

**HARVARD ELECTRICITY POLICY GROUP
NINETY-SIXTH PLENARY SESSION****MANDARIN ORIENTAL HOTEL
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TUESDAY AND WEDNESDAY, OCTOBER 1-2, 2019****Rapporteur's Summary*****Session One.****Decline in Revenues: Impact on Generators and Utilities and Options for Response**

*Generators have been experiencing a noticeable decline in wholesale market revenue. The litany is familiar. Low natural gas prices, competition from low to no marginal cost energy sources, increases in the penetration of distributed resources, increased efficiency in the use of energy, imperfection in the markets and in the rules governing them, individual state mandates or subsidies that distort prices, and retail tariffs that do not send appropriate price signals to end users. Policy options include simply respecting marketplace outcomes and the incentives that flow from them, and doing nothing more than maintaining the **current** rules. At the other end of the spectrum are those who see real threats to sufficiency of supply, diversity of supply, and adverse environmental effects, and who contend that more coordinated actions must be taken at Federal and state levels to deal with those issues. Are the low revenue scenarios something other than normal market cycle, or are they part of a permanent market change? Under either scenario, what public policy or regulatory response, if any, should be undertaken? Is there any coherence to the wide variety of policy initiatives? Over the horizon, what are the implications for efficient electricity systems?*

Moderator.

Thank you, Ashley. And thank you to Ashley and Jo-Ann for inviting me to moderate this fantastic panel. So we're going to get things started. There's no question that there's been considerable decline in wholesale market revenues due to a number of changes, many of which were not and could not have been foreseen when the states all restructured, or most of the states restructured. Some of those changes created intended consequences, meaning lower electricity costs and shifting risk from consumers to power producers, and some changes, while

positive, created unintended consequences. Of course I'm referring to lower natural gas prices because of Marcellus Shale, at least to regions that have the infrastructure to bring the gas in.

But I digress. Combine all of that with flat or declining load in many areas because of the investments behind the meter and finally, what I believe is the 800-pound gorilla that is absolutely entering the room, how do markets integrate significant state-sponsored resources? I'm reminded of when I testified at a FERC panel regarding ISO New England's then proposal,

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

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CASPR, competitive auctions with sponsored resources. God, we're an industry that loves those acronyms. When asked by FERC staff what the Massachusetts administration's intentions were regarding the number of long-term PPAs, really the only way I could explain it was simply that when the legislature or the governors say you shall, as a regulator, you execute policy and you do.

And for many states, there is an insatiable and possibly irrational appetite for clean energy green resources, meaning potentially declining benefits. To be sure, this occurs with no thought as to what the impact might be to a competitive market, price formation, and the actual cost to consumers with some subsidies buried deep in the ever complicated customer's electricity bill. On price signals, early on wholesale markets performed admirably just as they were intended to. Incentivizing investment in both transmission and generation but price signals to residential customers, maybe not so much. With some utilities billing systems held together with basically only Duct tape and bubble gum, realistically, because all they needed to do was produce a very simple bill, there will need to be significant investments in software and technology.

The change is definitely coming, especially with states changing utility business models to be much more of a platform to incentivize the adoption of new technologies. Optimistically, even with advancements in techs and technology, I stand here coming from a region that is the poster child of concern every single winter for ISO New England, FERC, and NERC because of the lack of investment in natural gas infrastructure. Our bad winters have been well documented. As I said in a recent op-ed in the *New York Daily News*, the fuel shortage became so dire, ISO New England estimated that the region was only 48 hours from running out

altogether. I won't touch on killing baby seals to get to Russian gas to bring to Boston.

As a self-proclaimed realist and having represented all parties around the energy table, with the exception of the utility, you cannot run the bulk power system on wind, solar, storage, fairy dust, and unicorns. While more acute in New England, this scenario can become challenging in other regions as well. With the economics of nuclear questionable and massive penetration of renewable resources, what market construct will appropriately compensate those resources that are needed to keep the lights on and keep us warm in the winter and balance the intermittent nature of clean energy resources?

As is their custom, HEPG has put together a great panel and it is my privilege to moderate that this morning. We're going to start with Speaker 1, who is the president of the New England Power Generators Association. I'm familiar with that group. Speaker 1 represents generators of all shapes, sizes, and flavors that are all in the forefront of dealing with these challenges in New England as well as other organized, or maybe in some cases unorganized, markets across the country. Next, we will hear from Speaker 2, who works for Exelon who, in addition to being a large utility, is also the largest operator of nuclear generating facilities in the US. Following Speaker 2 will be Speaker 3. Speaker 3 is with Grid Strategies which is a strategic consulting and advocacy firm helping clients with the integration of clean energy into the electric grid and an advocate on grid integration solutions. And then batting cleanup is Speaker 4, who is with the National Association of Utility Consumer Advocates. As I became fond of saying throughout my energy career, there is only one wallet in the room and that's the consumer. So Speaker 4 brings that critical voice to this discussion. And with that, we'll start with Speaker 1.

Speaker 1.

Thank you. And I think with that great tee-off, what I want to do is start with a little bit of context and then transition into where we're going and what's going on here and hopefully then engage with the conversation with you all and the other panelists here.

As the Moderator noted, New England Power Generators is the trade association. IT represents a fuel-diverse fleet in New England. Within our membership, we have approximately 90% of the installed generating capacity coming from every different technology that exists on the grid overall. So to start with some context that I don't think is going to be a surprise to anybody in this room. New England, like most markets in the country, is seeing some of the lowest wholesale electricity prices in their history. In fact, 2016 and 2017 were the two lowest price years ever in New England. In 2018 we saw a bump but in 2019, my guess is we're going to be back close to those 2016 and 2017 levels.

At the same time, we've gone through a period of time in which we're retiring a significant portion of the fleet and adding a significant portion of the fleet, and so some of those low wholesale energy costs have been met with higher capacity prices. And what you see here are the capacity prices within the delivery year. So in 2018 we were seeing the peak of capacity prices coming out of FCA8 and that auction which was the one in which we saw Brayton Point, the second largest power plant in New England, retire. This has helped drive over 4,000 megawatts of new merchant entry into the marketplace overall. And in the context of a roughly 28,000 megawatt peak load, that's a significant portion of the fleet that turns over and is being supported through the competitive market overall.

I have to note that, at the same time, we have seen

an explosion in transmission costs in New England with increases over the last 10 years that have really had a major impact overall and that has then led to consumer impact on the retail level, again as the Moderator highlighted, in which, despite the fact that we are seeing some of the lowest overall wholesale energy prices, both energy and capacity, frankly, we're seeing rate payer rates go up.

And here, this is a busy slide but we broke down three of the major Eversource utilities across New England to try and create as comparable a view across the region as possible and there's really three major components. The red portion is transmission and distribution, the blue in the middle is those wholesale power costs largely coming out of the standard offer service auctions, and then the green portion is what I call public policy and that's things like RGGI compliance, energy efficiency, and RPS compliance.

Overall, you see those blue portions going down and the other portions going up. And this is now starting to become indicative of what we expect to see in a much larger trend moving forward which is those green portions, particularly in places like Massachusetts, Connecticut, and Rhode Island, will become the dominant portion of an overall rate given the large scale contracts that are just now starting to be approved but have not yet gone commercial and therefore there hasn't been the bill impact. But I expect to see a further shift in how we see the retail rates function overall.

And so this brings us to an overall situation in which I'm concerned that we're already starting to see the cracks in the market construct in the region. We have, despite the fact that we have nearly a 30% reserve margin, we've already seen a resource seeking to retire be held for reliability and now an irritative process of new market designs largely driven through the capacity

market now being looked at in the energy and reserves portion of the markets to try and make sure that we're actually valuing the reliability services necessary.

I think that's the key component as we look at this. What are the services that are necessary to ensure the continued reliable operation of the grid, and if we're not valuing that appropriately, let's fix that. If we need to create new products, so be it. I'm concerned that in New England we have not done that. Instead, we chase every previous crisis. And instead, I think we need to take a more holistic approach, a more forward-looking approach of looking at what are the overall requirements on the system as we bring on the new wave of technologies and design around them.

