HARVARD ELECTRICITY POLICY GROUP

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Rapporteur's Summary*

Who is Buying: Renewable Penetration, Market Risks and Long-term Contracts

FERC policy statements have emphasized that "[i]t is important that wholesale sellers and buyers have adequate opportunities to sell and buy electric power through long-term power contracts to allow them to manage their exposure to uncertain future spot market prices." If markets are intended to allow for increasing penetration of renewables, with low or zero variable costs but high upfront capital costs, spot prices that would be supportive on average would be highly volatile. Long-term contracts, to hedge buyers and sellers, would seem to be of growing importance. Mandates for long-term contracts just substitute one regulatory model for another. Competitive markets promised a different way. Do the rules for open access and market design provide the opportunity and incentives for long-term contracts? Large customers can represent themselves. But who will act on behalf of the individually small residential customers that make up such a large part of the load? Is there a level playing field for their retail suppliers? Is there an inherent conflict with default services that preclude incentives for long-term contacts? Can financial participants fill in any intermediation gap?

Introductory remarks and introduction of the panel are missing from the recording.

Speaker 1.
—and the other 13 states and these various features here can lead to some bias between them, basically allow customers to just always go back to the default service. There can be by initial placement, when you move in or out of an apartment or a house, you can have bias of where you get started.

So these items on the left side are the same features that we think have an influence on whether the retailers do turn around and operate effectively as active wholesale buyers. This is not, by the way, an overall grade about retail competition. There are other aspects of retail competition that regulators need to worry about, certainly truth in advertising and various good business practices. We're focused here just on their ability to get to turn it into long-term contracting. So you can see the grades here. They're quite low across the board for a New Jersey, Maryland and Pennsylvania, quite high for Texas. I'm sure we can argue about different, individual aspects of it but since this is the general theme, it really is very different in some areas than others.

On creditworthiness, for example, you need much greater credit to become a retailer, you hold your subject to a much higher standard than in these other states. So I will move on and start wrapping up here Why is long-term contracting important? As the Moderator said, that has been a theme of restructuring. I'm not saying it is strictly necessary, one can point to pure merchant gas generation and PJM and or point to, on the retail side, the company Go Griddy in Texas allows people to just directly get them the wholesale real-time price. My former boss Pat Wood is a big fan of that. But I don't think that most people, unless they're real energy nerds, necessarily want that. I think most people want to have some hedging either on their behalf overseen by a regulator or by a company that commits to deliver them some more stable rates. And, of course, the cost of capital can be lower and more efficient, if there is some either physical or financial contracting on the last HEPG call last week, where Larry Makovich said that he had done some work and found roughly an optimal seven-year term of such contracts. I don't know if it's seven or something else. That sounds right, anecdotally, from what I hear about contracts and in some of these markets.

But there probably is some optimal sharing in term. And I don't think it's zero. Frank Wallach has also written about how contracts reduce generation market power. And that's another another benefit. As the Moderator said up front, the contracts are a means not an end in themselves, they do provide those other values. Now, as the Moderator also said, this is not a paper wherr, I don't think today's discussion is really about renewables, *per se*, though there are some ways in which contracts are particularly helpful for renewable energy.

Number one is, of course, renewable projects are very capital intensive because there's no production costs or fuel costs, all the costs are capital, pretty much. Number two, I think as a lot of people think about market design and the long-term future, they scratch their head about, "Wait a minute, who's going to invest when prices start getting depressed from zero production cost resources?" I'm one of those who thinks that really the answer to that is pre-arranged contracts that provide that upfront revenue certainty to lenders. And that can be handled in many markets just fine. But you do again need to make sure that there's a counterparty on the other side who's creditworthy and has the ability and incentive to sign the contracts.

And then the third point is, again, it's not just about renewables. I think all resources have of anybody building anything. We probably have some EPSA folks on the call, but I would think they would also like to have credit where the buyers and the other side and that helps with their investment. So then, just a couple quick notes here and on the next slide, we'll be hearing from Speaker 3 in a bit, but the bottom point there and NRG sign 1.3 gigawatts of solar PPA is in 2019 with an average term of 10 years.

Again, I was in Texas showing up contracts do work, they are in play in Texas, and it's not something that gets discussed in the ERCOT stakeholder committees. It's not something ERCOT even pays any attention to. Why? Because it's not really any other business, you know, economic hedging is not the grid operator's job, but it does happen elsewhere in the market.

And then this quote here. You can read thisis a direct quote from an investor prospectus for a wind farm, talking about their 12-year contract which was critical to the financing of that plant. And then the next slide, from a consumer perspective. I think industrial customers are well aware of the benefits of long-term contracting and, well, you can read the quote for yourself, and then I'll just close with two slides about how this fits with the wholesale market on the next one. We can see Bill's standard slide on the overall market design. You do need the prices right. And you do need financial transmission rights to make it all work.

We wrote a report on the left side, that link there was another report that we did, that Grid Strategies did for the Wind Solar Alliance about what wholesale market design features are needed for a high renewable penetration future and what popped up there are some points we've talked about here, you do need the scarcity pricing.

One thing that does is make sure that there is no free riding in real time. So it makes sure everybody shows up to the market with enough power to serve their customers, again, like they do in Texas. That is effectively the financial penalty for not procuring in advance and then the bottom point about enabling bilateral contracts, partly because customers, utilities and others are increasingly demanding renewable energy and they want to buy what they want to buy without the grid operator second-guessing them.

Just a reminder that the Texas market can work on the wholesale side. We saw in 2019 and we talked about this in a previous HEPG meeting, but the cumulative net revenues in a year when reserved margins were pretty tight in Texas, you do get to a point where net revenues exceed the target net revenue to attract and retain needed investment. And so, again, that is a key part of not only making the wholesale market work but making the whole thing work. So we hope these retail market reforms we suggest here are considered and discussed for their own benefit in each state. But also we think it helps make the whole retail wholesale market system fit together better. I'll turn it back to you.

Moderator: Thank you, excellent. Now we'll turn to Speaker 2 and the view from New Jersey.

Speaker 2.
Hi, so this is my first time. I'm happy to speak and just kind of start giving a brief introduction as you get it started because my oftentimes with my slides, they're more informational and then I'm going to be giving a presentation. And so this is my first time ever being in an HEPG kind of presentation and I'm very excited to be here, so thank you for having me.

Just a little bit about my background. I am an attorney, I've been working on regulatory matters here in New Jersey for just over a decade and my primary responsibility is the wholesale market and kind of transmission matters and PJM and FERC. And I do oftentimes interact with our energy division staff that work on our retail market structure. And while I appreciate that the crux of this panel is about long-term contracting, what I will say is that, for New Jersey, it is going to be about those renewables and that's really what our focus is going to be on, and how do we get to that clean energy mandate that we have.

We can turn to the first slide. And so just by way of background because I appreciate that, you've already seen that that New Jersey's horribly failing, according to Speaker 1. I'll give you a little bit of background to how we got to that scorecard.

In 1995, concurrent with what was what was happening down in Washington, we were also restructuring here in New Jersey and what you'll see here, and this is why I said I don't necessarily narrate all of my slides, you'll see that there's a tremendous amount of information here and just background so that you can take it with you and have it for your own reference.

But through the mid-90s, you know, there was an Energy Master Plan proceeding here in New Jersey, which ultimately yielded a final report that discussed, among many things, the recommendation that we would transition to competition here in New Jersey, but in doing so, we would still address all of our environmental concerns, especially to the extent that those were not being addressed in the wholesale markets that we're developing.

So what ultimately came out of that was this legislation called the Electric Discount and Energy Competition Act of 1999, which in New Jersey, we call it a EDECA. I'm an attorney, so I'm going to give you all the legislative history right there on the slide. Notably, and again, because I work in the wholesale markets and everything that's gone on in PJM in the last few years, it's an important thing for us here in New Jersey to point out that when we transitioned away from our traditional regulatory structure to kind of competitive markets and we restructured here in New Jersey, we did so at the same time that we were considering different environmental factors.

And so what you'll see is that embedded in our restructuring legislation are a lot of statements about environmental quality, about providing diversity of supply of electric power here in New Jersey. Ultimately, that informed the fact that our restructuring statute also has our first renewable portfolio standard and some of our other renewable requirements. So those things have been on the books here in New Jersey for over 20 years.

Also with the transition to competition we created what was called the basic generation service product or basic generation start service. I suspect that you're all fairly familiar with standard offer service in other jurisdictions. I know that Speaker 1 did actually a pretty good job in his white paper summarizing in one of his appendices how our basic generation service works here in New Jersey. What I've provided you is our legislation. So this is the basis for what BPU does on a yearly basis.

While this legislation that I have quoted for you here on this slide discusses how we would do it, it doesn't actually give the nuts and bolts. So what BPU does in his basic generation service auction, and what we've been doing for the last, I think it's approximately 18 years, is that we conduct two simultaneous multi-round descending clock auctions and in that we procure services that meet the full electricity requirements of our retail customers that are not served by third-party suppliers. In this most recent auction that the BPU conducted in February of this year, both options secured commitments for up to $6 billion worth of purchases covering approximately 7700 megawatts of customer requirements. So it's pretty significant here in New Jersey, and I appreciate what that means is that there's not as much shopping, to the extent that this panel is also to discuss long-term contracting I do think it was worthwhile to note that there is provision in our basic generation service statute that does reference the potential for bilateral contracting, but that's limited currently to bilateral contracting with the affiliates of some of our now restructured electric public utilities.

This continues the discussion about basic generation service. And so again, I'm not going to read it to you at length, but I did want to highlight the fact that coming out of this case that I provided at the bottom of the slide, there is a discussion about the fact that changes to our basic generation service auction have been challenged and went all the way to the Supreme Court of New Jersey, where we tried to make changes to increase the amount of renewables. This was back in 2007, it took a number of years to get to the Supreme Court of New Jersey, and, in doing so, we violated certain Administrative Procedure Act requirements.

