingency. If that's the case, the proper ex-ante, pre-contingency price for those reserves at that location is zero. That will not happen today. That's not how the designs work. But in order to keep us employed, we keep pointing this out to our bosses. This is not a simple problem. To actually do this correctly, you have to know, for every possible location you may carry reserves for, what will be the flow of power in the post-contingency state on every element? In our network, for example, we run 4,000 to 8,000 possible contingencies every few minutes that we're checking. Four thousand to 8,000 times every possible place. You're in a combinatorics sort of space. So, this is a very difficult thing to do. However, I think it would be remiss of us not to note that nodal reserve pricing really probably is crucial to getting the prices right, not just in theory, but in practice, because resources get compensated for reserves that we cannot use. And, by the same token, others will be undercompensated for reserves that we would like to have more of, locationally.

I'm going to turn now to what we've proposed to our stakeholders recently. We've been motivated by the urgency to address these problems by the facts that I showed you earlier--the gas and the fuel supply limitations we face, and the rapid growth in renewables. Also, by a not so subtle kick in the butt from the FERC to do something about this quickly. We're proposing to create three types of reserves in our day-ahead markets. They are mostly new. And one of them is just a change from what we do today, and I'll walk through each of them with you. The first is to create a new type of reserve, a new type of ancillary services, called "replacement energy reserves." This is essentially energy that we expect to be on call during the operating day, with a delivery time that's on a multiple hours timeframe. It would be cascaded, and there will be different time requirements. Some of it we would need within about 90 minutes, and the rest we would need, probably, within about four hours. And the main reason for having that is it serves a variety of purposes which we meet today using largely out-of-market commitments, sometimes in a panicked form and sometimes in the form of worries about what might happen the next day. You don't need reserves on a few second, or a 10-minute, timeframe to manage wind. It doesn't change that fast, at least not that fast in New England. 90 minutes is great. So, that is a much less costly way to do it than buying lots more 10-minute and 30-minute reserves. We have problems when generators get committed, and when something unexpected happens to the use of natural gas, and they call us back within the hour, and they say, "I cannot get gas." If we can get something else within 90 minutes, or four hours, we're in a much better place to manage those unexpected surprises. We don't think any generator wants to be in that situation. They don't generally know it. They often feel like everything is lined up, but there can be pressure problems. There can be other issues, where they can be challenged in ways that they don't anticipate. There can be time delays as resources switch to dual fuel, which is crucial in New England in the winter. Units have to come down. They have to drop their load. It takes time to flip back over and come back on oil. You need to be able to cover the energy and balance during that period. Those are rarely known in advance, so you need stuff that can move quickly. And last, but not least, we have to be able to restore the contingency reserves. If we lose a major non-gas resource like a nuclear unit, or like an interface to another area, we will use our traditional 10- and 30-minute reserves, and we'll be able to balance the power within 10 to 15 minutes, and we'll be fine for about 90 minutes, but then existing rules require us to restore those reserves, which means turning all those resources back off. And now you have an energy gap, and you've got to fill it. And you've got to fill it on these multi-hour timeframes. We don't presently give an award to resources, or a binding financial commitment, to have that capability, and, not surprisingly, when we call the resources we need out-of-market to do this, they say, "What? I wasn't expecting to run today. Give me a couple hours to get fuel." I'd rather give them a binding financial award, with the obligation to be there on standby on a very specific timeframe and put substantial skin in the game in the contract they get awarded on a day ahead basis, so they know what's expected of them and they have financial repercussions, where those financial repercussions closely line up with the actual cost, the real time spot price that we're posting at the. In our markets, as you know if you run a power plant, the marginal incentives can get close to $9,000. Very strong incentives. That's really the biggest new thing.

I want to point out load balance reserves. Today, the day-ahead market can clear demand much less than what we forecast. We have an obligation to meet the forecast, and essentially provide inventory, or liquidity, to the market in real time. That is done through out-of-market commitments, usually in the reliability unit commitment process, which we call a resource adequacy assurance process. That tends to suppress prices and undermine the incentives for resources that we may need to actually go out and arrange fuel. We're going to create a new reserve product, which we establish in the day-ahead market, for the gap between cleared demand and forecast demand, giving them a financial obligation to be available for designated hours, and to start up and be ready to run then, unless, of course, we tell them, "Load forecast is off, and you're not needed." Last, but not least, the traditional reserve products we buy are generation contingency reserves. Here, we'll continue to buy the same products, but we are going to change how those awards are made and how they are settled in the day-ahead markets, because we've identified a way to strengthen the incentives for their performance by doing so.

Taken together, all of these products, and the incentives we're going to create to be able to fulfill their obligations on the timeframes that we would like to have this service, are designed to create a new margin for uncertainty, much greater than what we have today, so that, as uncertain events unfold, like the constraints in the pipelines are much more severe than we expected, or the variation in the wind and the solar is much worse than we expected, or, worse yet, they all happen at the same time, something traditional power systems has never been designed to handle…

We're in a world of correlated adverse shocks. You need a much bigger margin in that world. I noted that these changes provide stronger incentives. If you're interested in the details of market design, one point that you'll be interested in is that we're structuring all of our day-ahead ancillary services as real options, and I mean that in the precise sense of real option theory. There will be strike prices. They are options. You are giving us a call option on energy the next day, which we can call for any purpose or no purpose at all. Of course, we will always do it economically in real time, based on your standing real-time offers, in order to achieve the least-cost dispatch. What this does is it means that if you cannot provide energy at the time, you are buying out your position, because you cannot cover. And what you're buying it out at is, then, the prevailing real-time price, which is exactly the correct cost of your nonperformance. That might be only $100. If it's a $40 day, and you're not there, and the price only goes up a little bit because you're not there, that's fine. That's the right price. It might be $3,500, and it might be $9,000, if we're at a true scarcity condition, with pay for performance. And we want the generators to internalize that risk and those costs and therefore decide exactly what is the cost-effective investment. Is it cost-effective, given the size of the resource, for them to add dual fuel, for them to do additional option contracts, for them to buy LNG in advance before the winter, and all the other things that could be done? It's technologically feasible, but it's not commercially viable, for the generators in today's market with today's design.

I'm going to close with a note that we're also proposing to create multi-day-ahead markets. The context here is that, for most of the power system's operational history, operators worried about operating today and having a clear plan for the next-day operation, and we created markets 20 years ago. We created real-time markets and day-ahead markets. Today, looking one day ahead is not enough. On the operational side of ISO New England, we are doing everything six days forward, continuously. We forecast loads six days forward. We forecast pipeline flows six days forward. We forecast outages six days forward. We line up internal models of generators likely scheduled six days forward, and we tell them when we think that three days from now it's going to be more important for them to run than today. But of course it's not binding. Our markets do not align with that, and the price signals that go out one day ahead can often be misaligned with what resources we expect we may need three or four days ahead. That discordance is a growing problem. You have to align the markets with the operational horizon, and in a system like New England, which is out there on the edge of stressed fuel security conditions, and with the influence of renewables swinging our system, we've got to align the two. What we are in the midst of discussing with our stakeholders, specifically, is creating a rolling six-day-ahead, effectively a 144-hour multi-settlement, market. Instead of running tomorrow's market for a 24-hour period, we go and change the software to go from 24 to 144 hours, with binding awards for 144 hours and binding settlements. But then, every day, we re-run it, and re-establish new schedules, new prices, and settle on the deviations. Instead of settling on deviations from real-time, you settle on successive deviations in every position. If you've worked in commodity markets, you go, "This is obvious. This is how all commodity markets settle." And it's actually really not a new thing at all. It's just new to the industry, because in the past there was just not the need for this alignment the way there is today.

So, with that, I want to leave you with a note that if you would really like to know the details, we have a lengthy discussion paper that goes through a lot of the design details, with numerical examples on a lot of the economic theory and practical implementation considerations driving all of our work on this. As I noted, we're discussing it with stakeholders and we will be filing a substantial portion of these proposed design reforms with the FERC on October 15th, this coming year. Thank you so much for your time today. It's really been a pleasure to have the opportunity to share a lot of these ideas with you.