So a year ago, we published an op-ed in *Utility Dive* trying to highlight our frustration with how those conversations were going at the regional level. Following that, we then engaged Joe Cavicchi, who is here, in an analysis of what are some of those impacts and we found that if you take, collectively, just the state laws that were on the books in the fall of 2018, the dramatic shift that would occur in terms of a more merchant-based system to one that is more contract-based. And in fact, this is already now dated where following the legislative session in both 2018 and 2019, if we push this bar out and created one for 2029, the mandated ability of the states to contract would grow to 70% of the overall megawatt hours in the region. That has consequences. And in part, it's as we try and support resource adequacy, will there be revenue adequacy for those resources needed for reliability?

Certainly if we're going to be bringing on a large wave of these new resources, some of the existing fleet is going to have to go away and I think that is just understood in the marketplace overall. But

the question is, how do we ensure that the resources that go away are not the ones that are going to be necessary to support this changing grid and the marketplace overall and how do we ensure that those then left can hopefully be supported through a market-based framework and not moving toward subsidies begetting subsidies begetting subsidies? And what Joe found in his analysis was, I think, two important components.

One is the intuitive side that the flexible resources are going to become more valuable, but these flexible resources are also some of the ones that are going to have large scale capital investments required to maintain their operations over the next several years. And where is that revenue going to come from in an environment in which we continue to see low energy prices and uncertain prospects on the capacity side? The second is a subject that I'm sure others will talk about. How do you support those large scale carbon-free resources, namely the nuclear units, but also some of the in-region hydro that operate on a merchant basis in New England and finding some of the revenue opportunities around that.

My concern is that if we don't try and address these things to, and I apologize to my good friend Jan Smutny-Jones, I worry California becomes our ghost of Christmas future where, if we continue down this path, it will create a marketplace in which unless we have some level of a cost of service or bilateral contract, I don't know how you survive. And it's not too late to try and turn this large ship. We have not yet had that wave of contracted resources calm that portion of the market overall. There is time to design this but we need to get going because those resources will become commercial in likely the next three to five years and given that it takes about three to five years for us to put in place some of the large scale changes that are already in process in the marketplace from a design

standpoint, we need to start and we need to start now. There is some reason for optimism in that we're starting to see the states collectively engage in this in a way that I have never seen in New England.

And so what is here is a block quote from a joint statement issued by the six New England governors, and the Moderator can tell you how rare that is to get them all on the same page. This was largely spurred by a contract approval in Connecticut for the Millstone Nuclear Station, the largest power plant in New England. That contract was granted by Connecticut and on the same day that it was announced, this statement was released of the governors wanting to work collectively in this case, focused in part on nuclear but also to try and drive some of the broader based policies into the market integrated collectively. They then delegated to the New England State Committee on Electricity, NESCO, which are governor appointees to work regionally on some of these issues and they submitted a letter to ISO New England back in July calling for analysis and focus in the 2020 ISO New England work plan to, as they put it here, analyze potential future market frameworks that contemplate and are compatible with the implementation of state energy and environmental laws.

Since we can't help ourselves, we submitted our own letter to support that NESCO call and, again, I'll read briefly. Simply put, the wholesale market as currently designed today, does not provide sufficient revenue opportunities to maintain adequate investments in merchant power supply necessary to maintain reliability in New England in the face of the coming wave of contracted resources.

My hope is that if we have the generator community, these states, working collectively on this issue with the support and engagement of

ISO New England, we can drive the necessary solutions to get our way through this. Whether I like it or not, the states have made their choices and are moving forward with these contracted resources, and it is now our responsibility to find ways in which we can integrate them into the marketplace and ensure that that portion of the fleet that will still rely on competitive market revenue streams will have those services valued in the marketplace.

So what does that mean? In my view, that comes down to two distinct areas that the ISOs start to bleed together. The first is that identification of those reliability services. What is the market going to need over the next five, ten, fifteen years and let's ensure that the products are designed around that. I give the ISO credit. I think that where they've started looking at expansion of reserves, co-optimization of day ahead and real time reserves, bringing some of those into the real time market make a lot of sense and are a great starting point, but I think we need to build out from there.

And what are some of those services, particularly if we're looking at resources that aren't going to be operating as much in the energy market and therefore not as reliant on energy revenues. What is going to be the other revenue stream? That's why we came up with things like capacity markets, to ensure that some of those resources that are only necessary in peak shortage events have a revenue stream and an incentive structure to drive the investments to move forward. The second component of this, I think, is equally important and that's integrating within the markets some of the fundamental policy drivers that are pushing the states in the direction they are in.

And let's be honest, that is carbon. In New England, if you look at just Massachusetts and Connecticut, those two states collectively

represent roughly 80% of the load and 80% of the GDP. They both have mandatory laws on the books to cut carbon emissions on an economy-wide basis, 80% by 2050 off the 1990 baseline. In the short-term, I think the only real way we get there is drastic and dramatic electrification of the transportation and the heating industries. And to get there, we're going to then need to see the megawatt hours go up as we start replacing petroleum molecules and gas molecules used on that end.

To do that, we need market signals. And while an individual carbon price is not a silver bullet that's going to solve all these issues, it's an awfully big chunk of the silver buckshot that we're going to need across these resources and I think it's a critical component. We're starting to see some of the political winds shift on this, in which I'm more optimistic that we're going to see this, in which we integrated both in the wholesale markets as well as in some of those other sectors of the economy that are necessary to move this forward. So with that, I certainly look forward to the presentations of my fellow panelists here and am happy to answer any clarifying questions that folks may have in the near-term.

Moderator: Thanks, Speaker 1.

Speaker 1: Does someone have –

Moderator: Oh, clarifying questions?

Question: On your last point here when you say, you know, meaningfully change the CO₂ prices, are you suggesting just using something like RGGI and just increasing the prices or are you suggesting something more comprehensive than that?

Speaker 1: So I think RGGI makes a tremendous amount of sense to use in existing framework in which we've already got the IT infrastructure and

folks qualified within the auctions; however, I think, realistically, it's unlikely RGGI will be used to provide this more meaningful price on carbon, in large part because the RGGI footprint is so large that, collectively, a number of the states don't have as aggressive some of the climate mandates that exist for some of the dominant states in New England. So my guess is it's going to happen outside of RGGI, although I would love to have RGGI be the vehicle that drives it.

Questioner: And I did have one other clarification question. On page five you have the three categories of the retail rate and one is green, one is red and blue or something like that, and then I think you made this comment that the green was going to get much larger and be the dominant, I think you said. A question for you, is the green calculated as the total cost of these state mandated resources or is it just kind of the line item or the writer kind of subsidy portion of it? Can you explain what I'm trying to get at?

Speaker 1: Yes, so it is the former. It's the overall cost of the component and, I'll admit, we had to make certain rough justice assessments as part of breaking it down on an even basis between the rates across the states. So it is, there are certainly some nits that can be picked in how we categorize what's in green versus blue and the rest of it, but collectively, the expectation is as that green portion starts going up, the blue portion starts going down because we start relying on the standard offer service auctions for less load and, overall, the green portion then, both because of the scale of the amount of power being contracted as well as the cost of it, becomes the largest single portion of this three-part breakdown.

Moderator: Another question?

Question: Yeah. And Speaker 1, I just want to follow-up. So the green, is that existing or new?

So that would include hydro coming in? What's in there?

Speaker 1: So that is only existing. IT does not include even the hydro contracts which have already been approved given that that rate impact doesn't occur until that resource becomes deliverable.

Questioner: HQ power, is that considerable renewable or that wouldn't fall in there?

Speaker 1: So it's, it doesn't meet the renewable mandates in any state in New England except for Vermont, but similarly, it would be included in the green as, what I call, a public policy component but is not reflected in this chart today.

Moderator: Another question.

Question: I just wanted to make two comments. One of which is, we at ISO New England have very publicly supported a carbon price. I think we are starting to come to the same place that we came to on gas pipelines which is, it's not going to happen. The New England states have been so vociferously opposed to a carbon price that, I think, while we agree to elegant, simple, easily implemented solutions and the answer to our prayers, it's just, we have to move on, we just don't see it happening. So I think it's time to start looking at some other options and, you know, with deference to the FERC folks in the room, I won't say much about this except that we are working really hard at trying to identify those characteristics that we need to ensure the reliability of the grid while we have this influx starting.