So there are very strict requirements around how we can tinker with our basic generation service auction and the board has been admonished when it has not necessarily strictly adhered to those requirements in the past. So in 2001 the BGS auction was a new concept. We considered lots of different options for how we would do it in 2002, after the process open to all interested participants aboard determined to retain this basic auction design that I explained for you.

We've pretty much continued to approve that descending clock auction format and it's proven successful here. So the process has worked well. This is actually a direct quote from the board, I believe in the 2020 auction order, where we've identified that it has resulted in the best prices possible at the time. Nevertheless, one of the things that permeates several of the boards orders on the BGS is the fact that elements of the BGS procurement process have always been and will always be subject to periodic review and potential revision by the board.

I thought that was particularly relevant to reference to this group because of the discussion about how we can kind of facilitate. I appreciate the focus wanting to be on long-term contracting, but ultimately our objective, from a policy perspective in New Jersey, is how we're going to get to that 100% clean energy.

So that is the goal of our Energy Master Plan, which was released by Governor Murphy on January 27 of this year. Recognizing that we have this 100% clean energy objective, and that that is going to be a lofty goal to meet, there's recognition in the Energy Master Plan itself that New Jersey's existing regulatory structure may not be sufficient to get us there.

I took this quote directly from the Energy Master Plan. And I think it shows our ability to be self aware that changes need to be made. And that's precisely the thing that, at least my understanding of this group, is that we're open to these kind of discussions.

For example, some of the changes that the Energy Master Plan discusses is whether or not we would incorporate a carbon neutrality requirement in our basic generation service for load or a clean energy market that would competitively source carbon-free energy. In our final Energy Master Plan, New Jersey was even a little bit more open and discussed the potential for various solutions, which you can see under this third bullet point.

And, ultimately, the Energy Master Plan leaves it to the New Jersey board to decide whether or not it will examine these pathways and the Energy Master Plan envisions that the board would kind of initiate such an investigation in early 2020 to look at how best it's going to meet its resource adequacy needs, consistent with the clean energy goals and environmental values. I again appreciate that Speaker 1 had his caveat about this not necessarily being about that, but the focus here for New Jersey is, is our existing regulatory paradigm going to work to get us to that 100% clean energy goal?

As you saw on the prior slide, our assumption is, no, it's not working. And so how are we going to get there? Just this past Friday the board did, consistent with the Energy Master Plan, initiate a new investigation into how the state would best achieve its reliability, clean energy and environmental objective, while keeping costs to consumers as low as possible. So there is a notice currently posted on the board’s website on the front page. I think it's the second item under news on the board’s homepage, asking for public comments on a variety of things, including commentary about whether or not there are contracting mechanisms or an FRR, but also discussing changes to our retail market paradigm. Are there changes to our basic generation service procurement process that we could consider that would enable us to more effectively, or even more aggressively, meet that clean energy target?

The board directed staff to conduct this process. So that is actually my division, in coordination with the energy division, which is run by my colleague, Stacy Peterson, and we will be conducting these written comments and technical conferences and public hearings. We had intended before all of this global pandemic that resulted in us not sitting together in Washington, D.C., we had intended to initiate this with a technical conference where we were going to invite expert panels to present it and really have a robust dialogue. Unfortunately, given the current circumstances, especially here in New Jersey, that's not possible at this time. So, what we are requesting is we've taken essentially the panel structures that we had intended to discuss throughout a day. And we've approached them in terms of different topics for commenters to write about.

So I welcome all of you to participate in that process. It's public, you can say all of your interesting ideas and staff is really open to them. And ultimately that comment period will close on April 29, but that does not conclude the proceeding. That's just the closure of this initial comment period. And so I think that's the end of my slides, and I guess I'll turn it back to you.

Moderator: Thank you. That was excellent, and there's a lot of material there that we can talk about later, but we'll turn to Speaker 3 and listen to his initial comments.

Speaker 3.
Good afternoon, everyone. Good morning on the West Coast. I'll just give you a brief introduction. I'm with NRG, I head up their trading function. I'm probably going to be, fair warning, coming from the competitive retail side in most of my remarks today.

For those of you that aren't familiar with NRG, we are one of the largest integrated competitive power companies in the US, we have over 23,000 megawatts of generation spread across six ISOs. We supply power to 3.7 million customers, primarily mass market residential customers, but also small, medium and large businesses and large commercial and industrial customers. We also supply natural gas to consumers in 14 states and two Canadian provinces.

So the discussion today, sort of the preamble to the discussion presume that buyers and sellers are looking for renewable products and, in so doing, they're looking to hedge their costs if you're a buyer or their the revenue streams if they're a supplier, and that this will the success will lead to an increase in demand and and so on. You have sort of a benificent cycle there.

And, in that environment, there were some questions we wanted to answer, and I'll just dive right in and we'll see how I can address most or all of these questions in my remarks.

Market designs, wholesale and retail designs, have to work hand in hand and the one relevant aspect of each that I consider important to contracting these days with wholesale markets is there a capacity market construct or not. And with retail market design, is there a utility default service or not. For analysis purposes, it's convenient that the different grids that we operate fall into only two of those categories.

So, ERCOT in Texas, does not have a capacity market, does not have utility default service supply. And the eastern ISOs that we operate in do have capacity markets and do have utility default service. The chart over on the right shows the results in 2019 of where these are getting us in terms of solar and wind in the system mixes. So this source is from ISO data for calendar 2019, except for New York I found 2018 data. So a little dated, but I think still representative. You can see that in Texas over 20% of the supply in 2019 was from wind and solar in the eastern markets that tends to be 5% or less right now.

I would not say that capacity markets are a hindrance to renewables, *per se*, but they’re a major source of revenue and to generators in these markets. And right now there's a tremendous uncertainty around state subsidies impacting that market. I'll talk a little bit more about that in a moment. But right now, if the capacity market is considered to be interfered with and there's a lot of regulatory action to come there, it's a dysfunctional market contracting, and a dysfunctional environment is generally pretty risky.

As Speaker 1 mentioned, NRG is active in the Texas space and he put up some of our stats. So thanks for that, he got on front of me there, which is great. We're really talking about a tale of two markets. So in the restructured eastern states, the utilities bill the customers and the utility default service dominates the market for energy supply. The utilities primarily engage in shorter-term procurements. If prices really get out of whack, they can use their balance sheets to defer calls and smooth things out. I will give an honorable nod to New Jersey and the BGS program there. They actually have wholesale suppliers taking that risk on.

But I would note that when the customer gets the bill is still says PSE&G or JCP&L or Atlantic City Electric. Consumers are not aware of the process. It seems that the utility’s providing the service.

In Texas, the retail energy providers bill the customers, including the T&D charges. So they have more of the month-to-month billing relationship with the customer. That's also the main information link with the customer. There is no capacity market. It's sink or swim for for all comers. When REPs default, I think this is significant, when they default presumably through their own bad management, all customer service is seamlessly maintained by other reps acting as providers of last resort.

Now we recognize that in the east utilities may have a statutory obligation to serve. But the retail market designs that the states have wound up with keep the utility squarely in the middle of things with the customer so, unlike in Texas, where ERCOT handles the billing determinants and assigns the cost to the different REPs based on what their customers do, in the east it’s the utilities reading the meters, deciding what the energy contribution was, deciding what the capacity demand was, what's the transmission demand on the system.

I know that in the east regulators, politicians and utilities themselves like to note that utilities don’t charge a markup on supply costs. So it sort of gives an imprimatur that utilities are the low-cost alternative, they handle the billing, which means that that bill control limits what competitors can put on the bill information-wise and if we do try to change a bill, it's got to be done in a large forum where everybody has to agree. The utility often needs a large cash contribution to make it happen in a fair amount of time.

So utility billing systems kind of limit innovation in competitive markets in the east, and I would contend that innovation is the primary purpose of competition, not price. Price will come along with innovation, but without the innovation first, not much can change.

I just wanted to put up a point about RPS goals. Speaker 2 had a good breakdown of what's going on in New Jersey. Some states have mandated, as you can see along the bottom, 100% renewable energy goals by

2050. These are primarily states without competitive retail markets. So here, as noted in the preamble to the session, the heavy hand of government can move things along. But we're seeing in Texas where they have a fairly low RPS objective, the customers are willing to buy and the developers are certainly willing to sell. A little more on what's driving that in a moment.

We've noticed in the east, we're not using contracting so much as we're using Renewable Energy Certificates to meet objectives and I'll talk about that in a moment as well. I just want to talk briefly about who is representing consumers in these decisions. So, in states where there is a renewable portfolio standard that's legislated, the state officials are making the determination on behalf of their constituents. In Illinois lately the utilities are directly handling that, but in the other states in the east it's all comers. It's the utilities and the competitive suppliers and we do that through registries that maintain records of renewable energy certificates, which I'll go to on the next slide.

Another method is we've seen municipal aggregation for the last 20 years now. I think it's it's going in many years under the label of Community Choice Aggregation. Local officials are signing agreements with aggregators who will meet both the state RPS objectives and they'll green up the supply even a little more. So, here, those contracts will be entered into by municipalities, on behalf of their local residents.

The aggregator will use RPS, will use voluntary renewable energy certificates and may even use some short-term PPAs, but these aggregation deals tend to be two to four years in length. It wouldn't make sense to sign a deal much beyond that, and that leaves a developer bringing a new project with a fairly long merchant tail risk. So you're probably going to get more existing generation allocated over to your aggregation group. While that does create more demand for renewables, it does so, indirectly, it doesn't get a new project built *per se*.