Moderator: Thanks to the first three speakers for giving us a perspective from three of the largest US RTOs, but as we know, this issue is something that's not only happening here in North America. Our colleagues and friends in Europe are facing this as well, and we're pleased and thank Speaker 4 for making the effort to be here to share that perspective.

Speaker 4.
Thank you very much for the kind introduction, and thank you very much, Professor Hogan, for the opportunity to present here. It's a very exciting opportunity.

So, this short presentation is structured into two parts. I'm not assuming that you are familiar with European electricity markets, so I'm going to try and give you, for the first half, a bit of the 10,000 mile view of how we are organized, and then talk about the European Commission considerations regarding scarcity pricing and ORDC, as well as the progress that we've been making in the Belgian electricity market.

So, the way I'm going to present the European market is related to the specific considerations that have to do with scarcity pricing. But first just so you get the big picture of what our system looks like, I've borrowed a slide from a presentation of my former advisor at Berkeley, where he depicts the way US electricity markets were organized around 2005. So, if I had to pick what pattern our current European market most closely follows, it's the California pre-2001 electricity design. What's most interesting about this design is the separation between the power exchange operations and the system operator functions, and this complicates scarcity pricing. I'll talk about that more in a few minutes. So, that's the first thing that stands out. The other thing that is interesting to note is that we run a day-ahead energy exchange which applies zonal pricing. There are institutional reasons why this is happening. I'm going to comment a bit, momentarily, about where we are going with this. And the part of this that is very important regarding remuneration of flexible capacity in the form of ORDC, is the way our real-time market operations are conducted. And, for me, also, this is probably the one major challenge for European market design, moving forward, because a lot of the action is moving closer to real time. The way to properly remunerate flexible capacity is by dispatching and pricing properly in real time.

So, the current status in the European electricity market is that we have this notion of balancing responsible parties, which are, in fact, encouraged to maintain the balance of their perimeter as they approach real time. The second important player in this cycle system is balancing service providers. So, these are entities that are offering reserve services to the system. So, they are expected to deviate from former set points in order to help with balancing the system in real time. So, there's this notion that BRPs should do their best to keep their balance within their perimeter at real time, and rely on BSPs to be activated upward or downward to deal with any residual imbalances.

One thing that is very interesting about the central European market is that we don't have a real-time market for reserve capacity. By that I mean, we definitely don't have optimization of energy and reserves in real time. But on top of that, we're not remunerating deltas in real-time available reserve capacities. That, I believe, makes things complicated, in terms of how you do proper remuneration of flexible capacity in real time.

So, that's the high-level setup. So, this is the part of the market where the separation between exchange and system operator is relevant. We have the Price Coupling Regions (PCR), which is a project of European power exchanges to create a single day-ahead price coupling solution. So, we have multiple power exchanges, and they are all assembled under the PCR. The PCR is running on the market clearing algorithm which has been developed by our university. It's called the Euphemia. And the request that Euphemia accommodates, among other things, is to affect zonal pricing. So, there are also deviations from how things are done in the US, regarding how we deal with non-convexities of cost. That's a separate discussion. Regarding zonal pricing, there are some interesting developments going on in Europe. One thing that has been attracting the attention of regulators, system operators, and other stakeholders is the sharp increase in congestion management costs. So, Germany, a couple of years back, stacked up a half a billion euros of congestion management costs, and that has generated some debates about the effectiveness of zonal pricing in Europe. There has been a recent shift in the center Western European region in how we represent the network. So, there's this whole discussion about the differences between the former transportation model that we had, which was referred to as the Available Transfer Capacity Model, and something that's getting closer to what the physics really look like, which we call the Flow-based Market Coupling Model. However, this is still a zonal model. So, there's still a lot of discretionary freedom amongst system operators about deciding on how much country to country aggregate capacity they make available to EUPHEMIA in the day ahead. And the tendency's to not make too much of it available, because if you make too much of it available, then that causes some scrambling in real time, to deal with congestion management.

So, that discretionary freedom of the system operators is also generating significant discussions as it relates to flow-based market coupling. And what I find surprising, at least with discussions I've had with stakeholders, is that where it's actually receiving less attention is in the area of sending the right investment signals in the right places, and gaming.

I showed you earlier that we resembled the California pre-2001 design. The natural thing to ask is, so, what about the DEC game? And what I understood a few weeks back is that you cannot do a DEC game, because the way dispatch is done is cost based. But then the argument goes that if you want to go to nodal, that's not a market-based solution, but you do redispatch on a cost-based basis, which means that the regulator has pre-computed, during dispatch, costs, and bids them in for you. So, there's a bit of a logical inconsistency there, which I think is coming up more clearly as the discussion is advancing.

My understanding is that discussions around nodal pricing used to be taboo in Europe. They are not, as far as I can tell, since I've been there. So, the concept of zonal pricing has increasingly been challenged. There are some system operators, including the Polish system operator, who are looking into the possibility of deploying nodal pricing.

Regarding real time operations, I think the things that are interesting to be aware of is that the king in real time is the TSO. If the king in the day-ahead is the power exchange, the king in real time is the transmission system operator. So, what happens is, the whole operation is passed over to the TSO through nominations. That is, I, as a utility, have been cleared in the day-ahead power exchange for my portfolio, as well for as offering reserve through this notion of BSP's, and then I tell the TSO, "This is what I'm planning to do with every one of my generators for the next day, for every hour." So, on/off schedules and set points. So, the TSO checks, is what has been cleared for me in the day ahead consistent with what reserves that utility has promised to offer me in the day ahead? And things move over to real time.

Once things move over to real time, the relevant question is, what degrees of flexibility does a system operator have to decongest the network and balance the system? One thing that is very interesting, as a point of comparison with the US, is that European system operators really like topological changes. It's a very cheap way to decongest the network. This is a stark difference between how things are done in the US and Europe. And then there are two other lines of defense for the system operator. One is free bids. These are generators that just showed up in real time. They happen to have some free capacity available, so they are made available to the real-time operations, and then there are the BSPs that I mentioned earlier, which are reserves that had promised, from the day-ahead, that they would be there for the system operator to use.

Now, what I mean when I say that we don't have a real-time market for reserve capacity, is that, when we activate reserves in real time, we're only paying them a for the marginal cost the resources are incurring for fuel. We're not paying them for any changes in available reserve capacity, which makes scarcity pricing problematic. Two initiatives that are also interfering with the intent of introducing scarcity pricing in Europe are the moves towards integrating our real-time operations. What we're doing currently is, every TSO is activating their own resources within their own zone, within their own country, within their own perimeter. There are two projects going on called PICASSO and MARI, where the goal is to co-optimize the activation of reserve throughout all of the European balancing area. So, that's something that will come up in a few minutes.

Regarding the developments in ORDC scarcity pricing, the high-level picture here is that scarcity pricing is viewed favorably by the European Commission, because it's seen as a way to harmonize the operation of the common European energy market. So, what we have currently is a diversity of capacity options, capacity payments, as well as something that we call strategic reserve (this is gas units that were going to be mothballed, but we're paying them every year to stand by for the winter, in case they are needed).

There are these three major ways in which European countries are dealing with resource adequacy, and this diversity is viewed by the European Commission as hurting the initiative to move towards a common integrated European market. So, on top of that, capacity mechanisms are receiving scrutiny as ways for countries to pick winning technologies through state aid. So, there are two indicators in legal documents that have come out recently. They're revealing a favorable view of the Commission towards the notion of ORDC and scarcity pricing. Those are the Electricity Balancing Guideline and the Clean Energy Package. And I've cited the relevant text from each of the two. So, in Article 44, number 3, of the European Commission Electricity Balancing Guideline, you read that "Each TSO may develop a proposal for an additional settlement mechanism separate from the imbalance settlement, to settle the procurement costs of balancing a capacity pursuant to Chapter 5 of this Title, administrative costs and other costs related to balancing. The additional settlement mechanism shall apply to balance responsible parties. This should be preferably achieved with the introduction of a shortage pricing function," which is another way of referring to scarcity pricing, and if they choose another mechanism, they should justify, well, why they didn't go with shortage pricing.