And finally, there's no doubt that the state governments are having an impact on the blue portion but I do just want to point at that where you showed the capacity revenues increasing, that is the markets working to some degree and

they're working hard in the face of a number of sort of countervailing factors but the capacity price is increasing where needed to provide that missing money that is being lost in the energy markets. I just wanted to say a word in our defense.

Moderator: Anybody else?

Speaker 2.

Hey, good morning. So I'm with Exelon, as mentioned, the largest owner of nuclear power in the US. We're also a very large utility with customers from DC up to Atlantic City over to the Delmarva Peninsula and then the northern Illinois, Chicagoland area. So we think about this kind of question of price impacts, changing generation fleet, environmental goals from multiple angles. From, obviously, the owner of the largest source of emissions for generation from preserving the value and the operation and preventing the loss of those units and the environmental impact but also from the customer perspective of what's the impact of taking action and of not taking action, both from the electricity price perspective and environmental perspective in terms of climate impact.

So when I read the agenda, I kind of feel like we're asking if not the wrong question, then not the entire question by focusing on low prices. You know, for me, the question really is, what are we trying to solve through the markets? What are we using these tools for? And the agenda tees up three issues: sufficiency of supply, diversity of supply, and environmental impacts. The sufficiency of supply, and I think it's taken care of through RA requirements, resource adequacy requirements, different structures and the various RTOs and regional markets. You can debate about the relative merits of each of those, economic efficiency and, say, SPP versus a New England model, but the mechanics are there to achieve resource adequacy. On the diversity of

supply, that's an emerging issue. Some RTOs are digging into this more than others.

Exelon folks believe this is really important but I'm not going to focus on this area, in particular because there are some pending matters at FERC which actually make this whole conversation kind of difficult and several of us will be trying to keep issues up at a high level so we're not making the FERC folks leave the room. But I'm going to focus on that third piece of what the markets are trying to achieve or what the markets maybe used to achieve that's flagged on the environmental impact. So, in my mind, low prices should not be driving the policy response. The policy response should be, what is it we are trying to achieve and if prices are high, they're high and if prices are low, they're low, they will drive particular outcomes in response.

Because I'm kind of drilling in on the environmental piece, I want to kind of center us in the science. So these are graphics and information pulled from the fourth annual National Climate Assessment which was released in November. If you recall, this was the cross-agency or cross-governmental report that was released on Black Friday by the Trump administration which, on the right side, it shows the economic damage at the end of century of essentially business as usual practices.

So the left side is kind of how we get there; emissions, trajectories, and the kind of top line, there are some areas that are kind of wonky; RCP8.5, is essentially kind of business as usual scenarios with growth of emissions and the middle scenario, the blueish with the decline is essentially kind of an 80 x 50 reduction trajectory, and then the green on the bottom is kind of true immediate deep decarbonization through extremely aggressive policies. The temperature impact of those emissions trajectories you'll see in the bottom left and essentially takes you to

about 4° C for business as usual policies, that's 8° F; 2° C for the 80 x 50 target, that's 4° F; and 1° C with the very aggressive, 2° F. I note that observed emissions and temperature increases we've kind of already, we're on a path to blow by the green line, so that's not really an option for us now.

And so the choice is where are we going to be, you know, kind of in between a 2° C and a 4° C which takes us to the right side of, well there's a cost of not achieving the emissions reductions. And the gray bar in the middle, that is the, again this is Trump administration cross-governmental panel estimating out at end of century if we are on the path to an 8° F temperature rise, average temperature rise, then the economic damages in end of century are going to be those add up to about \$1.1 trillion a year. If you avoid that by maintaining to 2° C, that's the right chart, and rough swing is about 50% when you add up all the individual line items so that's a \$500 billion economic impact associated with meeting our emissions reductions. And so when we think about environmental externalities and what we're doing in the electricity markets and are prices reflective of the costs that we are incurring associated with running generation, here's one swing at what the impact of not achieving our reductions means.

So that's a \$500 billion per year difference in the emissions impact. So that's why states are taking action on decarbonization policy. There's discussion at the federal level but we'll see what happens with that. When you look across most of the studies, there's general agreement that you need decarbonization in multiple sectors or pillars of decarbonization as already mentioned, significant electrification, increase in efficiency to manage that increased load growth which was already mentioned that comes out of electrification, and then decarbonizing the generation stack so that the increased

electrification is not being backfilled with emitting generation.

The decarbonization of the generation sector serves two functions. One is removing the carbon from the generation stack which is needed to meet our emissions goals but then the second is to not replace the switch to electricity as you're moving away from carbon-intense resources for other uses like transportation and buildings and all of that, replacing it with some emitting generation. So, we all know the policies kind of active and that have been used in the generation decarbonization space, CES, RPS, PTCs, ITCs, carbon pricing, already mentioned carbon pricing, yes, it's the way to go.

I totally agree with the comment from ISO New England, we're kind of not holding our breath. And we are founding members of the Climate Leadership Council. We are pushing this issue at the federal level, at the state level. We would love to see carbon pricing, we'd love to see leakage control in PJM but the reality is the states are moving forward with mandates, RPS and CES mandates. And so that's kind of the question for us of do we all agree? Do we think that we're going to continue to have a collection of state mandates through things that look like CESs and RPSs and procurements. And that's kind of where I think I am. I think that's what I heard Speaker 1 say.

Then we need to think about how our wholesale electricity markets, whether they be in the RTO or bilateral, are organized around that set of policies which are not really going to change. So you could argue RPSs, some version of standards have been around for 20 years. Right? RPSs were kind of developed in the late '90s, kind of took off in the 2000s. That's right around when the RTO markets, the organized markets were also taking off. What changed? We had almost two decades of market enhancements happening

in parallel to the growth of essentially renewable generation under this collection of policies. Why are we worried about it now?

Well, Speaker 1 touched on a lot of this stuff and I just pulled some graphics from New England to kind of talk through. So he already covered the growth in the state-sponsored revenues going to state-sponsored resources as opposed to resources solely relying on the competitive markets. And I thought it was interesting that that's growing. Right? The current number is up to 70%. So on the right is another set of data coming out of that report of the declines in the combined cycle ability to essentially earn revenues in the market as a result of this increasing amount of zero or low marginal cost resources coming online.

And there are various scenarios that depend on whether there's cycling on and off overnight and whether it's colder in here. So the point isn't to debate the accuracy of these individual estimates but it's just that you can see that there's up to a 40% decline in revenues for combined cycle units. So then, okay that's today or kind of over the planning horizon of what we know is coming on and we can put our fingers on. Well what about the future?

Brattle just released a report, I think it was last week, if not, in the past couple of weeks, looking out to the future and saying, okay well what does the collection of New England states, what do they need to achieve their decarbonization goals? And as it was just mentioned, two of the largest load states have adopted 80 x 50 goals, so they are going to achieve significant amounts of electrification like we just discussed. They'll be ramping up their efficiency as much as they can but they're going to need to decarbonize the generation stack serving a greater amount of load over time. And so Brattle estimates that that's going to be as much as 5,000 megawatts of

incremental add of clean generation which solar and offshore wind is kind of their two biggest chunks of how they kind of swing that. So again, you can debate the numbers and whether that's headed up at the right kind of trajectory but it's undeniable that there's going to be a huge amount of largely renewable generation that's coming online as a result of state policies. So then you can kind of look to, and so I think the question there is the New England market, as Speaker 1 teased out, like, is the market going to achieve that outcome? You can look to California and similar examples out there.

On the top left it's the frequency of near or below zero day ahead energy prices at or below zero, and you can see kind of right around 1-4 o'clock, you're getting up to 10% of hours in California having effectively no revenues coming out of the energy market, so that's obviously impacting. They've run some numbers. These are from the DMM 2018 market report. They've run some numbers on what is the revenue adequacy of the combined cycle units? How much are they earning from the market? And it's a significant kind of under-recovery of fixed costs under the DMM analysis. So, then, what about the future in California? So E3, which has done a lot of modeling for the CEC out in California has looked at long-run resource adequacy under the buildout. What is going to be needed in California in order to meet their resource adequacy requirements?

And again, you see huge buildouts of largely solar with a bunch of storage under their modeling. And again, you can slice and dice these numbers in different ways and have different collections of resources, but the take-away is that there is a huge amount of investment that is going to be needed to meet the decarbonization goals. And where is that money coming from? So that takes us to the market design questions. Right? As I think about this, there's the almost realignment of

responsibilities that states clearly have a role in defining the generation mix. And it's not clear to me how you separate the generation mix question from the revenue sufficiency question as to how to support that generation.