And where you have competitive markets operating, it's the consumers making the decisions directly for themselves. And that can be handled by voluntary RECs on top of RPS. But it can also be handled with long-term PPA. The deeper your relationship with your customer, the more stable your customer base as a competitive supplier, the more likely you are to sign a longer-term PPA that can get a new project built.

I wanted to talk about renewable energy certificates for a minute. The primary means in the east, the only means to comply with RPS, really, because you need these products that are managed through registries, where you can confirm compliance with the RPS standards. The RECs are good in one aspect, they are fairly low commitment for buyers. Their vintages are one year or half year or a month of generation. So they're fairly short-term supplies that are readily available. However, they operate in what I call managed markets, where change in law or regulation can quickly either change the supply for one of these products or the demand for one of these products or the cost of a being short the product or the alternative compliance payment, the ACP. All of these things act together to impact price.

So I've got three slides here from Evolution Markets. That's a broker in the REC space, and I asked them for a little price history and they show on the left-hand chart, the New Jersey solar REC spot price from 2008 to the present. And you can see shortly after the market started, there was an ACP payment of I think $700 a REC, a fairly tight supply so price quickly rose close to the ACP payment.

Then the market got flooded with cheap panels from overseas and the price crashed. So the developers had to go to the legislators and ask for some sort of relief and increase in demand and eventually the price is stabilized now at I think a fairly workable price.

But it's indicative of the kind of thing that can happen here. The middle slide is from Maryland solar REC price from 2014 to the present. When there was an unexpected extension in investment tax credits in 2014, you can see the price drop. Then, last year state bill 516 has passed, to increase the demand and now prices have come up.

Moderator: Can you just tell us what the units are on the vertical axis?

Speaker 3: Sure, good point. These are the price per REC, and a renewable energy certificate particularly is generated when a supplier generates one megawatt hour of a type of generation. So for the left hand chart, that would be one megawatt hour of solar generation from panels in New Jersey, we generate one REC that can then be sold in the marketplace.

Same unit for the Maryland RECs in the middle and for the Pennsylvania tier two RECs, these are hydro RECs. For instance, in the state of Pennsylvania, when one megawatt hour of hydro power has been generated from a qualifying project, then you have a renewable energy certificate that can be sold. So you see the price there. When the state of Virginia passed its Clean Energy Act and it increased demand for adjacent state hydro RECs, you can see what happened at the price there recently.

This can be a little bit of a disincentive to long-term PPAs because no buyer, seller wants wants to wind up deep out of the money on a hedge due to a change in law or regulation. So it's a little bit of an unstable environment. ERCOT is a favorable market for PPAs, and I know some of this may come up in questions, but they did develop a competitive renewable energy zones, a CREZ if you're familiar with that acronym. They built a lot of transmission to move renewable power from West Texas, where there's a lot of land and wind, to the demand centers in Dallas and Houston. They do have a regulation and quicker approval process.

But I think it's significant that competitive retailers are on equal footing with one another, which gives them a more stable customer base. And, right now in Texas, because of all this renewable generation there are actually declining forward prices that we'll look at the moment. Declining forward prices mean that when you sign a levelized contract with a developer, you're getting your benefits up front. The prices will be below contract out in the future, but you get front-loaded benefit

Typically, if you do a contract, a developer contract of long term, usually the benefits are back-end loaded, think avoided cost. For instance, you have to take the hit up front for the promise of the benefit down the road, but you have greater certainty and the backward or declining forward price.

Retailers in the east do face greater risks. So they do prefer a REC. Just note that this environment stifles long-term customer relationships and it keeps 50% of consumers with the utility, the fact that the utilities are in the default service business.

So here are these trusts. Look at the forward price of power and they have on there the forward price of natural gas, and you can see in the east markets, natural gas is still the marginal fuel. There's still some correlation, even though natural gas is generally upward sloping. Power prices are generally flat. They do have some seasonal correlation so there's still a fair amount of fossil fuel on the margin, such that you have that positive correlation.

Whereas in Texas, not only don't you have the season of correlation anymore, where natural gas prices are higher in the winter, power prices are higher in the summer. But you'll see that power prices are expected to decline over time that they're low most of the year, but they spike in the summer. That decline is due to the expected influx of renewables over time. So, it does show how this success in development with renewables can impact marketplaces, and that's fairly favorable to consumers.

We're at, I would say, a fork in road in the east, where going to return to monopolies where long-term contracts are signed by T&D utilities or states, as we're seeing in New York and others, and contract costs are charged non by passively to ratepayers. It's interesting. We even see that developers are trying to redact certain of their costs or information and these proceedings. So that's even less transparent than back in the old regulated world.

Or are we going to embrace competitive markets, where contracts are signed by competitive retailers in response to customer demand and those contract costs are born by competitive suppliers who have to build them into products that consumers want to buy, at prices that that will allow recovery?

Let me just note that because of *ex parte*, I'm going to try to speak very generally here hopefully I won't cause anybody leave the room. But we know that a number of states are not talking about FRRs or having to island their generation within the ISO and no longer participate in the competitive capacity market which has existed for 20 years and and provided fairly low-cost reliability, I would say, in that timeframe.

We've seen in Ohio, with the AIP entities that tried going their own and Duquesne in Pennsylvania left and came back to PJM. Costs are typically much higher for reliability when that happens. NRG has worked with the Brattle Group to to promote a different idea.

And I'm going to speak to that for the next couple of slides, we call it the forward clean energy market and we think this wholesale market element would allow renewables to accelerate in the east, so that we could move Texas-style penetration into the eastern markets.

About that quickly. A forward clean energy market would allow states to determine what is the maximum price that they're willing to pay for a minimum quantity of carbon-free energy. You would basically take those demands and you would also allow large commercial-industrial customers and retailers from mass market consumers to put in voluntary quantities of renewable energy that they're looking to buy and you could build a demand curve when you stack the bids from highest to lowest, which is what this lefthand chart shows. This is very similar to how capacity markets operate in the east.

Then developers could could make offers and build up a supply stack, which is what the righthand chart shows. So you've got that demand curve matched up against the supply stack, where the two curves intersect that would determine the amount of green energy that can be purchased and it would determine the clearing price that would be assigned to customers and paid to developers. We think that a market like this would allow wholesale competition and innovation to meet states' objectives while preserving a valuable wholesale market competition in the east.

The next slide shows that auction could clear, and compares that to results where states just essentially do sole source purchasing for very specific technologies from very specific developers. We feel that you'll get lower prices and/or greater quantities of green energy through a competitive market, just as we had seen with capacity markets in the east, then we'll see what direct contract. And so I encourage people to think about that.

So, wrapping up, I would just note that the competitive market in Texas is supporting renewable PPAs among developers and competitive retailers, and not so much in the east. We think that utility default service creates a lot of uncertainties and disincentives to retailers. To sign these agreements, you feel that what's going on in the capacity market looks an awful lot like reregulation and would stifle the benefits of competition and innovation and ultimately lower price to consumers, and hope that we could find a way to resolve that on the wholesale side. And if we could even develop Texas-style retail I think we'd have an even more robust market where consumers get to pick their generation mix. Thank you for your attention. I look forward to the Q & A.

Moderator: Thank you very much. That was very helpful. And now, without further delay, we'll move on.

Speaker 4.
Hello, everybody. I work in the business development group, developing wholesale generation projects. Specifically, I work on utility-scale solar. I have been developing wind and solar projects for most of my career, since about 2005. For the last three years, I've been focusing on building portfolio for ENGIE.

So here I’ve put up a bar chart that was issued recently from Bloomberg New Energy Finance. It shows what we've been working on mostly for the last several years, and then this is a snapshot. This is 2019. We've done approximately 540 in the US for solar. About two-thirds of those are in ERCOT and the other remaining third is in PJM, and we'll see those projects will come online for the next two to three years.

This is a slide from a chart from McKinsey on competitiveness that’s driven corporate procurement for new PPA. And what you're seeing here, if you look at that bottom bar, the green piece, the 19% is where ENGIE is most active. We do have some PPAs that we've entered into and really Municipal Utilities mostly in ERCOT, some in New England ISO. And that's going to be in the 73% range is worth noting that a lot of what you're seeing here is voluntary.

And that's really, I think the distinction between RPS-driven growth and then the yellow bars, some new activity you’re seeing in California with the CCAs. I think the CCAs are interesting, a lot of them don't really have credit ratings yet, but I think their self-mandated goals to procure more renewables will end up in greater credit quality as we go forward.

So this a slice of the utility PV outlook going forward. The forecast. And generally what you're saying is around 10 gigawatts DC being installed. It's worth noting that most of this is happening in California. Some in PJM, a lot in ERCOT, and then long term you're starting to see some utilities, for example, TVA, Dominion in Virginia and some of the Florida utilities are putting forward integrated resource plans to secure more solar. And then, I think, as the PPC for wind sets down, we'll start to see solar take up more of the pie in terms of new selection.

The next slide gives us a feel for what that might look like going forward. Here you see what was done in 2019, a pretty big year for new capacity additions. I think 2020 will be hopefully in line with what's there in the forecast. The thing that I'd like to ask in this chart is, what's going to happen? What are we going to do in ENGIE, in terms of continuing to meet demand when most of the corporates that we're contracting with have met their sustainability goals?

So most of the people that you're seeing sign voluntary PPA contracts, they're Fortune 50 customers, typically Amazon, Microsoft, your technology companies. And so, one of the things that we try to think about a lot is, what are we going to do when the corporates have met their goals? How are we going to serve the underserved, the folks that still may want to buy more renewables? And how we are we going to put those aggregation models together and what products can we offer?

We've got a lot of risk that we look at from both sides actually here in ENGIE. I work on the side of the house that puts together the generator side of the equation. We also have a trading arm that actually buys from generators and [UNINTELLIGIBLE] into long-term PPAs. So typically what you see is the price risk is usually the buyer is assuming, and sometimes, we're starting to see things evolve, where some buyers might be more comfortable with the index PPA to wholesale market price. There might be some callers. Then also, there's shape and production risk.