And then there is a reference in the Clean Energy Package, Article 20, number 3, which refers back to the text of the Electricity Balancing Guideline, where it's asked that member states should, "in particular, take into account the principles set out in Article 3 and shall consider," among other options, introducing a shortage pricing function for balancing energy, as referred to in the text that I mentioned to you earlier.

So, these are two very important legal documents for European TSOs and regulators that show the intent of the Commission that there is a favorable view towards shortage pricing, and if you go with another option, you need to justify why shortage pricing won't cut it for you.

Regarding what is going on in Belgium, this is an effort that we started with the Belgian regulator four years ago. In September, 2014, and until mid-October, 2014, we had four of our nuclear units go out on unscheduled maintenance for one and a half months, and that represented one third of the country's capacity and it caused a lot of nervousness for the Belgian regulators regarding whether we had adequate price signals for dealing with these incidents. So, the question was posed by the Belgian regulator, what would happen if we introduced ORDC to Belgium? So, what we did is we conducted a one-year study for the regulator. We developed the bottom-up model of how the Belgian electricity market functions. Our first finding was that CCGTs are making losses with the current environment. They cannot recover their investment costs, and we found that the ORDC could overturn this and allow them to recover their fixed investment costs. And this created some interest in the regulator for the design, and, in fact, Professor Hogan came over in 2016 to a workshop that we held together for scarcity pricing in Brussels with the European Commission, and to some extent the text that you saw earlier benefited from Professor Hogan's contribution in that workshop. There were follow ups in 2016, kind of like a sensitivity analysis. So, what will happen if we have the nuclear come back, and this 2014 problem goes away, will they add or go away? What will happen if we change the VLL? What will happen if we do monthly auctioning, or a day-ahead auctioning, of reserve capacity? Some detailed questions like that.

And then, in 2017, the question became much more real, in the sense of going from a model and then an academic exercise to actually proposing, OK, what do we actually need to change in our market rules if we wanted to make this happen?

So, there were three major questions that were put on the table. The first was, do we need a market for real-time reserve capacity? The second question was, do we need to do optimization and day-ahead between energy and reserves? In what I showed you earlier, in the day-ahead, the power exchange is king, but it only trades energy, and in some way transmission capacity. But there are separate reserve auctions, either before or after the energy exchange, and the question was, do we need to introduce reserve as a product in the day-ahead exchange and co-optimize it with energy? And the third question was, do we need virtual trading?

The first question's pretty obvious. Do we want reserve capacity in real time or not? That's what you need to get the right price signal for flexibility. The second and third questions are trickier, because that's the real time, and that's where the deltas are traded. And you need to properly design the forward markets relating to the real time to get the signal back propagated, so that you get the long-term investment signal that you need for an entity to actually go in and not only play on the deltas. And that's where virtual trading and co-optimization are relevant.

So, there are two flavors of the work we did. One is in academic one, and then there's an extensive report that talks about what needs to change in the Belgian market. But the major recommendation that we come out with is that, for the first step, it's not enough to just have an adder for energy. That will do nothing for you. Basically, everyone will reshuffle their bids, and you'll end up getting the same dispatch with the same payments, ultimately. You really need to measure real-time reserve capacity and pay for the deltas for that. So, for example, free bids, if they show up in real time when they weren't planning to, get paid for the real-time extra reserve capacity that they make available, they have an incentive to be there in the future. So, that's the major first step, and then we can talk about virtual trading, or optimization of energy and reserves, which, given the current state of the discussion, is a few steps away. But the first step is the real-time reserve market.

And then the other interesting developments were that we worked with the Belgian system operator last year on getting them onboard on this concept. So, the Belgian regulator favored this investigation. But the TSO is an integral part of the process, so we had multiple meetings with them where we explained the idea. We explained how you calculate the adders, based on the telemetry data that they have available. So, they have this thing called the Available Reserve Capacity, which measures this capital R in the ORDC formula, which is exactly what we need to compute the adder. So, this was a success, in the sense of getting them to understand the concept. It's different, with 15 minutes, whereas in the US it's done every one hour, but we're taking things step by step, and let's understand the 15 minutes first, before we go to the one hour. So, they had a report in the end of 2018 of what would have happened with 2017, but not based on academic models, rather based on the actual telemetry data that they had. So, the success was getting the TSO onboard. Maybe what could have been more exciting is if 2017 was a tight year, and we would see the adders kicking in a lot. By contrast, it was a comfortable year, and there were only a few incidents where the adder kicked in. You've seen one of these incidents, on November, 29, 2017.

So, here what we have is the total available reserve capacity system. This is the biggest spike that was observed during the study. You have a big forecast error on load, so already the system is stressed, and it's depleting its available hydro. And what you see here is the scarcity adder of 1300 Euro. One concern that I have, moving forward, is that the ORDC was not wide enough, so we were getting some behavior where the ORDC was either zero or a very high level. So, we're now entering the discussion of what the width of the demand curve should be, and putting that on fundamental principles regarding looking at this in a multi-period optimization framework, but that's looking forward.

One thing that's very encouraging is that, effective October of this year, this thing that was computed ex-post for 2017, will now be computed in real time and published online by the system operator for every one of the stakeholders to see. So, we're making some progress. And the next step in this evolution is continuing to ask these, "How do we do it" questions.

So, the last question that came up in the meeting with the regulator and the system operator, was, "OK. The idea looks interesting, but are we even allowed to do this, given that we have PICASSO and MARI, where we will be trading balancing energy with other countries? How will Belgium apply this unilaterally? What will that mean for France, that's buying power in real time from Belgium, and how they should pay for that power?" So, we're getting into more and more detailed discussions about the mechanism. So, some of the stuff you saw there is in a couple of journals, and there's this big report here, where we describe in detail what we proposed for the Belgian market rules. That's on my website. So, thank you very much for your attention.

Clarifying question 1: Speaker 2, I have a question for you. If you do firm load shedding, of the whole feeder, how long does it take to re-energize the feeder? You said something about how, for individual meters, some of them have failed, but you could do most of them automatically. But if you do firm load shedding on a whole feeder, how long does it take to re-connect? Let's say the problem that caused you to do firm load shedding went away immediately, could you immediately restore --

Speaker 2: Yep. That's the preferred approach right now. The issue is that right now, if I disconnect the feeder, it's all remotely controlled, pretty much, unless you're talking about some rural co-op or something. But when they restore it, if they have a remote disconnection they probably have a remote reconnection.

Clarifying question 2: I have a question for Speaker 3. You talked about fluctuation in available natural gas, and I wasn't clear whether it was pipeline capacity change, or that what was left over after firm reservations on the pipeline for the natural gas generators was fluctuating. See what I'm saying? What was the underlying physics of it?

Speaker 3: What I was referring to is the revelation of uncertainty, which can arise in many forms. Even if the physics hasn't changed, the participants may need redirects or other activities in the constraints they were unaware of until they seek to do the action. So, it's the revelation of uncertainty, and the physics is, get a gas expert who does gas physics. Sorry.

Clarifying question 3: Two quick ones for Speaker 3. When you showed the unavailable gas-fired resources, did that account for any of the liquefied natural gas that could be delivered from Maine, or even in through Boston?

Speaker 3: Yes. When we do those calculations, we assume optimistically that the main pipeline (if you know New England it's the M&M, which has 833k per day) is fully utilized to its max. We do those calculations. We do get information on what that pipeline is actually doing, but these calculations are done on a day-ahead basis, generally. The numbers I showed you are day-ahead projections for the next day. We also have a great deal of information about what's coming out of the district gas terminal in Boston. The one adjustment we do is, there are two (only one is currently active) offshore marine import facilities. And if we know there is no ship, we assume that that capability is zero.

Questioner: Super. And on your load balance reserves, will that largely replace their reliability commitment?