On the other hand, the regional energy and ancillary service markets have undeniable value. Right? And so regional commitment and dispatch achieves sufficiency results in significant consumer cost savings, and it's not clear to me how you separate the operational requirements from that set of regional commitment and dispatch decisions. So that includes things like ramping reserves, all of that. So what does that tell us in terms of what we need to do in these markets?

Unfortunately I don't really have all of the answers but I think that in regions with capacity markets, there's a very open question whether they will be able to achieve currently a structure, they certainly cannot achieve the goals that are being established by the states. And so the question is, what do you do with those? Does the resource adequacy question in the capacity market regions remain at the RTO level or is there kind of a return to, of responsibility to the state? And this gets very close to PJM and New York matters, so I'll just kind of leave it at that. But it's a very, very open question at FERC in terms of the design of the markets and at the states in terms of how they are going to achieve these kind of aggressive investment responsibilities which are looming.

So on the left I say states are going to need to have a significant kind of responsibility over the generation mix. I did say states intentionally. It doesn't necessarily mean that each state is acting on its own. So for example, in New England, there have been regional procurements of clean energy resources. There can be ways to think about optimizing the decisions that aren't through

an RTO mechanism.

Now will they be as efficient or not? I think you can debate that either way but given the realities, just the practical realities of asking states to cede these decisions to an RTO subject to exclusive FERC jurisdiction, I'm a cynic on that. I don't see it happening. So then I think, okay, well then let's improve the existing energy and ancillary services markets to the extent possible. Let's focus on reserved product definition, get pricing better in the energy markets, have products aligned with the flexibility needs, and then leave the generation mix questions to the states. That does take us to kind of the bottom of this issue of when the state's selection doesn't lead, even collectively, to the reliability requirements that need to be met by the RTO. These do loop right back to the conversation that started the capacity markets years ago of RMR agreements leading to the need for a centralized capacity procurement.

But I challenge us to think through that issue differently now because I just, I'm not convinced that the centralized capacity markets, as we know them now, can really answer the investment question, the clean energy investment question that we've got. And so we need to think through a way to maybe lean on the states a little bit more heavily on this, this backstop procurement issue, whether that's local reliability or resource adequacy. So, again, I don't really have all the answers. Hopefully we are all teeing up the questions and we can have a good debate.

Moderator: Thank you. Any clarifying questions?

Question: I think this may be borderline but I'm going to go for it. Speaker 2, so if centralized RTO capacity markets don't work, are you suggesting that when the states do their capacity procurement and resources, that basically that should be done essentially going back to a rate-

based approach?

Speaker 2: I don't think it has to be. I think states could make that choice but there are other mechanisms that states could use to, I mean, this is hard to answer the question fully without getting into matters that are specifically pending at FERC. But I think it doesn't, it doesn't have to be. Right? Take the New England clean energy procurements. There are ways to engage in bilateral contracting on a more coordinated basis that still rely on competitive markets. RTOs aren't the only competitive markets out there. Bilateral markets are competitive. So it just depends on the breadth and structure of what those kind of procurement frameworks are, how they are designed.

Moderator: Any other clarifying questions? All right.

Speaker 3.

Thank you. The Moderator mentioned who we are but if you don't know, I've worked in and around renewables for about 15 years so that's the kind of large focus. Our mission at Grid Strategies is really low cost decarbonization. So we do work for wind/solar storage as well as consumer interests occasionally. I told Bill I was going to attempt a two-fer here today. We have a morning panel on what to do about low prices and we have an afternoon panel on what are the lessons from California, and I'm going to try to have a single answer to both questions.

I'll give you a little heads up, the answer is we need real buyers of power and they need to be creditworthy and capable of doing their job. Now to build up to that, just to mention, what I'm talking about today is really based on a couple of papers. The one on the left was for the Wind Solar Alliance about power market design for a decarbonized future and the one on the right Mike Hogan and I did recently and that was part of an

energy innovation series. Now first to get one issue hopefully out of the way in terms of what's causing low prices and the reason for this panel, one often hears and the blurb for this panel mentions not only the issues but let's be clear, low natural gas prices are far and away the biggest driver. So for everybody who is suffering from low power prices out in the market, I think we can all feel sympathy and who saw that coming? If we had, we'd be rich and all that.

But this is a slide from Lawrence Berkeley National Lab. The beige line is the natural gas price, the blue band is the power price and you can just see how closely they track. Natural gas prices set the power prices in most wholesale markets, so there's just such a strong tie between what the gas price is and what the wholesale power price is that that's really the reason for the low prices that we're seeing. In the context of the whole kind of resilience coal bailout, whatever you want to call it from the Department of Energy, Lawrence Berkeley Lab did some work for DOE trying to figure out what are the causes of the low prices.

And there, again, you can see that the left bar that, between 2008 and 2017, what's the cause of the drop in prices? That big green bar is natural gas price. So there again you can just see the order of magnitude here. Natural gas prices are really the reason we're seeing low power prices. So I think we should be clear on that context. Now as a renewable person, you might say, 'Oh, but you're trying to hide the effect of renewables,' and I'm going to get to that. At current levels of penetration, we see, this is University of Texas Austin, showing the right supply curve of the supply stack shows that green, low, that's the zero marginal cost effect there.

So at most levels of demand, there's almost a trivial impact on price. You can see that you add that if big slug of low cost renewables on the left

part of the supply curve, it almost affects price not at all. So that's a way of saying that I think at current levels of penetration, we're not seeing this big monster called the zero marginal cost problem that's wrecking our markets.

But now let's talk about the long-term future. Lawrence Berkeley Lab also did a report on high renewable penetration, so they were looking at 40% penetration, much higher than we have today. They did this for four or five regions. You see the familiar shape, this is the changing load shape, the duck curve. The current red line, that's current prices, what prices look like over the hours of the day. The three bars below that in different colors are the portfolios. You can maybe just focus on the blue, which is high, which is sort of balanced wind and solar or 30% wind and 10% solar. Obviously the yellow line with high solar gets more of the duck curve shape. But you can see you do have low prices in the middle of the day.

So, yes, we are getting to a future where we're going to have lower prices at certain times. And so the question that I think a lot of people are asking is, 10 years out, what market structure are we driving towards? Not to hit you with too much business, if you just focus on where the arrows are pointing here, these are the average annual price decreases and the green one is the balance. So there's a 21% average drop in wholesale price in SPP, New York gets high 30s, 23 in California, 17 in ERCOT. So, you know, 20-25% is typical if we really ramp up wind and solar, yes we're going to have somewhat lower average wholesale prices, you know, it's not dramatic, it's not zero all the time but 20% is meaningful. If you go to the third from the bottom band and you look at price variability, that goes up.

You can see in some of these charts, like, let's look at the ERCOT one on the far right, there are

times of day where prices do get very high. And so I think you can say, well if we had sort of a pure market, we're going to have somewhat more variability and we're going to have higher prices at certain times and lower prices at other times. But here, again, we're talking 10, 15, 20 years out. Does this mean we need a revolution in our market structure and design or is the basic kind of structure and design that we've been talking about for 20 years at HEPG and 20 years at FERC, is that robust to this future with all these zero marginal cost resources?

So I am going to take the position that our basic market structure and design that we originally talked about and most people here were a part of it is robust and can handle this change. I'll acknowledge as the Moderator noted at the outset, that we do have an economic question of how do we deal with market structure and design with zero marginal cost resources noting that energy and other services are needed at times and places that renewables alone won't provide, which is a point I think we can acknowledge that's true. Now whether that's demand response and long term storage or gas or whatever other resources to fill in the gaps, we can all argue about that but we do have the sort of economic question. How do you make sure one can invest in this market and provide all of those resources, not just the clean, but all the resources you need for reliability?

There are some other technical questions that are also very interesting. I think solvable but challenging is whether physical balancing can be achieved with the highly variable supply mix and then frequency support when you lose the inertia from synchronous unit retirements. I would highly recommend going to the Energy Systems Integration meetings on those. There's a lot of vibrant discussion there. But I'm going to focus more on the top one which is the investment question. Just a note on reliability, don't assume

that renewables don't contribute to the reliability.