I wanted to just point out there's an error actually on this bullet point. There's an increasingly smaller pool of [UNINTELLIGIBLE] where production is**.** Generally, if you're a buyer you're wearing some form of shape risk, whether it's fixed or unit-contingentt. Then also there's, of course, which Speaker 3 mentioned earlier, there's the term risk generally, the buyer and when they're buying into these projects, that the more value that they see is within the upfront piece and generally there's there's less certainty, I guess, in the back end of the contract.

So one of the things you have in ERCOT that helps people at least get comfortable with the first seven years is you have a pretty long-data gas curve. So generally that goes out to seven years. And so when you're when you're a buyer and you're thinking about how much of the tenor of the time track are my my warehousing, usually it's beyond the seven years that you have to warehouse, so you know if it's 12-, 15-, 20-year contract that's the part where you don't have the the bright white light of the gas curve helping you to kind of get a feel for what the value is.

That's also one of the potential points that I wanted to bring up, there's a lot of tension, usually in negotiations when the buyers want shorter tentative generators to secure financing, we're going to do back leverage on a project. Generally, you want to have as long as you can go.

On the generation side we have here a pretty good list of risks. There's certainly more, but I will point out that a lot of what we're seeing here is from feedback that we get from the investment community, whether it be from equity buyers who we partner with on projects or if it's tax equity or perhaps even lenders. Generally, what we hear from them is a message that says, "We think the risk should be worn by those parties that are that are most suited to wear it. And so if you're talking about corporate buyers, their main business is not buying electricity on wholesale market. Whereas at ENGIE,we're an A- rated balance sheet, very large organization globally, and we have a lot of resources and financial tools to manage these risks better than then a lot of the folks that are on the buy side.

So some of the things that you'll see that Speaker 3 touched on these as well, is in markets with renewable penetration you'll see negative gamma, which is essentially with the covariance between your generation relative to the market and hub. So, for example, if everybody's making a lot of wind energy at the same time, what impact does that have on the spot market? What does that mean for the buyer, the seller? A lot of times you'll see the seller say, "Well, if the price on the spot market goes below zero, we're not going to take it." And so that's usually a curtailment event. Then there's your garden variety basis, your shape risk. There's the economic curtailment that I just mentioned. And then there's usually reliability current curtailment if things get really severe where ERCOT or some other actor might step in and curb generation.

So there's mitigants for a lot of the risk. You'll see an organization like ours will have our trading group and we'll buy FTRs in MISO and PJM, FTRs in ERCOT. I just want to make a point, though, that these are often used to optimize an asset, to manage apparent risk. And this is not going to make us whole if there's compounded or severe risk in a particular asset.

Another another way we can manage this is if we build and tailor portfolios, but setting new positions and these are often just very basic, simple terms of trying to figure out what you want portfolio looks like one day. Then there's regulatory risk. Oftentimes, if it's just natural financially setted PPA feel, you'll see the generator having to make, make sure that the Dodd Frank reporting requirements that we have in the contract. And then something else that's important is credit risk. One of the things that we see oftentimes when we're looking at kind of parties for PPAs for projects. Corporations they often have a whole spectrum of credit ratings and typically they're not as strong as your classic incumbent utilities. And that's okay from our point of view. It's a better fit for our business model and our strategy overall in terms of organization.

We think that this can help with aggregation models. So let's say, for example, you might have a Microsoft or an Amazon or Facebook as an anchor tenant. And they might buy roughly, 60% of the output or 50% of the output from a particular generator. Then you have some room there to work with, with other parties. But the main point is that you have two parties, the owne—the generator being ENGIE with a strong credit rating—a large Fortune 50 company that presumably has a strong letter of credit rating so that low cost of capital brings some the power to cost of energy for all the parties involved.

Then one thing I'll just point out as something that's kind of an anomaly to me and we don't really have the answer for it, but we work a lot in ERCOT, and it's interesting because there's a lot of virtual power purchase agreements that are just purely financial financially settled. And it'll be interesting to watch what happens if these are continuing to grow in volume in the market, a lot of the energy this produces is actually never scheduled to meet load. And so this will be something to observe because renewable penetration continues to grow.

And then down at the bottom. I put classic owner risks: development and construction, operations resources that you know typically go along with owning a power plant. Here, I put up some some questions and some observations. So in markets with competitive deregulated wholesale, retail markets, I will confess, I'm not really an expert on the retail market. But we do have some businesses in our organization that worked on behind-the-meter applications for solar residential, not too much, but certainly with smaller C&I customers and larger C&I customers. It just might have smaller applications for onsite generation and usually one of the bigger barriers is optic or credit quality for long term PPAs.

That's always the question, and one of the things that, being in renewables for a long time, that you know you have to work with their tax equity partners. Tax equity, on the one hand, it leads to a lot of renewables being installed. I don't think there would be near the volume installed that we see today without them. But on the other hand, it restricts the pool of capital and investors to those that have income tax exposure to hedge. And so in some ways that's a restriction. Then also, one of the things we've discussed the PPA term length willingness, the volume means relative to upfront capital requirement**s.**

To get back to serving the underserved, we tend to think of things in a variety of different ways. You can contract with existing assets you know where the initial PPA term has expired. In some cases, these might actually be at higher prices because they're the older technology than would be if it was with a new asset. And then there's the customer aggregation models and there's various ways you can be good with that. You can do many customers, one project, many customers, many projects. And then there's, which has been mentioned, the city's municipal utilities.

One of the things that's kind of interesting. We have two PPAs with two major cities in the US for solar projects. One is the city of Houston and ERCOT, and then the other is with the city of Philadelphia and PJM. That's that's something we we like to see ourselves continue to do, to serve cities. We see them as good customers and we see this as an emerging area, obviously not all of them control the load of their residents, but they do have often pretty sizable load just from its facilities if it's a major city.

So one of the questions that a colleague of mine in our government regulatory affairs has helped me to kind of think about was community choice, clean choice aggregation. One of the things where there's debate about in our organization is, is mass adoption of renewable energy more likely to happen if people have to opt out like they do currently in San Diego? Or is it going to lead to more going door to door, asking everybody to buy renewables affirmatively? And so that's one of the things that we, as an organization, I don’t think we have consensus on, but it's certainly interesting to observe.

One of the questions in the panel is about level playing field. I will say one of the things that we definitely support are long-term contracts between voluntary parties—corporate PPAs and [UNINTELLIGIBLE] party PPAs. I think one of the things that that we tend to shy away from is the model where you have the incumbent utility buying default services. We think that those can lead to some costs that oftentimes end up back on to the ratepayers for charges. So that's something we tend to shy away from.

And I'll note it seems like there's oftentimes a lot of discussion, do financial participants, lenders, equity investors, do they support distributed renewables or are they just supporting large volume buyers and wholesale generators? I'll say that I think it's interesting to note that if you're talking about rooftop residential or [UNINTELLIGIBLE] residential, you know, oftentimes it just, it takes longer to get to scale. So for example, we recently did a equity sell down with with Goldman Sachs for 200 megawatts. And I believe that's right number for distributed solar PVI applications, most of these projects are under two megawatt nameplate, and it took an organization of 75 people in terms of headcount and two to three years to put that together.

Whereas for utility scale, we're doing approximately 500 megawatts in solar and 700 megawatts in windyear and the headcount for both the wind and solar teams in ENGIE is around 50 people. So it's just a difference. And you know how long it takes to get to scale. I will say there's definitely interest from from the investor communities to do both. And so that I believe is the last slide. Thank you.

Moderator: Thank you. We've come to the end of the formal presentations. We're going to take a short break and come back for Q & A at 2:40.

Discussion.

Question #1: To achieve state goals, it occurs to me that in regard to Texas there's a very great advantage, where there's a tremendous opportunity for sellers because of the sunshine, a tremendous opportunity because of the wind regime. And, of course, the state basically socialized $7-9 billion worth of building of transmission lines to bring the power, all the way from West Texas to the load centers.

And obviously, in other parts of the country, in the east, they don't have those same advantages. And so the states have basically said, "Look if we're going to really ramp up our level of renewables, we just have to bite the bullet and essentially have a separate auction. Put it on the ratepayers and absorb a level of subsidy to that."

So I can understand how maybe different people can think of different market structures, but it seems to me that as long as the states, and certainly they're right want to very materially increase the level of renewables, they essentially have to find a way to put subsidies into the pot and and therefore have a broader market mechanism where everybody else could participate and choose their preferences and so forth is unlikely to go very far, given what has to be done and the states' very strong desires to see the material ramp up or renewable energy. I'd be interested in any comments on that.

Respondent 1: I'll jump in on that and appreciate the comment. I hear what you're saying. I know that if you're a regulator a policymaker in the legislature, it looks like it could be solved by the tools in your belt the right, regulation or legislation, but my contention is that you get more innovation and lower costs and more creativity out of the developers, if you can go to a market mechanism like the capacity auction, something similar to that would incent new generation.

So just a couple of more details, if I could take a moment to talk about it. We were picturing forward auction, it would be three years forward, similar to capacity auctions in the east. So that developers have time to bring a project to market. It would have a seven-year price lock for new resources. There would be a purchase prior to delivery that could be an incremental auction similar to, what some ISOs in the east hold to true up positions. But we think a market mechanism like that is going to bring more creativity to the process that rather than direct contracting by state.

Moderator: Other members of the panel want to respond?

Respondent 2: I'll jump in. Obviously, the state of New Jersey has subsidies, if you were to call them that. We don't. And we've got the renewable portfolio standard, we have an OREC mechanism for our offshore wind, we have the zero emissions credit program for our nuclear units. Then we have a whole plethora of additional incentives for various renewable and clean technologies through our Clean Energy Act of a few years ago, and I guess what I would put forward is, notwithstanding all of that legislation, the board is still very much interested in exploring these alternative mechanisms to find a way to achieve the best outcome at a lower price.