Speaker 3: Largely, which is something that, quite irrespective of its motivation in fuel security, directly at least, will go a long way to addressing a longstanding thorn in many people's sides over the price suppression of the out-of-market commitments. With the design we have (maybe you have to be an economist to appreciate this) the equilibrium is that you will never want to under buy. You'll never want to short the day-ahead market, as a load serving entity. Because you'll be more profitable if you always hit what you expect to use in real time, which is not true today, and which is one of the main reasons why load systematically unclears. It's not as bad as the CalPx 20 years ago, but it's still a chronic problem in New England.

***Clarifying question 4*:** So, I want to follow up on the individual meter reconnection issue. What's the underlying problem? Is it a communication problem, and does CenterPoint see a solution to that?

Speaker 2: We haven't heard back from CenterPoint. We're planning to follow up on that. They did a test a couple of years ago. The way that these meters communicate, it's kind of like a hop, skip and jump. It's not a broadcast. They send it to one meter. The meter communicates with the other meters, so there's a little bit of a time lag issue with that, and I think it's just a question of the reliability of the meters. Sometimes they just don't reconnect. So, there's a bandwidth issue, which I think technology can fix. And the other one is a reliability issue, and that might be a bit more tricky, because replacing a meter with something that's more reliable is expensive, but I'm hoping it will happen sometime.

Clarifying question 5: I have a question for Speaker 3. The replacement energy reserve, I thought that was the one that is probably going to replace RUC. Is it the call option to avoid the reliability unit commitment? And the second question is, how are the incentives for those assigned to the renewables, or the non-firm resources, that create that problem? I assume you created the replacement energy reserve because of the availability of the renewable resources. And how are the incentives assigned?

Speaker 3: So, the answer to the first question is, in principle, both the replacement energy and the load balancing reserves together could replace much of the functions of what's generally called the RUC. There's a different acronym in New England. However, in practice, replacement energy today, when we need that capability, usually there is not a commitment being made in the RUC. It's made during the operating day. Because we don't know, a day in advance, that we're going to need to have that. So, in practice, it's really the load balancing reserves that will make it much less likely that we ever need to take that action. The replacement energy reserves will reduce the likelihood that we have to make commitments during the operating day that are not technically in real time, and that in fact does not have a price, at least we don't have hourly balancing markets for commitments made during the operating day. And without that, you can't get quite the right pricing for it.

I didn't quite follow the second question fully. All of this is not solely based on renewables. It's also based on things I mentioned, like the moving down on the gas units to allow them to flip over to dual fuel, and other reasons. So, there are a lot of reasons motivating the replacement energy. I don't think I'd want to ascribe cost causation to any one resource type, though that will be a very hot topic of discussion, if I know my stakeholders, when we get to it.

Clarifying question 6: For PJM, in your list of possible improvements and what was filed, I didn't see anything there about a transitional mechanism to avoid overpayment to existing commitments because of the fact that the proposal is going to increase energy and ancillary services revenues. So, I'm curious to what PJM's plans are for that big issue, for some of the people who are concerned about the proposal. Speaker 2, you obviously referred to the lower reserve margins for the summer at ERCOT. I'd be curious if you could sort of unpick how much of that is a transient issue because of the surge in demand in West Texas from Permian Basin Oil activities, and how much is due to a slowdown in investment. And, Speaker 3, you noted the amount of unavailable gas fired CCGTs in December, January, 2017, 2018, and I'm wondering why the pay for performance reforms aren't addressing that, or, if they are, is that still an issue, and if they're not, is the pay for performance penalty just too low?

Moderator: Let's have Speaker 1 address your question to him, because the FERC folks need to leave, since it's pending, and then let's take a break, and have the answer at the start after the break.

Speaker 1: For background for everybody, we have an EnAS offset that we use when we calculate the net cost of new entry in the capacity market. And the intention is that has some level of reflection of the expected energy revenues, so that when we calculate the capacity prices, they're not gross prices, they're net prices, net of expected energy revenues. We did not file a proposal to augment that with the scarcity pricing proposal that we filed, for a couple different reasons. One is, the way it's designed now, it's intended to be a three-year historic look, with a catch-up period. So, it's always intended that there be a three-year lag. So, if we make energy market changes, there was never intention to augment it, just because we changed the energy market, because it will catch up. That was one issue. The second issue is because, if we agree that it needs to be augmented here, when do we stop augmenting it? Because we continually change the energy market. And so, we are not going to propose to change that, although when we file reply comments, we may say, "FERC, if you feel compelled that this needs to be here, here are some guidelines on how we would think you would do it in a rational fashion." And so, that's kind of where we ended up on that.

Speaker 2: OK. I'm going to paraphrase the question. The questioner was asking how much of the decline of the reserve margin has to do with the increase in load, versus not enough new generation coming in. I would say, yes, there has been an increase in load, and there has been quite a large percentage increase in the fracking load out in West Texas. But that percentage is based on the West area load, which traditionally has not been that high. So, primarily, I would say that the decline in reserve margin is just because the normal generation resources are not making enough revenue. And that's the cause of the declining planning reserve margin, because we do discount the new wind and the renewable resources that come in, based on the capacity factors, so it's not that much of an increase.

Speaker 3: So, there are two versions of the question for me. One version was, does the pay for performance design that was approved by the Commission in 2014 in New England help with all of these problems? The not-as-polite version of it was, "Why doesn't PFP take care of everything, and why do you have to do anything else?" At least, that's how I interpreted it. It's my paraphrasing. I think the answer to the first question is, yes, it does help substantially, both in theory and in practice. In theory, we have increased the marginal incentives during tight conditions, basically, to $9,000 from what they were before, which was topping out at about $3,000. That's real money. You get 20 hours of that, that's the difference. That will pay for your annual carrying cost for your dual-fuel capability of many, many tens of millions of dollars. That will get paid in 10 hours, 15 hours, right off the bat. And what we have seen, leading up to this year when pay for performance took effect, is substantial, though mostly things that we cannot document, because they're commercially sensitive. Changes in gas contracting practices. Additional upgrades to dual fuel, and a lot of routine plant-level maintenance to make the likelihood that you go to start and you cannot start dramatically smaller today. All of which is just real CapX in one form or the other.

However, one can make the case, and we do it in detail in the paper, if you're real interested in the detailed argument, that that doesn't fully solve all the problems. A useful way to think about it is that a lot of things you need to deal with, especially the fuel security issues that we face, involve a CapX, or fixed costs that don't really increase the capacity of a unit at all and won't be remunerated directly in the capacity market. They would be remunerated in higher revenues during shortage conditions, because the marginal incentives and the compensation is higher. But marginal prices don't always provide the right incentives for resources to incur fixed costs. It is, in some sense, one of the fundamental problems in economics. One of the ways that those problems are often solved in real markets, however, is with options, when someone can provide a valuable service, but they have to incur a fixed cost, and it's highly uncertain where that service will actually be needed in real time or not. Often, the privately optimal decision is, if you're just facing spot prices, don't incur the fixed cost, because it's too likely it will never be needed, and you'll get the high marginal price in return. But if you write a contract as an option, the seller will tell the price, make the fixed cost at a level which they're willing to do so, given they get to keep the option premium. And then they'll deliver it or not, based on the marginal incentives. And one of our key insights was that many of the things that we think need to happen in our markets are not happening because that contract structure doesn't exist. It's very familiar, if you ever worked in real option theory; it's only new to the power markets. Other industries have been doing this for decades. And this is a device that will help to address the shortcomings of the existing market design that really come to the fore in New England, perhaps more than other regions. And so, that's a much more sort of nuanced and complete economic answer, and I'll refer you to the paper I cited earlier, if you would like the 70-page version with all the numerical examples.

General Discussion.

Question 1: Thank you to the panel. I would recommend reading the paper that Speaker 3 just mentioned. It's got a lot in it.