This is the famous ISO New England Fuel Security, Energy Security and Resilience study, Operational Fuel Security something or other, Analysis, OFSA, I missed that acronym, I lose a point. But if you look, four of the five or six most reliable scenarios are high renewable scenarios. So you can look at the report and see how that happens, but you just don't assume that renewables are just there providing clean energy. They're also contributing to reliability.

Let's talk about this long-term future. I think there are some well-accepted physical system requirements if we are going to do high renewables, and maybe from here on out let's stipulate with wind and solar being as cheap as they are, let's talk about a high renewable scenario and what's its system look like. So first of all you need very fast dispatch; fast, far, and full. I tried to summarize it. Far means you need large regional balancing areas. RTOs do that but if the wind is not blowing here, it's blowing somewhere else and the wind balance system will work solar so you even get some time of day balancing of solar in different time zones. So with all these things plus just the variability, you can get a lot more for low cost if you balance it across a very wide area. So we do need large regional markets.

And I think as Speaker 1 said, we need to define the reliability services and procure each of the services you need. I would start with the NERC-defined central reliability services. You can Google that, look it up. They pretty much define what those services are. The exact quantities do vary by region. ERCOT is more of an island and needs more frequency support, etcetera. So the numbers are different but the services are essentially the same. So let's start with, we should always do, I think, structure before design. Let's talk about who should do what and Speaker

2 got into this.

First of all, certainly environmental externalities need to be internalized. There are a lot of ways to do that. There are first-best, second-best and 20th-best ways to do that and we can argue about that. That's a second, separate conversation. The RTO/ISO, the grid operator, so I'm taking the position here about, you know, one way to do all of this that I think is feasible economically and physically. You go back to what FERC originally said in Order 888 ISO Principles and Order 2000 Characteristics and Functions for RTOs and it was basically kind of the neutral air traffic controller focusing on the real time operation of the grid. So that's their job. They don't care about price. They're just, they don't care, you know, they're not the air traffic controller trying to tell Southwest Airlines how to run their business. They're just the neutral operator. Retail suppliers competitively procure power, or hedge for this sophisticated audience, with long-term contracts, PPAs to serve their load.

As Speaker 2 said, bilaterals are not a dirty word in this, in this vision. They are critical to financing new generation and for managing price risk for consumers. Now here, I highlighted some missing pieces. At this top, we're not really internalizing externalities yet but this is, I think, an important conversation. For states for those retail suppliers to really serve their customers, they need to make sure that retail suppliers are actually credit worthy buyers of wholesale power. Now the PUC of Texas does oversee, as Travis and others have pointed out to me, the credit worthiness of the buyers in Texas. I don't think they do enough, but we have to avoid the risk which I think a lot of states that went to retail competition forgot about which is; some retail supplier opens up a business in their garage, they serve a bunch of customers, prices get high, they say I'm out, they go bankrupt, their customers are left in the lurch, there's a public good market

failure and nobody precured their long-term contracts to bring in the resources needed to serve that load.

That's a problem and I think that's a job for states. That's not an RTO credit issue, that's a state licensing issue. If you want to do business in our state, you've got to make sure you're capable of serving load in the state. In this vision, utilities are largely wires companies. They are, you know, transmission and distribution are still natural monopolies, that hasn't changed, but generation was declared competitive 30-some-odd years ago. It's even more competitive today with the small scale of generation, small size of competitive generation, so that should be competitive everywhere. Independent power producers provide all that generation. They bid for those competitive procurements. Again, it's a competitive sector. We can rely on them to compete and provide consumers with good value.

And then there are financial participants allowed to provide risk management products, and I'll get to that in a minute and how that fits in the whole picture. Now everybody here will recognize this picture. I'm not just sucking up to Bill here, well there's some of that. But we've known what the core workable market design has been. So we did market structure before, now this is market design. It relies on a bid-based security constrained economic dispatch with nodal prices, financial transmission rights. There are bilateral schedules up at the top. This was sort of what FERC decided and most of the RTOs decided in the mid-'90s and what we've been doing and this part of it is working very well.

It also, I should note, provides a large regional operation for the high renewable future, so that market design is very much the friend of clean energy. Now some other pieces of this, again, there is an active bilateral market that works in concert with the spot market. These PPAs are

priced, not at marginal cost, nobody is signing wind or solar PPAs at zero, you sign it at essentially the average cost over the long-term for those units. You do always have the spot market for residuals. Everybody winds up longer or shorter on any given day. Hourly locational pricing. Reliability services and this gets to Speaker 1's point to find the reliability services and competitively procure them. The exact needs will vary somewhat by region but the services, frequency, support and different types of operating reserves are essentially the same. Now scarcity pricing, I think we have the advantage now. We've got some years of testing and this has now been proven out. This is an important part of a workable market.

Operating reserve demand curve scarcity pricing, the value of the energy at the time and place you need it will be an important thing. And the most important thing about this is that we're all failing in determining when exactly those scarcity conditions are going to happen. MISO is finding them at shoulder periods in the spring and fall, in the northeast it's polar vortex, sometimes it's winter. All the planning models are based on summer peaking but that's not actually when many of the conditions happen. So the point of scarcity pricing is we can't predict. We don't know when exactly they're going to happen but we're equipped with the right pricing to attract the flexibility and power when we need it.

I'm going to skip the last point for the audience here. The main point, getting back to the structure, is RTOs are in the business of short-term operation and so you don't get into half the debates we're having about capacity market design in this. Now is this working? Well, every year we seem to look at ERCOT and say, oh this is the big year, we're going to test it in ERCOT and we've had another test. I don't know how many years or decades we have to keep doing this but, okay, let's look at this other test. So this year,

this is just our own numbers we've put together the price duration curve. These are prices over \$200 and quite a lot of times, it looks like 25 hours the prices got over \$1,000 in Texas and with an eightish percent reserve margin, you would expect some high prices from a consumer perspective. You have to compare this to the capacity market. And would you rather pay this for a few hours and also knowing that almost everybody is fully hedged, so almost nobody actually paid this but you did have some high prices in Texas.

Now is this getting to revenue adequacy? Well, I think people are going to start writing the postmortems. We just did our own. So if you look, now the Potomac Economics chart is for a combined cycle and you can see prices are well below the blue band in recent years so generators are not recovering their investment costs. You could say, well that's gas prices and it's unfortunate but that's the market. But let's look at Texas. Now we're going to shift to peakers, if the peaker net CONE is one hundredish dollars a kilowatt year. In 2019, year-to-date, they have earned \$123 a kilowatt year and they're on track, if the rest of 2019 is like 2018, they're going to wind up at \$137. So they're going to be well above what they would need to attract and retain investments. So I would say early signs are good for Texas finally working. They do now have scarcity pricing and operating which are demand curved so this is a model that seems to be workable that we can use.

Now a couple of comments before I wrap up here, just on how things are going in ERCOT. This is, folks here know Julien Dumoulin-Smith. There has been a rally in power pricing so maybe this whole era of low prices is over, at least when you get the right market design and supply and demand in a different place than we have in the northeast anyway. So they are perceiving, from an investment perspective, that there's an

opportunity to invest there. Now let's also be clear, you don't invest in 40-year assets on five-minute prices. I'm not claiming that you do.

So I hate the whole phrase, energy-only market, because it's not an energy-only market. There are physical bilaterals, synthetic PPAs, all kinds of long-term arrangements that are serving to finance the new generation, again if, and only if, you actually have creditworthy buyers who will sign those contracts. Those can be utilities or other entities, but you do have to avoid the free rider problem which they have largely avoided in Texas. This is from an actual investor prospectus, someone going around and trying to finance a wind farm in Texas. They have a 12-year hedge arrangement. ERCOT has no visibility into this nor do they need it, it's not their job, but these long-term contracts do exist. People are investing based on these private bilateral contracts.

You can also do a basis hedge and hedge other risks if you want for congestion. Texas industrial consumers recognize this as what's going on and say bilateral hedging activity and premium forward pricing provides a considerable revenue stream for generators beyond the ORDC. This is an efficient market solution so I think consumers there are recognizing, you know, again this model can work. This is going to be a long story but I think I'm out of time. Just the idea that I mentioned first-best, second-best public policies, you can have, this is Michael Goggins' home and he put up the solar panels on the right and then based on the incentives, his neighbor pointed his straight up in the sky and was not getting any sun. So we'll just acknowledge from a renewable perspective that not all policies are first-best. [LAUGHTER]

Moderator: Clarifying questions? Yes?