If that does require us to change the regulatory paradigm or to explore new legislation, part of this investigation that the board announced on Friday is exploring those very topics. And so if our current regulatory paradigm, as kind of embodied in the legislature's various statutes that really are entrenched in these subsidies, if you will, if that's not going to work to get us to our ultimate goal of 100% clean energy at an affordable or reasonable price, then the board's interested in comments on alternative frameworks.

Questioner: A quick follow-up question. Just, I guess, in terms of this sort of specialized market for renewable energy, Speaker 3, can you talk to the idea that this would be run first and then after it's been run, then they would essentially be the capacity auction that we otherwise seek? Because it sounds like one has to follow the other. Otherwise, you don't you don't know what you're going to be getting.

Respondent 1: Well, I think, just as you have multiple revenue streams to suppliers now through through REC**s,** a project can be awarded a capacity contract alone for renewables, if they build 1000 Meg wind farm, they might have a much smaller proportion that can be sold as capacity.

But just as they get a revenue stream from capacity or from RECs now instead of RECs, they would be through the clean energy market.

Respondent 3: I'll chime in. It's a great question. I think the way of internalizing the externality is a separate, inseparable question. I think you could use a carbon tax, you could use a renewable portfolio standard, you could use a clean energy standard or do other things, if you're a state. And states do have this authority, of course. I think the market structure and design can operate effectively on top of that, or in partnership with that.

Witness Texas. Again, there certainly are incentives at work. Their investment tax credits for solar and production tax credits for wind have a significant influence on deployment of resources in that state. So, yes, the RPS has long expired, but the incentives still remain. So I think the important thing is to get wholesale price signals that reflect value, taking account of whoever might be supporting different resources coming into the market.

Probably best not to get into the whole MOPR and buyer side mitigation question on this panel that can take over every conversation.

Questioner: Been there.

Respondent 3: Yes, indeed. Me, too. But I would say just on the idea of the FCEM proposal, the centralized procurement of renewables that under the current FERC theory that is driving the broad MOPR and buyer side mitigation. That would almost certainly be MOPRd as well. So I don't think that's any way out of that situation.

Question #2: Hi, folks. My guess is people will not be surprised that my question is about financial transmission rights. I’m wondering whether the ISOs should continue to facilitate markets for congestion by offering the transfer capability on the system as FTRs. All of the ISOs do this, but in PJM the market monitor has suggested that that's not a good idea, that the congestion wrench should be directly assigned to load.

And I think one of the things that gets lost here is the ability for generators or renewable entities in this kind of market structure to be able to hedge their basis risk. So I'm curious about comment on that, and then a second question is, what is the role of long term FTR and CCR markets as they exist in PJM, where they have them two or three years forward, and does that help with transparency with respect to evaluation of where to locate renewable generators and also liquidity, in terms of providing price signals and helping with the hedging, providing for markets that allow market participants to hedge congestion risk around that? Thanks.

Moderator: Any of the panelists?

Respondent 1: I can try to maybe give some light on this. When you're a generator and you're proposing a new renewable project, one of the things that is just in the toolkit, are FTRs and CRRs. And I would say that these tend to be not necessarily viewed as something that goes into the underwriting of our projects. Certainly, we do basis studies forecasts. Most of them are wrong. You hope they're right after you build the project, but there's a variety of factors that can change or make worse or alleviate congestion around a particular node.

So those are things that I would say if we could get longer visibility on those types of products, I think it would certainly help. But when you're talking about underwriting a solar project that has a useful life of 35 years, and if you take the full price on CRRs in ERCOT, for example, and you show those to your banker, they don't care. It's just a mitigant if for some reason you're in a congestion on the wrong side of the congestion plate and you need some help with managing basis to help.

Respondent 2: I would just add that I agree with the comment. I think that if you're building a project, transmission is unlikely to be such a disadvantage. You wouldn't consider the location if you can't get the power out. And I think if that were the case, you're probably already gonna have a price signal that that node’s not a financial location for you. In general, FTRs are going to be a shorter-term instrument when you consider the life of a project. I think they do give you some visibility and transparency and help you at least calibrate the early part of your modeling, as we mentioned, when you build a model, you know it's probably wrong. But at least you can find out where people are putting their money. So I think it's a helpful early indicator it's not going to help you in the long run, a finance your project. It’s almost a separate consideration.

Moderator: Next.

Question #3: So my question is more on the discussion around the default service. And I think the general theme of some of the presenters, and thanks for your presentations, were it would be far better if we had retail competition among all consumers. But I wanted to ask, so we really probably aren't going to have that anytime soon, it seems, because a number of the states certainly are fairly embedded in their default service models and while I do think you could see changes in the way of making the product less attractive, I'm not sure they'll make it so unattractive that everyone would switch.

I'm curious, if we're talking about financing of renewable projects, which I think is a big theme we're listening to here, wouldn't it seem that the default service models that are in use right now actually are providing through the utilities that are actually the wholesale buyers this sort of certainty and creditworthiness? Granted, they are representing a whole group of smaller customers and are registering their demand, but they're stable structures. We heard about BTS structure and I'm just wondering if the industry's kind of revertically integrating in a competitive way, no longer through a monopoly cost of service regime for the generators, might we be making some progress if we have the right types of requirements for renewable energy resources, where we'll actually be able to finance some of the projects by the wholesale suppliers themselves taking on the some of the risk on behalf of consumers through the creditworthy utility counterparts?

Respondent 1: I think you're asking using the terms we used in the paper I described. You're asking whether essentially the hybrid model can work. Hybrid being, having a default service and a segment competitively served. And I think it can. We propose a number of specific fixes in our paper to make it essentially so that the market size was known by the retailers and that they just had normal business risk. If you're in a normal business and you've got competitors, you know that you might lose customers to your competitor, but you don't usually have this situation where a whole segment of demand can just depart with a free option to go to this other advantageous situation.

So that's what we're trying to protect against and at least stabilize the market size. I'll see if other panelists want to comment.

Respondent 2: I'll just add that the regime where you see New York contracting for specific projects, for instance, and using T&D rates to recover them, it does get green built. No doubt about it. But the state is picking winners and losers, and requiring ratepayers to live with those decisions for the long term.

I think you get a more robust mix if you can restructure that utility default service scheme and you have shareholder money more at risk than ratepayers on the hook. But you're right, it's an uphill fight.

Moderator: OK, next.

Question #4: This is a question about default service, and I understand the reasons for it originally when there was uncertainty around the whole notion of retail competition. I guess my question is, what's been the biggest impediment, now that we've had 10-20 years of it in different jurisdictions, to move away from default services, just is that the pure political power of the utilities? Are there other issues that work to keep default service in place in the other jurisdictions?

Moderator: A nice, unloaded question.

Respondent 1: I'll actually respond to that question, and the question before. I do think that the board is open to modifications of the BGS and we would kind of welcome that. But it dovetails with this next one which was like, well, wasn't basic generation service created as this introduction to retail competition with the expectation that maybe we would move away from it? Absolutely.

That was how it was crafted, even in the legislation that was on the slides that I provided to you today. I can't necessarily speak for the commissioners. I think it's something that works in New Jersey, and it ratepayers affordable prices and the commissioners are loathe to move away from it. I don't necessarily, at least in my personal experience, feel that it's a political experience, but maybe I'm not high enough that I get that political pressure.

But I do think that it is something that works. And I did have a quote on my slide that's something that was in our 2020 board order approving the BGS auction for this year, that kind of talks about how it has worked and it has been successful and even our ratepayer advocate, which we call the Division of Rate Council in New Jersey, they speak favorably of the BGS construct. So there's a bit of a paradoxical viewpoint in New Jersey, where we believe in retail competition and we want it.

But we're also very much enamored with our BGS structure. So there's a struggle there. I'm not gonna lie.

Respondent 2: I'd just like to add, I think it is whoever has their name on the bill has a closer relationship with the customer. So, in Texas, we have supplier-consolidated billing when I saw the question, that reminded me our biggest state for natural gas is Georgia. We have supplier-consolidated billing there.

So we really do appreciate that. But you know when there was a political push for the utilities in New Jersey to have to get zero emission credit ZECs, there were TV commercials running around here: "It's the name you know and the people you trust." There is power in having that relationship with the consumer, so I can see the push to keep utility default service.

Respondent 1: All right, I'm just gonna jump in and say that the ZECs were given to the unregulated affiliate so they shouldn't have been saying that that's the name you know.

Respondent 2: Let's see if I can find the commercial on YouTube.

Respondent 1: Hey, they also had a full-page ad with seven of our former governors signing it that was, again, the unregulated affiliate.

Moderator: Next question.

Question #5: OK, I want to take this discussion both on the customer side that we just talked about, and also ask a question on the supplier side. As a former regulator, I'm always troubled when we as regulators are stepping in and either making decisions for customers or socializing risk.

We did declining cost options when I was on the commission in Ohio for basic service. We did it in large part because we didn't have the metering to be able to enable us to do any sort of market-based pricing. That's changed in a lot of places. Today, we know that customers actually pay more in a flat, BGS-type rate because the suppliers are facing a combination of correlated price and quantity risk to give you that flat price.

We know that there are other ways of handling that, whether it's through more active demand management, whether it is through some form of loan or budget billing program or some sort of block-and-index pricing, that is common in commercial industrial customers. All at potentially lower costs. Take Speaker 1's example of Go Griddy. Their prices, at least if you believe what they're putting out, are 20% below the average price of fixed contracts in Texas. So I guess on the the customer and commission side, I'm curious about what you think the barriers are to something that moves us more to a market-based dynamic price and gives more choice to customers about the extent to which they want to hedge risks that are good for them?