So, I have a comment which I'm going to pose as a question. It connects to something that's happened in ERCOT. They have another problem in ERCOT, which is the way they collect for transmission investments, and it's done on critical peak periods, and you don't know what they are before the fact. It's only after the fact. This is actually a problem, because it turns out they're not transmission constrained during these periods, but that's when they're collecting the money. And it's produced a small consulting industry in Texas of people who advise people that, "We think this is going to be a critical peak period. You should reduce your load, so you don't have very much load during this critical peak period, because then you can avoid paying the transmission costs." Of course, it shifts to somebody else, and all that kind of thing. But what it does demonstrate is that real-time pricing can work. And people do respond to it in a big way. And that gets back to your chart, Speaker 3, about this choice between fixing real time pricing or, number two, doing a better job with the operating reserve demand curve. And I'm asking you, essentially, isn't that a false dichotomy? I would say, do both. And I say there's no conflict between the two of them. They reinforce each other. And it's a mistake to think of this as an either/or, and so, is that right? [LAUGHTER]

Respondent 1: So, I actually completely agree. I certainly did not intend, by any means to imply that we should think of those as competing alternatives. That is the wrong way to do it. My point was that it is quite possible that the least-cost way to do all of this would just to have a little bit of the market face at the margin real-time pricing incentives. But that does not mean we should also not have proper scarcity pricing for all the reserve products we actually need to run the system efficiently. Those should both be done. I guess part of what I was really aiming at, though, was to try to engender, in this audience and in the broader policy arena, a focus on the goals of scarcity pricing, because I think sometimes that is too opaque, or it's taken as, "Well, you do this because of a reliability rule says you have to," which is the wrong answer, in the sense that it is not nearly, or should not be, a complete answer, if the reliability standard was based with no considerations of economics. And that was much more my focus. Though, again, I fully agree with your comment.

Question 2: I was struck by this slide about Europe's power markets and the closest analogy to their structure being pre-2001 in California. Having used Bill and some of his colleagues in the California refund case, which is now dead, I learned a lot about how that market structure came to exist in the United States. Can someone shed light on how it came to exist in Europe?

Respondent 1: The short answer is, what Speaker 4 was referring to is the zonal pricing, and that actually arose in the UK, back in about 1989, or 1990, when they were doing their first round of reforms. And it was just a political decision that was made by the government that they were going to have a single price for all of the UK. And then that mindset, though, was carried forward. I wasn't as much involved in that conversation as I should have been, but the mindset carried forward was that the big challenge here was to make everything easy for traders. So, we wanted to have a lot of trading, a lot of liquidity in trading. That was going to solve the problem, and so that led to things like a single price for the whole region, and the power exchange, and balanced schedules, so that people had to be balanced. So, that means big traders could do better than small traders. And a very active participant in that conversation was a company which was deeply involved in the natural gas market, which was then coming into the UK, and it is in fact a four-letter word. Which is Enron. And so, Enron was influential. I don't think they were the only ones making these arguments in Europe, but they were certainly influential in both arenas.

Respondent 2: I'll add to that an interesting institutional feature about Europe, which relates to sharing information and taking orders about operating national infrastructure from some computer that's sitting in Brussels. So, my understanding is that European TSOs do not feel comfortable with running a coordinated optimization of the full European grid with their detailed network information in that model, because some of this information has to do with national infrastructure, and also (and the reason I'm saying this one is because it was voiced very explicitly in a workshop on nodal pricing that we had a few weeks back in Brussels at the Council for European Energy Regulators by the German regulator), according to a statement I heard at the Brussels workshop, "I don't trust my colleagues." So, my understanding is that a German TSO would not necessarily like to have orders coming in from a co-optimization that is out of German jurisdiction. So, that was, to some extent, the way I interpreted the statement.

And then there are also more sensitive country-by-country issues. So, a nodal price in southern Germany, where you have a lot of industrial loads, would imply, at least temporarily, a high price for German industry load in the south. So, that has implications for competitiveness. I was very encouraged to see that when a discussion in that workshop went to the fact that we have solutions for liquidity and FTR trading, with the concept of hubs, and then you can still use spokes to settle the fine grained details from a hub to a Europe specific location, there was a lot of interest in that. There was a lot of interest in how the Americans do market power mitigation, because that's also another concern. So, there was an honest interest in understanding better how Americans have resolved liquidity issues. But I found this presentation by the German regulator quite astonishing, on that same day. So, that's a bit of extra information regarding how the situation is in Europe right now. At least the way I see it.

Question 3: I'm struck by the similarity between Speaker 3's threshold question, which I take essentially to be, "Should the perfect be the enemy of the good?" and the discussion at yesterday morning's panel, with regard to the climate and carbon solutions, and how the other spin on that question is, "Can we allow the good to be the enemy of the perfect?" Or, "Will the good be the enemy of the perfect?" So, I'd like to tease out a little bit more what the barriers to achieving the perfect solution are.

Also, picking up on what Speaker 2 said about smart metering allowing disconnection and reconnection at the meter level, given that customers value electricity based on the uses to which they put it, we're essentially asking them, right now, to make an either/or distinction. Do they want the service at all or not? My question is, do we need to pay electricians now to install smart panels, so customers can actually value individual services that they're using electricity for, and protect certain services like medical equipment or HVAC? Do you think we need to go to that level of granularity to actually get to the real real-time price signal?

Respondent 1: This is just kind of like a dream thing. Retail electricity providers in ERCOT, on the company side, and even in the munis and co-ops, they're relying more and more on the internet of things. They'll give it text messages, and, if you have a Nest thermostat, you can control your Nest thermostat from the office. Things like that are coming up, so you don't need to have another panel installed by an electrician. You can directly control a lot of this high-energy-consuming equipment automatically or by your cell phone, if you get a text message. So, I think these things are coming. It's a question of, are the customers willing to adopt that?

I'll give you an example. I consume a fair amount of energy. But my monthly bill is nowhere close to how much I pay for my cell phone, or for the family and internet and cable. And if I talk to my daughter, she'll probably say, "I don't care about electricity. I don't care if it's on, but give me my internet." Right. So, the prices are still low. So, that's where the scarcity pricing becomes so important. How do you value that? Will it come? I will say, with the robust retail competition in ERCOT, it will come, provided the prices are there. So, I don't know if that answers your question or not. Technology will enable it. You don't have to put some additional infrastructure stuff in. So, when I'm talking about disconnecting the meter, it's when the stuff is hitting the ceiling fan, and the ERCOT has to do something. What I'm hoping will also happen is, as we get into emergency conditions, you don't have to have individual houses, but if the REPs have hedges, and if the prices are there, they know it's going to be there for some duration of time. Right now, the scarcity pricing is there enough. There's a time lag between when they sent out text messages and when they expect a response. Given that lag, if that price is sustained for a long enough time, you will see some passive price response. So, there are two aspects to this question.

Question 4: I wanted to ask everybody to talk a little bit about increasing operating reserve needs associated with increasing levels of renewables. In particular, I think people correctly pointed out that most of the need is in these longer-duration, 30-minute-plus to multi-hour-type ramp events. To what extent have you guys looked at the use of the existing contingency reserves, the non-spin reserves that you're holding for large fossil or nuclear plant outages? Have you looked at using those types of reserves for the very infrequent, a couple time a year, large, renewable forecast area events, where, basically, generation comes in a couple thousand megawatts below your expectation, in a fairly rapid forecast error event? What are the risks associated with dipping into the existing type of reserves that we're already holding, as opposed to the savings that you realize by basically using those existing reserves, as opposed to creating this whole new category of additional types of reserves that you have to hold on top of that? Have you guys looked at that? Any thoughts?

Respondent 1: Yeah, we looked at that, generally not by choice. Generally, on a day when generation falls off unexpectedly. We don't think of it as just dipping into that. We think of it as, you do every blinking thing you can do to keep the lights on and maintain the reserves, because what happens if a nuclear unit trips at the same time? It's a really expensive solution. We don't have quite enough renewables that that's a pressing problem yet. But it's potentially out there. It's driving us to think about more cost-effective ways to balance the wind.

The other piece that I'll note is the potentially game-changing nature of storage technologies. There's the potential that that could be the kind of resource that really provides a lot of these capabilities, going forward, at least if the ISOs create a level playing field for it all.