Question: Speaker 3, I think it was slide 11 when you were talking about the structure—

Speaker 3: Let's see if I can still get that.

Questioner: On the bullet for retail suppliers, can you clarify more if there's a difference between competitively hedging and PPAs? And then when you say PPAs, do you have a sense of how much time or length there is in that PPA?

Speaker 3: Well, so some form of long-term contract is needed to finance new wind solar storage, whatever resource, whether that's five plus years, seven plus years, I hear things in those, in those ranges. Obviously everybody would prefer a 25-year contract, every generator would. As to whether it's competitively procured or otherwise procured, I mean, certainly you can finance with rate-based, you can finance in other ways. I would say from a consumer perspective, there should be competitive procurement from independent providers unaffiliated with whoever is doing the procuring and that's the way to minimize the cost of it.

Questioner: Just one other quick follow-up. Have you looked into the misalignment between those terms and the average retail contract being somewhere below 24 months? So you've got retailers who, on average, sign contracts for less than 24 months across all sectors and then you're mentioning years that are five, seven, twenty-five?

Speaker 3: That's right. So, and again, the ERCOT model is one way to do it and you do always have this issue with retail access, that consumers can move and if you're a retail provider, you have that challenge that your consumers could leave and then why would you sign a contract for a multi-year PPA, and you're right to raise that issue. In Texas it seems to be working where there are private market participants who will go out and sign that contract. So Goldman or, I don't know, Heart

Tree or one of these other entities or just marketers will sign those contracts. And they are, and that's how people are financing new generation there.

Question: I have a quick clarifying question I think. So in your model the utilities are just T&D entities and there are retail suppliers that procure power to serve a load, but then at the end you said one of the potential counterparties for a long-term PPA would be the utilities. Why would they sign it?

Speaker 3: Well, I guess you're right, the pure version of this would be that you don't have the utilities doing the procurement and you just have the utilities as wire companies. I mean, I was sort of thinking about Texas and ERCOT. They do have a combination, they do have some cities that buy power, they have munis so that is one way to do it if you're just focused on the financing problem, having those entities do it.

But you can do it with full retail choice if a state so chooses. A state could also choose, and this is probably what I would do if I were a state regulator, I might say, well residential customers like myself hate getting stuff in the mail and we don't always want to choose so maybe a certain set of the mass market has some type of planning. Maybe it's a New Jersey style PGS where there's an auction for a large group of them. There are other ways to do it, other forms of group buying for consumers maybe who don't want to choose. That's an option but, again, you could do the full retail model and you can finance generation with that model.

Moderator: Other questions?

Question: Yes. I think this is a clarifying question of the same slide. Reflecting on taxes or more generally on a best market structure for low cost decarbonization, I was wondering if you

could clarify more what you had in mind in terms of how decisions would be made for what transmission is built to support new renewable generation and how the costs of that new transmission would be paid by different consumer groups?

Speaker 3: That's a great question, maybe for another day but since I mentioned here, the RTO is also a natural entity to do regional planning because, again, you don't need two different sets of lines and you can find reliability improvements and efficiencies if you have the RTO also do that as well as the balancing. I would say from a consumer perspective as well as a renewable perspective, that they should essentially be doing more proactive economic planning in addition to just reliability planning and if you have, vast areas of low cost renewables, the planning should take that into account.

My favorite types of plans are those about the future, and that seems to be the future and that seems to be what consumers want. And so our transmission planning, I think, should be proactive efficiency as well as reliability based. And then how do you spread the costs, In the FERC jurisdictional area it's roughly commensurate with the beneficiaries. I think that regulatory principle can work. It doesn't mean it's easy. FERC will, at the end of the day, have to sort out who pays how much but the principle is workable and has been implemented.

Moderator: Other questions?

Question: Yeah, I just wanted to follow up on the question about transmission planning and the other point here. There's a lot of behind the scenes handwaving where we say, "Oh well, that's just a job for the RTO," and if you actually knew what ERCOT is having to do or what New England did to build new transmission into Connecticut and it's all in the assumptions. If you

look at ERCOT, their reliability planning for transmission building is to assume, is to run a market six years out and they don't have enough generation to meet load so they just scale everything up and down and then they have certain criteria that figures out, what, it's not based on where the wind is built and it's just an opportunity for people who understand the rules to figure out behind the scenes rent seeking to get certain transmission built which is not necessarily optimal.

And I think we have to be very careful to grow all this onto RTOs and say, "Oh well, they'll figure out the transmission solution." But because, in fact, what you have is generation and transmission actually competing with each other and having the locational element. So if New England decides to assume that there's going to be no gas generation located inside Connecticut, it's very easy then to socialize two billion dollars of transmission to me and other New England consumers based on a reliability need where if they made different assumptions, they wouldn't.

Speaker 3: I totally agree. It is a regulated natural monopoly and the regulators and all of us participants in the regulatory process need to be involved in that. And they have tough choices and they need to make regulatory decisions. They could invest here or they could invest there and to assume that there's going to be no increase in renewables or electric vehicles or other things that are going to change the use of the system would certainly be wrong. And it's not obvious what is the right answer in terms of those assumptions but they have to be made.

And so somebody has got to make sure those decisions get made and we do good plans. Again, to me, we should plan for the future. And we might disagree somewhat on where the future is going but if you look at Speaker 2's charts, we don't disagree, there's some imperative and states

are being pretty clear about the resources they want. So the Order 1000 rule about, oh consider state policy, so you have one meeting and, yeah, we thought about it and then you move on. That doesn't work. We're going to have to review public policy and incorporate that into planning.

Moderator: Go ahead.

Question: Sorry but my transmission colleague has left the room and I suspect I should ask this on her behalf. Are you saying, first of all it's interesting we're talking about transmission because Texas is so different from the other RTOs. Right? In the other RTOs it's the generators that have the deliverability requirements and Texas, we build, you'll come. So if you could clarify in terms of some of the statements you've made, how you view those different models and what you've said? And two is, I'm hoping that you will clarify that you really didn't mean transmission is a truly regulated natural monopoly. So maybe you can clarify what you meant by that.

Speaker 3: Well, I think it is a regulated natural monopoly. Now I can tell you're getting at the competitive bidding aspect of that and, look, one way to regulate natural monopolies is to require competitive bidding for the right to own that asset. So I'm not going to get into that debate any further now. We're already pretty far off topic. But it still is a regulated natural monopoly. Now your first question, yes it makes a big difference whether the job of paying for a new transmission is on the generator versus sort of on load, that's certainly important. I would say, just from a consumer perspective, the main thing is to make sure we're proactively planning for the expected future resource mix and then we assign costs in a fair way across all resources. Does that mean it's 100% generation versus 100% load? Probably not. There's probably some combination there but that's probably a panel for another day.

Moderator: I guess I'll do the moderator's prerogative for just a second because we're running low on time and I think the consumer voice is so critical to this panel. But just an observation, I guess as a regulator that sat on siting commission, I think the contrast with ERCOT is really interesting and Texas is certainly probably the most different place there could be from Massachusetts to New England since you can't site a hamster wheel in Massachusetts and that includes transmission to bring in green energy and all of that. That's the first observation.

And the second one is uncapping electricity markets. And I believe Professor Hogan, way back, I asked you a question about, and I fielded questions in 2015 when the capacity prices went nuts and they basically wanted ISO and Gordon's head on a stick. We were fielding questions from every congressional office because they were so angry about high capacity prices. I can imagine if they uncapped the energy prices in New England. I think it would be politically, shall I say, unpalatable or challenging. But that's just an observation with my experience but this is interesting. And I want to turn now to Speaker 4 to talk about the consumer's voice.

Speaker 4.

Well thank you. I don't know if everybody in this room is familiar with NASUCA, the National Association of State Utility Consumer Advocates. So we are the state level statutory advocates involved in the rate making process. I always have to start off with my standard disclaimer. I have 58 members in 43 states, DC, Virgin Islands, Barbados, and Puerto Rico. I can't often speak with one voice. I can't give you a specific answer to anything. I have a lot of different constituents with a lot of different opinions operating in a lot of different market structures with a lot of different answers and a lot

of different political constraints.