Going to Speaker 3’s presentation, I'm wondering, what is the real role and how much value is there in the seven-year contracts? I can see the value of having more stable, more broad geographic basis for purchasing clean energy, but would you be in a similar place if we had a broad regional clean energy, REC-type market, rather than this kind of forward contracting market? So let me ask both of those questions, both themed on how much should the regulator intervene.

Respondent 1: The theme of how much does the regulator want to intervene—you actually asked a lot of questions. So I'm trying to make sure I take them all in turn. To the extent that New Jersey is pretty comfortable with our BGS construct, I don't necessarily see it going away. I certainly don't see it going away quickly. But recognizing that we do see value in retail competition, we have been trying to get more of that.

I'm going to have to agree to some extent with Speaker 3 that one of the obstacles toward getting more of that competition is that there's an element of sophistication that has to come into play when when customers are shopping and there's a relationship that's established with the bill and that, yes, parties are comfortable with PSE&G and, putting aside my joking about the [UNINTELLIGIBLE] legislation, I guess our concern is that we see a value in increasing renewables and if that means that we are going to be transitioning, then we're open to new and innovative solutions, and so that's actually what we're actively looking for at this time. And I think I only answered two out of your three questions, but I apologize. I think I forgot the third one.

Respondent 2: I'll chime in on the first part over here. That's a great question, you know a lot more than I do about retail design and, I agree, getting towards a more market-based approach on the retail side and allowing more dynamic pricing would be beneficial and similar to the earlier question, moving more towards more people in the competitive market would be beneficial and efficient over the long run. While I also recognize that for many consumers, they really just don't want to have to pay attention to this stuff and want to just pay the bill. And I respect states’ choice if they want to do a large BGS type of procurement on behalf of a large group. There's certainly some justification for that. I would just focus again on making sure there's not a bias and making sure that doesn't undermine the competitive retail market and lead to a situation again where you don't have entities with the incentive and ability to procure power on a long-term basis. Because I get back to, how does this all flow through the chain towards investment? Because we do, I think, all agree we need a lot of new investment, especially if we're going to change the resource mix. So we need to make sure that that that chain is unbroken.

Respondent 3: I think I would just add to the last part of the question of whether a seven-year fixed price agreement is long enough. I’d just say there's a price that gets every deal done right. So I think a seven-year renewable payment on top of capacity market payments, on top of energy market payments, it got capacity projects built. I think it would get renewables built. I'm sure it would get renewables built at some point. It also has the the benefit of not saddling two generations of ratepayers with contract costs, if you will, right years as a reasonable term for homeowners to pay for a project and then the project is there and if we need more, then you can buy other tranches but you're not if the longer you run these these costs out it gets expensive fast on the back end. Right.

Question #6: I guess my question was more, could you do shorter term rather than a REC or a ZEC market, not suggesting we do longer but can we can we get away from doing the seven-year? Because you seem to like the Texas market, which doesn't require that kind of intervention.

Respondent 1: We actually are signing deals in Texas of seven years or longer, so what we're finding is, if you want a new project, I think that's the minimum that we've seen to get a new project built. So if we could do shorter, we'd love that and maybe we get there. Panels get cheaper. It may be possible. But right now, that seems to be the magic number. That's why we're there.

Moderator: Thanks. Anything more? So many questions, there must be something you wanted to address.

Respondent 1: I feel like that was pretty comprehensive from the other panelists. I didn't have much more to offer.

Moderator: Okay.

Question #7: I do have a question. Although I have to preface with just a snide comment that I always enjoy allusions to a reliance on on the distinction between regulated and non-regulated affiliates, which gives fig leaves a bad name.

But moving on beyond that. My question goes to the FCEM presentation that Speaker 3 made and you know we've seen this before and I see that Travis is also on the call. So, he could probably comment to this as well. And I guess the question goes to the status of that proposal versus the question of either a region-wide or preferably a nationwide social cost of carbon pricing regime.

And, like a number of approaches to internalizing externalities, whether it's the FCEM you've proposed or its RECs and RPS is or whatever, they do all tend to amount to a second- or third-best solution, right? And I know it's not a binary question, carbon pricing will have one effect if it's $2 a ton, have another effect if it's $50 a ton.

But I guess the question is, if we get Speaker 1's proposal right, and most of you will know that I'm a big fan of that approach, and we add on top of it a proper social cost of carbon pricing regime, can we foresee the kind of successes that even Speaker 3 referred to in Texas, where the market steps forward and provides a sort of variety and spice of contracts that investors are going to need, rather than relying on the moral hazard of assuming that regulators and states are always going to step in and undermine incentives for the market to be efficient?

Respondent 1: Okay, so I think you started with the status of the FCEM proposal, so if my colleague can jump in, I might invite him to do that because I'm usually on the trade floor.

Comment: So we continue to work on this proposal and I first agree that the combination of a Texas-like retail market, together with a policy that internalizes the carbon externality, would be our first best. But everything we hear from policymakers, especially in the bluer states that are adopting aggressive clean energy standards, is commentary that, well, maybe we do a carbon price, but we wouldn't want to give up these complementary policies. And in fact the complementary policies when applied to the power sector end up being the binding constraints, because they're more directed, they're more stringent than the carbon prices, which tend to be lower cost and technologically neutral.

And so our forward, clean energy market proposal is really an attempt to introduce more market principles to those RPSs which we see operating mostly to just commandeer the T&D utilities, which in those restructured markets don't really have any incentive, except maybe a perverse one to manage the costs of those renewable procurements. So that's really, if you've boxed yourself into a future where you have a default supplier that has strong incumbency and you're not willing to really reform that, and you're not willing to adopt a carbon price that's stringent enough to do the hard work of decarbonisation for you, then, yes, it's an n^{th}-best solution. Let's optimistically call it second, but it might be the third or fourth or even fifth. You should consider adopting a market based approach for your RPS which forward clean energy market represents. Speaker 1 pointed out earlier, how do you make it so that it's not a state subsidy?

We hold out hope in the kind of cooperative federalism that has marked this industry for so long, that states might direct that market through the demand they put on RECs and default utilities for a certain percentage of renewable or clean energy procurements. But then it could actually be embedded within the tariff of an RTO, which would make it definitional being not a state subsidy. Even if states were to hold essentially the level of control over that policy.

So that's some of the current state of thinking, but again if we could get New Jersey on to a Texas-like future, then I don't think you would see us advocating some of the more I guess what I'd call pragmatic fixes that we've stepped up and tried to identify.

Moderator: Any other comments from the panel before we move on?

Respondent 2: I had one comment. I'll just talk about what's going to put the most renewables on the ground. And having a lot of experience where it goes in ERCOT and the Mid-Atlantic, one of the things that we see in RPSs in solar is a cap on the size of the projects. So, for example, in New Jersey you oftentimes you see five megawatt cap. These are easily scaled projects and to us, that's really pretty limiting in terms of how much we can try to make gains for and economies of scale and size of our projects. It's understood that there might be land use limitations for smaller states versus Texas, obviously, but it seems like whenever there's an issue in New Jersey, where there's possibility that the goals may not be met, in terms of the RPS they tend to lift the caps and that that's another source of volatility in REC prices and in trying to just get stability when you're trying to underwrite, decide where to develop and invest in putting your projects so that's what I wanted to mention on RPSs.

Question #8: This is mostly for Speaker 4. But I appreciate hearing from others, as well. You talked a lot about corporate buyers and serving corporate buyer needs. Are there states that you can't serve those needs in or, I guess, are there states that are hard to serve their needs in? And, if that is the case, is it improvements at the retail level that give those corporations access to the product they desire or is it improvements at the wholesale level?

Respondent 1: It's really a combination of both. But I would say mostly, if we're talking about, a Fortune 50 profile customer, they oftentimes will have a footprint across the country and various states. If you were to see where they're doing most of their contracts, it's in the deregulated wholesale market, so PJM, ERCOT, etc. Whereas, if you take SERC, for example, Southern Company’s balancing authority, you see really things are gated by the incumbent utility. So you can't do a bilateral agreement with a corporate buyer in Southern Company’s balancing authority, unless you're in one of the municipal utility territories, if you're connecting to any of Georgia Power’s transmission lines, they have a law that restricts your ability to sell power at wholesale level, so that's typically the biggest barrier for large-scale installations. Then, if you want to take Virginia as a subset of a place that has deregulated wholesale, regulated retail, that's a place where you know we can contract with people that own data centers, Amazon Web Services, Digital Realty, Microsoft and many of them do own fasteners in Virginia, by virtue of the fact that a lot of the fiber optic cables just happened to run through the state, but they really can't directly serve their retail load for their data centers, unless they go to the regulated utility, which is mostly Dominion.

So, to answer your question there, it's not end to end, whereas in Texas ERCOT we can make the the contract work all the way from wholesale generator and then we can sleeve it through our trading partner in-house and ultimately what we can make it look like to the buyer is just like regular retail. And they really like that.

Questioner: Thanks. I'm definitely interested in hearing from others, essentially, I guess what's your perspective on corporations who are seeking renewable products, who can't access them either because the utility doesn't have the capability to provide it or they don't have a market in which they can access it.

Moderator: Well, I'd like to follow up on that and actually bring it back to an earlier question about what to do about subsidies. The thing which I find worrisome about these conversations, and it comes up in dealing with exactly that sort of issue.

Let's take the basic generation service in New Jersey. One of the most attractive features about that hasn't been mentioned in this conversation, and that is that a basic generation service for delivered energy. There's no identification of who produced. There's no attempt to identify the generators that are connected to the customers in New Jersey. It's just delivered energy and that's a good thing because that's reality, that’s all we actually know. All the rest of it is fiction when you're talking about this generator is supplying that customer.