One of the nice perks about my job is that everybody who's got a brand new electrical thing that they think they can make money at the LMP at, whether it's a toaster or a modular nuclear reactor, comes to see us and tell us how it works and asks us what we think. And I usually scratch my head and say, "Good luck with that." And the batteries came in initially and said, "We're going to make tons of money selling frequency regulation," and I said, "Good luck with that." And they've all realized they're not making any money. [LAUGHTER] And a part of it is that the capability and potential of that technology is really most valuable if it can run and discharge on something like a daily cycle, or a long multi-hour cycle, because that's what our system fluctuations come at. And that's the time frame over which unexpected issues in the pipelines arise. Gas is not like electricity. It doesn't shut off in a second. It takes an hour or two to spin down its pressure and come back up.

So, I think the answer to your core question is, that can be done, and it is what we will do today. It is a costly solution to increasingly rely on that, given the changes in our system going forward. It will be much better to have a broader menu of products whose capabilities better match the stochastic patterns of the time and frequency and duration patterns of the fluctuations that we have to live with going forward. That's my high-level answer.

Respondent 2: For ERCOT, if you look at our current product, the non-spin 30-minute product, we do look at net load forecast errors in that. So, it's kind of baked in. A new reserve product should be pretty much the same, in that sense. The new reserve products are really geared towards decoupling our "responsive reserve product," which is a bundled product of governor response, as well as our 10-minute reserves. So, we're kind of splitting that out. And I think that allows us to kind of not force a particular technology into one or the other. They can choose.

Respondent 3: We have a similar differentiation in our system of secondary and tertiary reserves, which are expected to respond within seven and a half and 15 minutes. There's not necessarily a distinction between contingency reserve or not, but the computation of the requirements by the systems operator is a blend of failures and forecast errors. So, when they set their annual reserve targets, they kind of think of the combined uncertainty. But one thing I do want to mention, and the details of that are described in our report, is that the theory of scarcity pricing is complete in the sense of accounting for substitutability of fast-moving and slow-moving reserves. So, what you get out of the math is that, if there is a resource that can respond more quickly, it's collecting another component that has to do with its ability to respond very quickly if there's an immediate trip, for example. And, also, it collects some of the benefits that are anyways collected by the resource that can respond within that larger time horizon for something that's slower moving. So, the fact that you have a substitute built in your dispatch model implies that the adders are accruing, so the stuff that can move really quickly is getting actually better remunerated, and that's consistent with the fact that it can move more fast.

Respondent 4: From our perspective, the more articulated we can get with the reserve products we need, the better off we're going to be. (Within reason, right? We don't need 29-minute reserves and 30-minute reserves. We need them bracketed.) But for your example with the wind ramping, if I only need to recover that within a half hour, why am I going to buy more 10-minute reserves? It's just going to cost me more. And so, in the interest of minimizing the cost to the load for the products that we need, we tend to do a better job of doing that when we can get as articulated as we can around the requirements and around the product and things like that. So, that's why you see us looking at 30-minute reserves. We also are thinking about something along the lines of load balancing, which Speaker 3 talked about, because, in the load balancing context, there are a lot more resources that can provide reserves within 90 minutes to four hours than can provide reserves in 10 minutes. And so, there are a lot more options. You can typically get it a lot less expensively, but still meet the reliability criteria you need to meet.

Question 5: Speaker 3, you indicated that what you thought you needed was a small percentage of load that would actually see a real-time price. I want to ask you whether or not it's possible to get something equivalent to that, based upon what happens with settlements in the ISO. So, ISOs today settle on a zonal and hourly basis, but one could imagine a settlement system where, for those customers that had interval meters, you settled those customers separately on a nodal and interval basis, based upon their actual meter demand. Now that wouldn't necessarily affect the retail price that they would see, but it would certainly affect the incentives given to the retail suppliers serving those customers, who would then either have an incentive to pass through those price differences, or to work with those customers to mitigate their demand when prices were high, so that they would gain the benefit of the difference between the real-time price and the hedge price.

Respondent 1: Just to clarify a little bit. We do settle on five minutes today. From the load side, in most parts of New England, we settle load on a zonal area basis, dating back to a compromise (that I cannot defend on economic grounds) going back 20 years, but with New England it has turned out not to be a big deal, because we have very little transmission congestion. At least, within the state of Connecticut, it's very rare that we have constraints bind, courtesy of spending more than a billion dollars a year on new transmission for 20 years straight. [LAUGHTER] So, I don't know that what we do today is very far off what you're suggesting, in terms of the incentives that we can provide, with the exception that the prices we're sending are at the point of interconnection, because that's where an ISO sets price. And there are multiple layers that go between that point of interconnection and the household or the consumer, except for a handful of industrials who are so big that they buy it at the transmission voltages.

I'm just going to admit that I don't fully know the answer to your question. Why it is that case that the retail sector that's competitive in New England, which is mostly commercial industrial, not much residential, does not internalize the value and the lower cost that they could offer a customer if they had the capability, or they knew they could price in the benefits such that the customer itself would reduce their load during the highest-priced times? Why we don't see more of that is a question, because we do monitor the short-term load forecast, and if this was happening, we would see the price response in our data. And we don't see very much of it today. So, I guess I would maybe put that back as something that I would be interested in hearing other thoughts about, from people who know a little bit more about the retail contracting structure than I do. I don't quite know why.

Questioner: I don't know in New England. I can tell you that, although it's changing, historically, in Ohio, once it got to the zonal or the utility level, it was allocated among retail suppliers based on the historical load curves, rather than based upon the actual demands of their customers. Now, that's starting to change. But that is arguably a wholesale settlement question. So, you could specify that, where there are interval meters for customers, their settlement must be based upon the interval meter demands of those customers. And that would, could effectively create the incentive, I would think.

Respondent 2: ERCOT pretty much settles in the competitive areas. Even for the residential meter, ERCOT gets the residential meter data. But the PUC has a rule that all loads shall be settled zonally. I think that's a political decision. So, if anything needs to change, you'd like to make a nodal settlement, but I think even the REPs will oppose that. Maybe the rate would depend on which side of the street you're on. And it's very difficult for the REPs to set rates for that, so.

Respondent 3: Along the line of what Respondent 2 just said, I would think that something like that would have to be mandated, probably, rather than being voluntary, because what you could end up with is all the people on the sending end of the constraint with low prices getting interval meters, and all the people on the receiving end not getting them, and paying the average price. So, then you've got this sort of tangled-up mess. So, it seems like that would have to be something that would be done uniformly, or else you're going to get some strange behavior around who has meters and who doesn't, those kinds of things.

Questioner: Well, you would separate out the people who have the interval meters, and everybody else would just settle based upon their load curves, presumably. And that would ultimately give you an incentive for more people to want to have interval meters, so that they could escape those high residual price areas. If you have a low price, getting a meter is in your best interest. But if you're on the wrong side of that, you want nothing to do with a meter, because it can only harm you. If you're paying an average price now, versus a locational one with a meter, that's higher, you're going to lose, no matter what.

Respondent 3: Well, but you would take out the lower price people in the average for the residuals, so…

Questioner: Then you'd have to re-compute the aggregate price. Even then --

Respondent 1: This is putting the death spiral to your advantage. This is what you're after, right? [LAUGHTER]

Comment: Going back to an earlier point, even though we have zonal settling in our costs, it's empirically the case that the 4CP, in a sense, incentivizes load response. So, there's no doubt that it works. Right? It's just a matter of whether it is locationally appropriate at this point. Empirically, that already works.

Question 6: What I'm hearing in New England now is that we don't need to build a pipeline, because we're building all this offshore wind, and that will obviate the need to build the pipeline, and, besides, building the pipeline is inconsistent with what we were talking about yesterday morning, which was that we want to decarbonize as quickly as we can. Do you think that the offshore wind in New England obviates the need for a gas pipeline? Can we do with one and not the other?