So with that, I do my best. But I do have a message, I think, from the consumers and that is this. Low prices are not a problem we need you to fix. [LAUGHTER] Okay, let me say that again in case anybody missed the subtlety and nuance in that statement. Low prices are not a problem we need you to fix for us. Okay? Now what I thought I would do with my little piece of time because I don't have a PowerPoint slide and I'm not deeply involved in all of the markets to give you data, what I thought I would do is give you a short, abridged, slightly tongue-in-cheek history of restructuring according to consumer advocates.

And it goes something like this. Bill Hogan came forth and said, I have an idea, we can do things different, generators are not necessarily natural monopolies, we can break them apart, we can create markets, we can get efficiency, we can do amazing things, and we will get low prices for consumers. And about a third of the states said, yeah let's do that; a third of the states said, no I don't think so; and then there's the west, and I'm not even here to talk about the west. Jan's here to talk about the west, so I'm not even talking about the west. So in the third of the states that said, yeah let's do that, we said, first we've got to separate the generators from the transmission-owning, still natural monopolies. But there was a problem. Prices were going to be so low that those poor utilities and those generators were going to lose a lot of money. So they came to consumers and said, look, if you just pay a little bit of money, then you can get low prices out of these markets.

And so we created stranded cost recovery funds. Billions of dollars were charged to consumers so that we could go forth, operate in these markets, and get low prices. What a deal. Fast forward slightly a little bit, the markets are up, they're

running and natural gas goes to \$13 in MMBtu, natural gas set the marginal cost on the market for every kilowatt hour sold in that market, and those lucky people that owned coal plants and nuclear plants made money hand over fist. It was amazing. It was a massive transfer of wealth from consumers to the utilities that owned those plants. So having paid for the stranded costs that were going to occur due to those low, low prices and then finding out we had high, high prices and we were paying again, we said, "Hey hold on a minute, we need to fix this problem."

This is a problem. We should lower rates for consumers. We should do something. And the answer was, first, markets, what are you going to do? And then the second was that old economist crutch, well, you know, the cure for high prices is high prices, just kind of hang out and it will fix itself. In the meantime, consumers paid and consumers paid and consumers paid. So we had to pay a little bit more so that we could get the low prices. Now the interesting thing is they also said, "Look, high prices will lead to market entry, it will lead to innovation, it will lead to new low cost solutions." Great. We're still waiting.

That did actually, strangely enough, happen in the natural gas industry. Those \$13 in MMBtu prices combined with some technology changes led to a push on drilling. We did shale, we found out how to get gas, we have an overabundance and a supply of gas. And guess what? Economics works, prices come down. Great, that's good for consumers. In the markets, well, those high prices never really led to entry per say. So what would we do? We need to create capacity markets because the issue is we're not paying enough money in the markets to get the low prices that we need to see. So we will create capacity markets, we will pay more money in the markets to support capacity so that we can therefore have our low prices. Great. We did that and we moved forward. There is also a transmission element to

this and I'm going to go high level for you FERC folks because I know there are open dockets, but the consumer advocates have always struggled with transmission and the cost of transmission, RTOs and the huge administrative costs of RTOs.

But there's this broad idea that says, "Look, you've got to build transmission because ultimately, if we want to support these markets, if we want these markets to work, and if we want these markets to deliver low costs to consumers, we have to have transmission." They're the grease on the wheels of the markets. That's what reduces our congestion costs that reduces our out-of-market dispatch. So it's okay that we pay very high return on equities, we pay hypothetical capital structures, we pay RTO bumps on ROE, we pay all of this excess money for transmission because ultimately, again, if we just pay enough then we'll get our low prices.

And so we've paid what we believe are fairly rich prices for transmission to get our low prices. Now we're also seeing this phenomena in the distribution side, and I know this is not really distribution oriented, but what we're seeing now is a massive push at the retail level, local level to rebuild utility transmission, or excuse me, retail utility distribution assets because we're going to have smart grids, we're going to have distributed resources, we're going to have responsive pricing. We just need to spend a little more money so that we can, once again, capture those efficiencies, get low prices for consumers. And I think the slide that Speaker 1 had showed that one of the, if you look at a consumer bill, yes generation prices have finally gone down, finally distribution and transmission costs are going up at a pretty rapid rate on consumers' bills.

So we find it difficult to have finally arrived at a place where we're getting the low prices on the generation side and we're back to square one where at the individual states, and I'm not here to

say any individual state is approaching this in the correct or incorrect manner, that obviously is a state level question, political, but at the state level they're saying, "Look, we need you to pay more money, consumers, to keep our low prices, whether it's subsidies on nuclear or other things."

I think there's this struggle again that we talk about efficiency, we talk about markets, we talk about what we want the markets to deliver, and we've finally maybe arrived and we're sort of wrapping ourselves around an axle to figure out how to not deliver that for consumers. Now I only tell you this little bit of a story because, from the consumer side, we feel like we've paid and maybe, just maybe in this instant of time, we've earned the low prices that we're getting. So leave them alone.

I would also suggest, and I think this is actually not out of line with what Speaker 3 said, you know, maybe the cure for low prices, as we said before, is just low prices. The markets are going to adjust. Eventually, as we put the technology on the distribution system for consumers to take advantage of, perhaps, the low prices in the duck curve in California in the middle of the day or the low prices in the middle of the night in the middle of the country due to excess wind, people will adjust. As we look forward, low prices may take care of themselves and so this is not really a problem that we should be in haste to fix. And then finally, and I just want to throw this in, nobody has really talked much at all about storage.

In this whole discussion we've talked about renewables and markets and transmission and generation and I'm sort of of the belief that storage is going to have a huge impact on how we go forward. And frankly, I think it's going to probably on one hand provide a lot higher levels of efficiency in terms of how we operate the

system and what can actually be delivered to customers on a local level and it might exacerbate in great measure some of the generation challenges that we have. So I just want to throw storage on the heap because I don't think anybody has even mentioned it today and I think if you look out 10 years, storage is going to be a game changer. But again, I tell you all this because as you go forward in whatever it is that you do for your day job and you confront these problems and you have these high level discussions in high level, with high level people in rooms like this and you're trying to come up with some answer to this problem, in the back of your mind I just want to plant this little seed.

I hope that this seed gets planted that as you have the discussions, you take a moment and you step back and you say, "How much more do I need customers to pay to get the low prices that we deserve?" I think you should always ask yourself that question instead of just going about solving the problem that, really, we don't need you to solve right now. So not a highly technical discussion, but an important discussion. The world is not bad for consumers right now. It doesn't need help. Thanks.

Moderator: Clarifying questions?
[LAUGHTER]

Question: Thank you very much for that and it's hard to ask a clarifying question on that one.

Speaker 4: Strategic. [LAUGHTER]

Questioner: When you think about low prices, the focus has been on the prices that energy markets produce. What about the dollar that's coming out of the consumer wallet for things that are outside of the energy market, like externalities that are now being priced in in different ways, it might be a ZEC or an increased REC as RPSs increase? So when you talk about low energy

prices, I get what you're saying but there are also new heretofore not seen charges that consumers are bearing. Could you just comment on that?

Speaker 4: Yeah, we don't like those either. Here's the struggle. For the purposes of this discussion, I was trying to be very oriented around generation markets and what we're trying to accomplish in generation markets and what's going on there. And again, generation markets seem to be working pretty good by our accounts. We're getting low prices. But yes, on the other side of the equation, states are responding to the low prices and cries to their utilities or at least their local constituent about loss of revenue and the political reality of jobs and displaced workers and those kinds of things.

All of which are extremely valid political points but they're not really part of a pure economic equation. So we struggle with those questions. If you look at the different state proposals, I will tell you that my members have different reactions in the different states that you're looking at. Some proposals, I think, are designed better than others. I can't comment on whether it's good or bad but I would not that the ZEC proposal in Illinois at least had a range where if power prices stayed up, they had to give some of the money back.