So when you're trying to set up a system, particularly with subsidies, and what I have implicit in a lot of these conversations, particularly with long-term contracts with those generators, so they can get the money to go invest it, too much of it worries me about recreating the fiction that this generator is supplying those customers. As opposed to things like renewable energy credits, which are effectively unbundled from the source of the generation.

So you could have a requirement to New Jersey that customers have to buy their delivered energy, and then they also have to buy renewable energy credits that meet whatever standards. And they have nothing to do with each other on a day-to-day basis. They’ll have an interaction to the long-term market, but they have nothing to do with each other.

You can handle subsidies and state requirements in a way that is compatible with the market, which, I would say, is the REC story as opposed to doing it in ways that are going to unravel the whole system, which is long-term contracts with individual generators. And I don't see enough distinction here in that conversation. Maybe I'm missing something. But I think this is a potentially a rather big problem. And I'd be interested in the comments from the panel or anybody else.

Respondent 2: It's a good point. It's a grid, right, the power goes everywhere. I get that. We're seeing more and more customers want to say that I'm getting my solar power from that project on the street or we see commercial customers that say I want a project that I can point to where I'm getting my green power from, that makes it more real for my purposes. And this is this circles back to the issue with RECs.

One little thing about RECs is if you put solar panels on your roof and you want to sell your RECs, you can't tell people that that solar panel is powering my house. As soon as you've done that you have claimed or retired the greenness of the power. It's now not available for sale in the market. We've come across this issue and and a number of places where you do truly have to separate the greenest of the power from from the source of the power.

So when a customer says I want to be able to point to a project, it's great to have a contract. You're right. You can get it through X, it's just more complicated at that point. As long as you're going to get power at a price that you like at a term that you like and it has the green attribute that you like. We're finding that very workable for us in Texas.

But you do raise a point. In the east, we've had this issue where some of our brands will go to a project, we're going to buy some specific RECs, for instance, for our Green Mountain brand, and we find out that the developer has made claims that, “Yeah, I've got these panels on my warehouse roof, and they're powering my facility.” We now can't take those RECs, for our purposes, they've been retired, for all intents.

Respondent 3: I will agree with you on the public policy objective of better integrating the physical power service with the financial REC/incorporation of environmental externalities. I do agree it works well in Texas. It is all integrated. You have the unbroken chain of transactions from the generator down to the end-use customer, and that includes their consumer preferences. If they want 100% renewable energy, they can buy that. And the retailers go out and procure that. But the retailers also need to serve them at 8pm at night and they have that obligation as well. And they also need to serve them where they live, not just those in West Texas. But wherever they are. So I do think the Texas model does stand as a fully integrated example where it all works.

And I know it's that's very different from my state in Maryland, I am served here in Bethesda, Maryland by RECs that include Indiana and Illinois wind farms, and this gets back to the question. There are a lot of corporate energy users who have ambitious clean energy goals. And I think that's great. And we should have markets that allow consumers to buy what they want to buy. But not all the corporate energy users are behaving as Google is. Google is trying to match up by time and location its energy production with its consumer load, its data center and other load. And they are really more the exception than the rule.

Moderator: And the Google model will cause a system to unravel if everybody does it.

Questioner: Well, they're deploying their AI. So maybe the system will run perfectly, I will just say. I think they're they're leading. Google's the leader in trying to trend towards that actual physical tracking.

Moderator: We've been there. We've had this conversation. You can do anything for a small fraction of the market, but when you try for everybody that way, it just doesn't work.

Respondent 4: I'll jump in, because this is another example of where New Jersey's kind of pulled in opposite directions because obviously we have the more unbundled traditional REC that you reference to build. But we also have more recent legislation that has created RECs, whether they be ZECs or RECs or look a lot more like the long-term contracting that you're referencing. And what's interesting is that there's there's recognition of this conflict in our energy master plan and internal to the BPU, just speaking as staff, not on behalf of the agency. I'll say that that staff understands that there's an internal conflict here and and that's part of what we're trying to resolve ourselves and try and figure out the best way to move forward because there are some staffers that do definitely see some value in that long-term contracting to get to the clean energy goals.

But then there's a long history in New Jersey for support for competition, and you see that even in our orders and filings today. So it's trying to reconcile these two competing interests is something that we're definitely grappling with from a policy perspective.

Moderator: OK, next.

Question #9: Great discussion. So my question is about regulatory risk and comparing sort of the first-class climate policy to the forward clean energy market idea. So I've done some research around clean energy standards, broadly, but they typically don't talk specifically about a forward market and they're kind of manifested or modeled, at least from our perspective, as a spot market. I'm just wondering if the people who sign these contracts and people who actually develop clean energy projects see more or less regulatory risk across these different approaches.

In the fictional world, if you will, comparing, as we have done an analysis at RFF, a carbon price for clean energy market that achieves the same amount of emission reduction. Is one more risky than the other, from the perspective of the developer and is that a consideration?

Respondent 1: Thanks for that question. I'll try to answer it. So when we're looking at projects that we can make an offering to a buyer for long-term purchases, really what helps to get the parties comfortable isn't necessarily the RECs or an RPS mandate.

I think if you look at California as an example, they kind of dove into their goals without really kind of thinking about, what kind of transmission do we need for this long term? What should we do with if there's overgeneration, the proverbial duck curve? So I think what would really be helpful is if you had a broader program. I tend just personally to point to, if there was a carbon price, the carbon tax, if you will, I think that would be pretty reliable.

But we're just talking about Texas projects or even PJM projects. Really what helps us to get comfortable with the PVA is the forward price of energy, of electricity. And then, in some cases capacity, if you're in PJM. There's some certainty that you can take in the first few years that I discussed, where you have a gas curve is gasis on the margin in both of those markets. Now, this might change if renewable penetration is high enough to where gas is no longer on the margin is dead. There might be some more seasonality, depending on what rate of renewable penetration there is. And then I would say that value proposition, where you can work with long-dated curves in those markets, West Hub in PJM, for example, is the most liquid long-dated hub in North America. And so when I can take a project**,** I can say our price for the next 20 years will be this. Then it's a pretty straightforward decision for them to say whether or not they're comfortable in engaging on the other side of that.

Respondent 2: A lot of folks here deal with models a lot, that don't deal with economic risk management or other forms of risk. I think there's an argument to be made that relying on many buyers, as they do in Texas, is lower risk than relying on a single political entity. So the STEM or some other RTO centralized procurement type of structure means everything is kind of relying on one entity.

And if that changes, then the whole market changes, whereas if you've got dozens of wholesale buyers, as you do in Texas, then what happens to any one of them doesn't affect the whole market. It's the classic, how do you manage risk? You diversify. So I think a many-wholesale-buyer model is less risky than a single-wholesale-buyer model.

Question #10: I guess I just wanted to return to this thought about the subsidy and the way you talked about it, Moderator. Certainly at the ISOs we're in favor of a carbon price as the mechanism we'd like to see in a market-based structure to encourage renewables. We have to grapple with what we have, which in the case of New England is basically these state procurement systems. And what strikes me is the thought of just trying to get them instead to think in terms of expanding the RECs is somewhere as a hybrid moving along the continuum, where I guess that would not be something that would arise to a MOPR, yet would provide additional revenue to those assets so that they could effectively bid a lower price and still clear the market in the capacity auction, and thereby get capacity market revenues.

And I just started playing with that idea and wondering whether that's something that can potentially have some political traction, that would be a half-loaf to all parties of some sort. But it certainly so far in any way in New England, is not something which has been grasped, because there's been such a keen interest in promoting specific projects and feeling they had to have a long-term contract to support it.

Speaker 3, I would take it in your mind that seven years is pretty much the Holy Grail there, right, so you need that or you don't get it. So I don't know if you would count on RECs as being adequate for your purposes to get new renewables built.

Respondent 1: Well, we're on the buy side, not the build side so much. But, yeah, we found that seven years seems to get projects built and, as I think we've talked about in some of the Q&A here, if you've got an energy revenue source, a capacity revenue source and a reliable green energy attribute source, I think we can get a lot of projects built. I think we have a sustainable process for turning over the generation over time to something that consumers are looking for.

Respondent 2: I would just say, and I guess I'm going to violate my own rule of not getting into MOPR too much. But if the system operators need something then buy it, and pay the competitive price for it.If you need power, and if solar isn't giving you that, then pay for it. Prices get quite high in California at 8pm as they should. So focus on the reliability service that is needed and pay for that, and states can do what they want to do under their jurisdiction.

Comment: That's what we do.

Respondent 2: But there's also MOPR so—

Moderator: My concern is that the state procurements, these procurements that are they're thinking about, is we're buying power from *this* power plant is going to create all kinds of operating problems or they're going to end up where these power plants aren't producing following the Google model.

And then the whole system is going to be under all kinds of pressure to do something to change. I mean, it's basically trying to rebundle the unbundled service without the monopoly and then replacing the monopoly with the RTO or something. You just can't have a lot of competition and have this fiction that *this* generator is serving *this* customer, because it's not true.

Comment: I agree with that.

Question #11: I'd like to return to this issue of seven years. I spent a lot of my time in Europe, and they're just starting to go down this rabbit hole of capacity markets that we are hopefully trying to get out of in the US. They've leapfrogged the whole discussion about what it takes to get new generation built, they just seem to assume that it takes 15-year commitment periods for new generation. And that's what they're handing out.

In the meantime, I'm fond of pointing out that there have been tens of gigawatts, probably more, of new generation built in PJM over the past 15 years. And everyone likes to say, "Well, look, because they've got a capacity market." The PJM capacity market hands outs rolling one-year commitments. It is not the basis for a long-term financing and generation, something else is going on and PJM and whatever it is, one-year rolling commitments for capacity seems to be working. It doesn't work for renewables at the moment, for a number of other reasons, but there's no reason that those those problems can be addressed.