Respondent 1: That's an excellent question, and I think one that will get a lot of attention in our region. I think a thoughtful analysis of it has to really break it up into two different pieces. One piece is sort of annual energy. Offshore wind, based on the profiles that we get from the developers who successfully have brought very large projects to the North Sea, performs much better than terrestrial wind, at least in New England, by our projections. It has much higher capacity factors, and it's less volatile. There's certainly the potential, given how much potential offshore wind development there is, that it could substantially lessen the concerns that arise when there's not enough gas. There's another piece to this, though, which is what we call the "bad day" problem. I was at a conference yesterday in Washington when a knowledgeable speaker pointed out that various states, running from Maryland up through Massachusetts, have announced firm plans to bring a total of 21 gigawatts of offshore wind to the currently leased areas. The numbers are just off the charts. Now, that counts New York at a full 9,000 MW. Not all of that's leased in New York (and it will be an interesting squeeze into Montauk). But I think there will still be the issue that, as best we can forecast it, wind exhibits sometimes very large unexpected variance, as you saw in that purple curve, and a gas pipeline does not, unless it's constrained, and that will require us to continue to try to develop the kinds of things we're doing to try to address it.

To the core of your question, I will really have to say, "Time will tell." Because I think there are still too many uncertainties about how much offshore wind is coming, and what its performance will look like, in particular during cold weather. And as we begin to get more information, I think the region as a whole will be able to become much more comfortable understanding that implicit tradeoff that we seem to be making today.

Question 7: I also wanted to connect us back to yesterday morning. So, I agree, I think we're in the right place, focusing on industry market reforms, and evolution of ancillary services for the near term, with increasing renewable build out. But I wanted to ask, if you come at it from the other direction, and jump ahead to the mid-2030's, maybe 2040, and if you believe the charts that we saw yesterday about where we will be in terms of the generation stack, what type of market structures will we need for ensuring that there's enough revenue for resources to come on and for the existing resources to sustain themselves? Because I kind of scratch my head on the question, will there be enough money in an energy market which doesn't produce much in revenues when you've got to a deeply de-carbonized state? You know, with low or zero marginal cost resources in the energy market. Yes, you've got a vibrant ancillary services market, which provides some form of revenue, but is that enough to bring on a gas unit? Because you'll still need some gas for balancing, but, if you believe the charts of where we're going with decarbonization, what does that look like, and then, how do we have what that looks like in mind as we're making changes today? Because ORDC changes and ancillary services changes, they take several years to even kind of develop, much less implement. And so, if we're aiming for a 2035 world, that's kind of around the corner. And so, how do we make the decisions today, in terms of market reforms, that set us up for where we need to be with that next step, so that we're in time?

Respondent 1: I don't think we're too far off from where we need to be. I think the reserve market review that a lot of us are going through right now is a great place to start. Do we have what we need? A lot of the products we have today are based on the loss of centralized generation in large quantities in one blip. And that may not be the issue we have, going forward. So, I think a review of those reserve products is a good idea. I think the ORDC changes are valuable. I'm probably a little less optimistic about the renewable trajectory. I struggle to see a place where we don't need dispatchable generation that runs on some kind of fossil fuel, even if it's in small quantities. And if you think about the design we have now, the unit that's on the margin sets the price for everybody. So, there could be 99 percent of the supply provided by zero marginal cost wind, but if the guy that's on the margin that's controlling the balance is a gas unit, and it costs us 30 bucks, everybody gets paid 30 bucks. And so, I don't know that the principles that underlie that model fall apart in the zero marginal cost space. I think, definitely, reserves get much more valuable, because there's going to be a need for a lot more balancing services for uncertainty and things like that. But I don't know that we're too far from where we need to be.

Respondent 2: I'm kind of echoing Respondent 2's point of view. The other thing I would like to say is that if storage comes in, that could provide some amount of balancing service. Australia is probably going to face a situation in the next couple of years where they claim that there will be some periods of the day where there is no transmission connected supply side power, it's all DERs. So, I'll be watching them.

Respondent 3: To the questioner, your preface was sort of 2030, 2040. And once you're going out that far (by which time I hope to be looking back on all the things I did from the beach) I'm not as confident as Respondent 1 indicated he is about the products and services that far out. By then, we could all be driving electric cars and there could be a whole new world.

What I do think is likely to happen is, there are a couple things a few people have highlighted that are sometimes underappreciated. One is, there will be dramatically more volatile prices, real-time and day-ahead. Bill Hogan has a picture, in a couple conferences he's done, where he updates something that I remember learning 20 years ago, about missing money. Remember that? But he just superimposes on what economists call a backwards bending L6 supply curve, which is a supply curve in the short run, for a real-time market. Its dead flat at zero, until you hit the short-run capacity constraint. Now, it won't really be a vertical capacity constraint, from a pricing standpoint, because we'll have Operating Reserve Demand Curves that you'll escalate as you get there. But it means you get bang-bang pricing. And we're already seeing that in New England. If you'll look at our real-time charts, you can see that on some days we're going around zero, zero, zero, zero the last 20 zeros, and then, bang, 150 bucks. And it's happening today. But if we go forward, we're going to see a lot more of that.

The broader question you're teeing up is about financing investment and what capital structures give the kind of efficient capabilities, including with the balancing services. And I think what this means is that the markets will have to move, the entire industry will have to move, to a world where there is dramatically more volatility in the energy market prices. That scares a lot of generators seeking financing, but there is a good answer to this in economics, generally, which is, "You hedge." And the role of hedges will become far more important in the future than in the past.

One question that I don't know the answer to, because it is as much political as it is economic, is whether the ISOs will be asked to be the ones to transform existing capacity market designs, which focus on installed megawatts, to something that's instead focused on long dated contracts for energy, which is the scarce thing in the future, not capacity, which means having the ISO administer a hedging market, or, if it really can be fully addressed through capital markets on their own. Certainly, ERCOT has experience, as new combined cycles get brought on there. They certainly have been able to attract financing to finance those new plants, in the face of extraordinary potential volatility in revenue streams in ERCOT's energy-only market. And I have a lot of reason to expect that kind of a market could work very well, long-term. But it is riskier than today. It requires a lot more hedges, which means, ultimately, that consumers may pay more, because those hedges are not free, and in some sense that is the additional cost of managing a much more renewable intensive system that's inherently more volatile, and it may show up in the capital markets in that fashion. So, that's my best effort at a rather opaque crystal ball.

Respondent 4: One concern that I've heard come up repeatedly is that what feels very different in this new world is multiple days or weeks of bad weather, and how you ride through those. So, there is this policy model used by the European Commission for setting roadmap goals called Primes. So, in some of the discussions I've had with the developers of Primes, their view is that the big solution out of this would be the coupling of the electricity and heat sectors. So, in my opinion, what we're discussing here today is a no-regret measure. So, what you're describing with the future supply functions that look quite flat, it makes a lot of sense to put this in place, and it's something that is needed. My concern, and what I'm asking myself is, is that enough? So, how do you send the proper price signal to put together an infrastructure that can store multiple days or weeks of energy, if that's needed, in order to ride through the tough weather events? So, obviously, scarcity pricing, and all this is not contradicting that, but the question is, do you need more?

Question 8: So, the question just now described "bang-bang" pricing, and I 100 percent agree with you. I've often wondered about some of the underlying derivations of the ORDC, some of the parameters, but one of the observations I've had, and I think Bill's made this observation, is that maybe these parameters don't matter so much, but by spreading out the trajectory from low to high prices, it really helps passive demand response. Passive demand response and "bam bam" pricing are really hard to make work together, right? The price is low, nothing's gone wrong and then suddenly it's high, but it's too late, right? Whereas, if that's spread out, you get that ability for the passive response, and so then I might argue with Bill about exactly how to derive the ORDC, but maybe it doesn't matter, because that becomes subordinate to the effect of the passive demand response and bringing a lot more elasticity. So, I just wanted to comment on that, and I think that's particularly relevant for ERCOT, where there is potentially a lot of latent passive demand response.

Respondent 1: I would agree with that at a conceptual level. The point I would offer to the audience is, I think we're getting close to doing something that moves in that direction already today, through what's generally known as multi-interval dispatch and ramp pricing. There are some initial forays that were done in California, in CAISO. I think perhaps, as we have done more rigorous work on this since, the next generation of market designs dealing with ramp pricing will have a much more sophisticated way of doing exactly what you are suggesting. We have been working on that. We are mostly intimidated by the software development costs, and the fact that the broader industry does not yet seem to have viewed that as the same priority that your comment suggests.