I really struggle with claims for how much the developer—and I spent 25 years as a developer of private power plants, so I'm not just whistling Dixie here—and I just struggle with these claims of how much of the developers' job people feel that consumers have to do in order for them to make a buck. I don't buy it.

I think that if you want to have things like an FCEM or an RPM in PJM, I think you can do the minimum and PJM does the minimum, at least in terms of commitment periods, and it works. So I really want to push back on that, and I'm happy to get into on a food fight over it. But I think the data supports my position.

Respondent 1: You're saying a year would do it. You got any projects for sale?

Questioner: I developed close to 800 megawatts. Sorry, I got 10,000 megawatts of private sector power projects over the course of 15 years and I did it with all sorts of arrangements and all sorts of offtake contract arrangements. This is not just an academic exercise.

As soon as you get seven years, it may not be you, it might be Calpine, it might be somebody else. But the very next day, somebody's going to say, "Well, seven years, gosh, that raises the cost of capital awfully high. Would it be better if we got 10 years?"

And then you get 10 years, and before you know it, you're in Europe, and people are saying it's got to be 15 years. Poland is going for 20 years now. So I think we need to look at what we've been able to get done with much more minimum ask for consumers to take long-term market risk off the hands of investors.

I think it's a bad trade in most cases. You're foisting on to consumers risks they do not understand and have no opportunity to manage, and to some extent that's the way the market works. A market works such that consumers and investors engage in that dialogue on an ongoing basis, but stepping in with things like an RPM or an FCEM short-circuits that dialogue and basically foists by fiat long-term market risks on to consumers. I think we need to be very, very careful about doing that.

Respondent 1: Right. Obviously, I don't know enough about the variables of the projects where you did something much shorter than that. I agree. We don't need 15 years or 20, if they're doing that in Europe, we find that seven works. And that's not a magical number. It's a number that’s working right now. So I think it's a good starting point. Shorter would always be better. But when you put all of variables together, we think that's a good place to start and we’d love to see it get shorter. I just find it hard to start much shorter right now.

Respondent 2: I'd like to add, I'm on the other side of this, where we typically see lower cost capital for longer-term contracts. And I'll say part of this is the investment community, the folks that we partner with, sell equity with. They don't put a lot of stock into the merchant curves once you go 10-15 years out. There's a lot of uncertainty in that. What we try to present maybe a middle ground. And keep in mind these are not thermal assets, these are rules where your costs are and your topics are all up front. If you can get your simple payback during the contracting period, that seems to be a good middle ground, I think, for buy and sell sides.

Questioner: I get it. I know anything that makes the developers’ job easier. But it's not a question of what investors want, it's a question what investors need. And it's a question of balancing the risks that investors take with the risks that you're asking consumers to take. Seven years is an interesting number, because if you look at the financial model for the typical combined cycle plant, given the time value of money, actually, it turns out that somewhere in the neighborhood at 80-85% of the expected return of and return on capital ends up getting made over the first six to eight years of a model.

And you can accept a lot more risk on the revenue streams beyond that. I'm not saying that there's no magic to the number of seven years. It's actually doesn't surprise me that that number pops out. So to go back to PJM, somehow even in PJM the market is filling a gap that the RPM clearly does not serve. The RPM clearly does not provide an adequate basis for the financing of a long-term power project. So I think we need to ask ourselves, how has the PJM market been so successful in attracting new investment if that’s the case?

Comment: I wanted to weigh in on this question of contract term, because in PJM the rules of the game are that you've got a commitment three years out that's firm and you can bank on. And when everybody competes on that basis you get a certain amount of costs and bids for new supply. The point here that everybody seems to recognize, is, well, if the term there were longer, so if it were three years or five years or seven years, then there's more certainty on that revenue stream and one would expect a lower cost to capital. So I think that's something that's not controversial.

But something people seem to miss, and when I had done this research, years ago, was to look at the NERC Fan. If people remember that, that you look at the projections that people had made about future electricity needs, and what we observe there is, the longer you go out in time, the larger the expected error. And so we can look at the error in demand and we can say, “Well, if you are short, we observed that when power markets get short, you get price spikes. I can put a value on coming up short. And, conversely, if you're long, I can quantify the value of having excess supply. And of course that cost of error gets larger, the further out you go.”

So the seven years came about by saying, “Well, let's look at the costs of going longer?”—which was the forecast error cost against the benefits of going longer, which was the lower cost to capital for the competitive development that you're trying to encourage. It looked like the balance point there was about seven years.

Respondent 3: I will say again that there was a market that tested this in Texas. There wasn't any PUCT decision or process to say, “Should it be three, five, seven or something else?” The market is doing what developers and retailers agreed to. And it seems to be working. So I think if we assign whatever obligations exist to the retailer—so you need to get energy at all times of day and at the location of your load, and if a state wants to also say you need to buy a certain amount of renewables or carbon-free or however they define the environmental attributes—NRG can make their own judgments and can go out and buy from ENGIE and we can have them agree on whether that's three-, five,- seven- or 10-year contracts.

Respondent 1: One other point, depending on where these forward markets go from time to time for capacity, we see more demand response being contracted for. We're also in the market for that in Texas, so sometimes consumers are willing to sell back to control their bill. So that's an effective mechanism. It's not always about just getting new iron in the ground, necessarily, for instance.

So that'll drive different terms at times, but one of the things about why PJM’s shorter term may be working—when was the last time PJM had a system peak? The load growth has really flattened in the northeast lately. So that's another factor. There are a lot of factors to this.

Respondent 2: I just wanted to reiterate what what was said. The contracts that we're doing, they're bilateral, they’re voluntary, nobody's forcing each other to agree to certain tenor, these are just market rates that buyers and sellers have reached on their own. I'll sayin PJM, oftentimes we see myriad different interest from buyers. It's a smaller pool of buyers that will have a position on capacity and want to actually buy capacity from solar projects. Most of the time, you see buyers just interested in RECs in energy. And then the capacity piece is, for lack of a better term, merchant, and we manage that through the auction process, the BRA and in the interim auctions. And then sometimes we split it with the offtaker. There's all kinds of different structures.

But I'll say one thing about ERCOT and then again about PJM. In ERCOT, the lure there is the ORDC, when you're going to have high demand prices spike in July and August, and if you're a solar generator you're contracted during that period. So you're basically passing that on to whoever your offtaker is that is going to be able to sell that power at the hub during the summer peak hours. But then if something happens, where you might see demand fall off, or maybe the forwards are not as rich as you'd hoped, as we're kind of seeing now because of the drop-off in demand because of COVID, then that really can put a damper quickly.

Because you really only have one product to sell. The RECs aren't worth much. If you're in PJM, you have a little bit more stack revenue, you have your capacity, your energy and then, you can't get ancillary services or a renewable generator, so you don't get paid for that. You can sell RECs, depending on whether or not you're MOPRd. But, essentially there's ways to stack your revenue streams so that, if energy goes down, maybe you're protected a little bit because you have a capacity revenue, if that's not contracted to somebody else.

So anyway, there's a variety of ways, different markets—some of them are better than others in certain respects, but, in some ways, it makes sense to be in both.

Comment: For a long time, the RPSs of, say, the east coast has been able to work alongside a spot market for RECs and you saw in one presentation the volatility of that wreck revenue and pricing over time.

But we're entering into a future where states seem to have adopted, rather than a carbon price, these clean energy standards as sort of their default climate policy for the power sector. And you're getting to a point where a lot of states have said these policies are going to be 100% by year certain. And the sort of modus operandi of those policies' implementation isn't going to be people making investments in clean energy based on spot-market revenue record pricing. It's not going to be a market of many buyers.

All of these policies, certainly in the vertically integrated states, but even in the default utility states, are using the incumbents as buyers and the default is locking people into, sometimes unbundled, but usually bundled power purchase agreements or self-builds that are multi-decadal. So the idea that seven years is too long, maybe it is but it's still a hell of a lot shorter than what we're actually seeming to be led down the path to. I think that's why, now more than ever,it's kind of necessary to think about how to get off that path, because I agree with people who've said that you're you're locking consumers into huge price risk.

And for that matter, when you end up signing these bundled contracts, that might be fine for a corporate buyer, but if you're having the state sign these bundled contracts to eventually drive to 100% clean energy, I think you quickly get to what Bill Hogan is talking about, where people, in their rush to try to tie up the REC value of these long-term contracts, don't quite understand what they're getting or how to price the residual energy or capacity. And when you're a default utility, you don't really have any incentive to care that much about the underlying value of the energy and capacity those projects might bring to the table.

So it's all just to say that I think a lot of people talk about RPSs as this market-based idea, but unless you actually have some kind of underlying real market in terms of how those RECs are being brought to market, that's just not the way the policy works. And I think you're going to see, certainly in the next decade, if we don't do something like a more competitive market for a REC procurement or a perfection of retail competition, you're going to see inevitably that fork in the road people taking that remonopolization of the market. Because it's the only way a lot of these projects end up seemingly being developed in the non-Texas marketplace.

Moderator: I'm going to take the liberty to have the final comment which is I think this is something important. One of the things I'm doing during corona chaos here, sitting in my office here, and you can see at my side are the piles of papers, and one of them is a whole stack of presentations on stranded assets. I'm going to go dust them off, because there's going to be a big market for them. I think that's where we're heading and, boy, I tell you, I'd be making sure my contracts are absolutely airtight, because you can't rely on that future. It just isn't going to happen. Something is going to cause it to unravel.

With that, I want to say thank you very much to the panelists for the excellent presentations. Thank you for the well-behaved participants for dealing with the complications here. I thought this was very interesting. And I'm looking much forward to our next session next week, where I don't have the constraints of the moderator and I can ask for questions. But thank you all.