Question 9: So, Speaker 3, with the design changes, there are two questions. One is, are you going to be able to sort of project what you think's going to happen, given you're talking about options that I think are typically difficult to estimate the prices of, and sort of having market power control mechanisms in place? And then, second, we're sort of saying we don't know what the response will be. I mean, is it still maybe that it will be enough to have dual fuel? Is that sort of thrown out, at this point? I've always thought that state regulators, environmental regulators, if push comes to shove and it's down to keeping the lights on, they're going to permit some dual fuel. And I'm just kind of curious of the big picture, and where that will end up, in your opinion.

Respondent 1: On the first issue, no, I don't think people who do this for a living will have any difficulty doing this. One of the things that's been interesting is that the people who come in to see me outside this stakeholder process are not the vice president of regulatory affairs. They are bringing the three people from the commercial pricing unit who have MBAs from Wharton and from Texas, who come down and show me their market distribution models for the pricing, and we talk about it. And they're like, "I can do this," and off they go. I mean, like I said, this is new to this industry. It is not new to the commercial world of financing things.

On the broader question you asked, I expect that, over time, there is likely to be considerable interest in doing things like dual fuel. That is a little harder to model out than something like contracting for LNG, because it bumps up against a very changing landscape on air permitting rules. For example, resources have been putting in dual fuel when they go into Connecticut, but they're getting much more restrictive rules in their air permits on how much they can run and when they can run. They have been doing less of that in Massachusetts. The response we get is that it's a reaction to what the states will allow them to do. I don't really feel knowledgeable enough to predict exactly how that will play out, but I think the economic incentives will be very strong for that to happen.

Question 10: I would be sorely remiss if I did not respond to the pipeline question that you asked. I think (and I lived it painfully for four years when I was with the Mass Commission) that if you had a candid conversation with the administrations of the six states, I mean a candid one, I don't think any of them would tell you that you don't need some gas infrastructure. I'll go to my actual question. I just had to say that, because I lived it.

There's been a back and forth about real time pricing, and in the restructuring legislation in Massachusetts, there was a little piece in there about municipal aggregation, and it's been fairly sleepy. But in the four years I was on the Commission, we are now almost at 80 percent of the residential customers in Massachusetts who are under municipal aggregation. So, I go to your question about real-time pricing. Who's going to do that? Because, again, the Commission and the state can control the utilities, but how are suppliers going to offer that? I only put that out there because I don't think a lot of people are paying attention to it, because it's happened very quietly. I believe Boston is about to go muni-ag. The other largest city would be Worcester, so it's just something that you really need to think about.

To something else that was said earlier, and I'll say it very quickly, when I was with Associated Industries of Massachusetts and, in the early 2000s, we were trying to get businesses in Massachusetts to do demand response, telling them, "You can make money," they weren't interested. And it's different than Ohio. I mean, Fidelity doesn't care, or any of the financial institutions. Obviously, the hospitals don't. So New England is different than Ohio in that sense. I'm not saying it's right, wrong, or indifferent, I'm just telling you that they don't care about the money. So, it's just different. But thank you. Great panel, great job. [LAUGHTER]

Question 11: My question is about geographic or topological variation in the ancillary service prices. We spend a lot of time with nodal pricing, getting the prices right at the nodal level. And if we believe the long run future and the bang-bang prices, more of the margins earned by resources in the market are going to come from our ancillary services, unless it's from the pure energy prices. Or, I pose that as a hypothesis. Maybe people would differ. And so, I'm wondering what the New England, Texas, and PJM market designs are thinking about, in terms of zonal or some kind of geographic variation in prices. Because I understand that doing that on top of the nodal pricing for energy is hard, just computationally, particularly in real time. And so, I'm wondering, is that going to be a future challenge, to make this all work?

Respondent 1: When we started our design discussion, we started to go down the road of nodal reserve pricing, and we had a couple conversations with Bill, and we were like, "Oh, that looks really hard, and we're not going to be able to get it done in the timeframe in which we need to make reforms, and so we're going to sort of set that aside and we're going to move forward with the regional model that we have." I think New England's got one, as well. I do think it's a nut that we have to crack for some of the reasons that Speaker 3 said earlier, which is, you've got resources within a region with a nonzero reserve price that can't deploy their reserves, because they're bottlenecked. And so, from a load perspective, you're paying for something that you're not getting value out of. And we need to fix that problem. I think, just for us, there were bigger issues to tackle first. I do think that's something that needs to get resolved at some point, but we need to figure out how to do that at a time frame that we can run within the five-minute dispatch, and, frankly we're just not there yet.

Respondent 2: A similar response. MISO has published a couple of papers on some sort of nodal reserves. When I talked to them they said that they had discussions with their stakeholders, and it didn't pass over there. But we are following it closely on the nodal reserve part. In terms of zonal reserves, one of the challenges in ERCOT, is we build transmission like crazy. So, how do you define these regions? There are constraints that could disappear in a matter of one year or two years. So, we are kind of in a waiting game. On the nodal reserve, we are kind of taking a wait and see approach. Right now, we are thinking the only product that we may look at is the non-spin--the 30-minute product. But we'll have to see how we are going to define those regions, if there's a requirement for that.

Respondent 3: I'd just say briefly I essentially completely agree with the other respondents here. We have a very sophisticated system of zonal real-time reserve pricing, circa 2006. And the world has changed very dramatically, but pushing beyond that is technically challenging, though it is where we need to go.

Question 12: One of the exciting things we see here is that we could get a lot more ancillary services from the demand side, which is especially important in a high-renewables world. But the DR industry, at least in the East, will tell you that scarcity pricing events are just too few and far between to support a business model. And then everyone in turn points to the high reserve margins from capacity markets as basically burying the price signals. So, the question I get to is, can these models peacefully coexist with capacity markets, or are they part of some path to wean ourselves off of them?

Respondent 1: I think they can coexist. There needs to be an interaction between the two, obviously. I talked a little bit about the EnAS offset that needs to exist, and it needs to be, probably, more accurate than it is today. We need to get better at that. I think, eventually, the better we do scarcity pricing in real time, presuming a reasonable reserve margin, the less we'll need to lean on the capacity market for revenue sufficiency. So, to some extent, it is sort of an off-ramp from the capacity market. I think the bigger issue for us is, we operate to the one-in-10 standard, and we don't need the capacity that warrants that every single year, and that capacity's got to stay around, one way or another. And I think, until you do what ERCOT does, where you say, "We're not going to stick with that. We're going to move to a market-based reserve margin," I think it's hard to get away from a capacity market. However, the better we do with real-time pricing and things like that, the less reliant we become on that. So, yes, they can coexist. I think scarcity pricing and reserve pricing is a way to get less reliance on the capacity market.

Respondent 2: I think the ERCOT answer is, "We don't have a capacity market." [LAUGHTER] We have a very robust response from the load resources, or demand response in the AS markets.

Respondent 3: I think the short answer is, they can coexist, though awkwardly at times, and sometimes uneasily. They may well be the path out of sort of the traditional resource adequacy capacity market design, over time, in the same sense that ERCOT has sought to do. I think a question that is very interesting is, how will the balance of revenues between the energy and the capacity markets evolve? If those ultimately go to a system where energy is scarce and capacity is not, the market itself will shift the revenues. I don't have a good enough crystal ball to know whether or how quickly that might happen, though. But it's an interesting question.

Respondent 4: I think they're perfectly consistent. Now, on a practical level, there's a question of long-term risk, as well, so, if you talk with Engie, they will tell you that their interested in combined cycle gas turbines in Europe does not exist anymore, given the unbalance of where European electricity regulations might go in a few years from now. So, it's also obviously in their interest, but they developed the argument that scarcity pricing would not cut it for them, and they would like to see capacity markets in place. But the Belgian regulators' position on this is that we need a proper real-time market if we're going to deal adequately with renewable integration in the future. So, there's nothing to lose by designing properly the real-time market, and then, you know, all options are then on the table.