Not necessarily a bad idea. But, yeah, we struggle and have always struggled with sort of the retail level, what's the total bill to consumers and what are the drivers, and we could have a whole separate conference on the distribution side of the utility and some of the things that we're paying for in terms of upgrading the distribution system and what we're getting for all of that. And change is probably, again, there's a whole separate conference you could probably have on how we modernize and make more efficient the connection between the distribution and the generation system so the consumers see prices more readily so that we can actually get

people to behave in manners that would be beneficial overall. Again, that's probably a whole separate conference too other than this one.

So yes, at the end of the day it's the total bottom line bill for consumers and it's the electric bill plus the water bill plus the gas bill and then whether you most people have at least a telephone bill if not something. So it's the total package of energy costs for consumers that we are concerned about and there are a lot of external factors and things on those bills that we are troubled by.

Moderator: Other questions?

Question: So I see what you're saying but when you go from high prices to low prices there's this wedge there that creates an opportunity for all kinds of public policy benefits or investments in resiliency or assets that we want to keep around or transmission projects that contribute to reliability and you can do that without actually lowering the prices because the wholesale prices from natural gas have gone down and we've got this opportunity to fill that gap with all these other things. How would you respond to that?

Speaker 4: Well yeah, that head room argument, we're not a fan of that argument too because what you're basically saying is that instead of transferring the low prices to consumers, we'll just find new ways as administrators to spend your money on things that we think might be good. [LAUGHTER] Again, if you want to regulate the markets, let's have regulated markets.

But there's an infinite possibility and an infinite number of opinions on perfectly valid and reasonable ways that each of us would spend money on our pet project. There's a million hands at the table looking for money. I urge caution in taking that head room idea and saying, but we could do all of these other things. And

frankly, the reality is, that's what happens. It's happening right now. If you look at, again, distribution level prices at the utilities, yeah, they're starting to take up that head room. The natural gas utilities are very active in this space: Oh, the natural gas prices are down so your gas bill is down so why don't we invest, you know, hundreds of millions of dollars or billions of dollars in infrastructure renewal? At some point, again, it's not our job to just keep thinking up ways to spend consumers' money. How about we just take a break on that for a while.

Moderator: In the back?

Question: Can you talk about reliability for a second? In particular, the thesis that we don't need to address low prices right now. It seems like there's an assumption built into that that either the lights will stay on or that consumers will be fine with lights going off and letting the market respond. Is one of those assumptions built into your thesis or just can you speak generally about how you view reliability in this context?

Speaker 4: Yeah. So I don't think reliability has really ever been an issue because we have the engineering knowledge to meet and address that. I think that's going to be the case going forward so I'm not hugely worried about reliability. That's what we have RTOs sitting out there, for the most part, NERC, RTOs, we have a huge infrastructure set up to make sure that the lights stay on and I think that they will. I think that reliability argument becomes a foil, again, to go, wait, here's a theoretical possibility, we should spend some money to avoid it. How about we walk forward and wait for NERC and the RTOs to tell us that we have an actual reliability problem and then see how things get addressed?

Again, there's an awful lot of variables at play. I just don't buy into the notion that all the generation is going to leave the system and the

lights are going out. I just don't think that's going to happen. I think that at some level, yes, as things get tight you see prices come back up, we've seen that in Texas, that was on Speaker 3's slides, so some of the cure for low prices is low prices. But again, there's the possibility and there's the probability. Yes, the natural possibility is in your question. The real probability of that happening, I think is low so that's just kind of the way we approach it.

And again, investments will be made, consumer preferences will change, distribution level usage will change, storage will come into play, a lot of things will happen. And I don't mean to sort of shush over minimizing some of the challenges as we look forward from some of the new state level renewable requirements. These are going to be challenges that we have but at the end of the day, do we really think the lights are going out? No, I don't think so.

Moderator: Other questions? We used up your coffee break. Ashley, turn it over to you.

General discussion.

Moderator: So that was a tremendous presentation from all of the panelists and now let's try to unpack some of that in a discussion.

Question 1: So thank you to the panel for their presentations and I particularly want to emphasize a point that Speaker 3 made along the way about the Texas, the evolving Texas experience which is when the initial debate took place about the operating reserve demand for urban scarcity pricing, it was in the context of, should we do something or should we have a capacity market because we have an impending crisis of low capacity and we're not going to be able to meet the requirements for load and all that stuff. And they went through this long debate and

then they decided to go with the operating reserve demand curve and not to have the capacity market and then the next year, the impending crisis was delayed a year, but we're going to have a crisis the next year and then the impending crisis was delayed a year and so on. So finally, this summer we started to get something where prices actually went up in a way that I think is actually instructive and quite helpful.

There are a couple of points in that story. One is, we don't know what's going to happen so a lot of these attempts to forecast precisely what the outcome is going to be and then do a lot of mandates around the outcome are going to get us in trouble whereas if we get the structure right, then the market responses will be appropriate given what actually happens as we evolve. I think that experience is extremely important because it gets to another point which is the actual question which is the goal, Speaker 4, is not low prices and the goal is not high prices, the goal is prices where marginal benefits equal marginal costs. I don't know whether that's low prices or high prices.

So when they had too much capacity in Texas, low prices were the answer, they weren't the problem and when they don't have too much capacity, higher prices are the answer, they are not the problem. What I'm worried about and I wonder, I should think you would be more worried about today, is the story you're hearing here about the impending deluge of future stranded costs and who is going to be paying for those stranded costs. I don't know which of the mandates that we're imposing is going to turn out to be the bad one, but I'm quite sure that some of them will be and then we're going to have very high stranded costs and it's going to redound, the customers in the end are going to argue that they should be paying those in situations where it's not a market choice and not a voluntary choice. How are you worrying about that problem and trying to make sure that the decisions we're making

today are better at balancing marginal benefits and marginal costs rather than just trying to keep short-term prices down?

Respondent 1: Well, I do recognize that for purposes of tongue-in-cheek abridged stories, low prices is sort of the bottom line and I do understand that markets are about creating mechanisms that lead to efficient outcomes. But we still like efficient outcomes that are tied to low prices so I'm just going to say that. Let me touch on that in two places.

One, yes, we are extremely concerned across the board about the various mandates that the states are coming up with and some of its solar, whatever they are, we are concerned that things are going to turn around to be stranded costs or the resources that we're building are going to strand assets that are not stranded at this moment. That's a concern I didn't really touch on. So we talked a lot about the third of the states that said, "Yeah, let's do that." There was the second third of the states that said, "No," and they're kind of in the middle of the country. And they did come around to markets and they did come around to creating RTOs, MISO, SPP, but they're still vertically integrated and they're energy markets only right now and they're allowed or able to do that because there's just a lot of ills buried and retail rate base, and I think that that is going to be an issue going forward as there's a larger and larger disconnect between what's getting dispatched and used in the market and what is sitting on utility balance sheets in those vertically integrated markets. We're going to have a big discussion about stranded costs there.

So, yeah, stranded costs is a big issue, both what is sort of sitting on plates right now and how we, I guess to say it bluntly, how we keep decision makers from, again, stacking up and using the head room. I don't know where Abram went, but using that head room to come up with a lot of new

decisions that will ultimately rebound back to states and consumers and a new form of stranded costs. So I don't have an answer for how to solve the equation but I will tell you, yes, it's very much a concern in terms of what states are doing and how we're stacking these up. But I can't solve that problem for them. I don't know if that's a good answer but –

Questioner: If I could follow up just, let me suggest an example of an answer which is, mandating certain technologies because we think they're desirable is quite different than imposing a carbon tax and a price of carbon to attack the thing that we actually find undesirable. And the connection between the two is weak and so you don't know what it is that's going to substitute for what. California is already experiencing renewable substituting for renewables so that's a policy position for your group. We like carbon taxes because that actually targets the problem that we're going to have to deal with, it doesn't create stranded assets, it poses the risk of the market players who are participating to respond efficiently. So I'd like to come out of this meeting with you happy. [LAUGHTER].

Respondent 1: Well, I'll tell you this, I do have a masters in economics and I'm right there with you. Yes, let's pick the first-best solution, but we all know that regulation doesn't do that. I would love to have my membership overall come to that conclusion, but that's just a hard thing in a membership-based organization to get so that I would be able to sit here in front of you and say this. It's sort of a fascinating thing.

We actually have, as an organization, we have two, not one, but two global warming resolutions. Our first global warming resolution was in 1998 as an association. But I have to tell you the membership is really much different now, my members being sort of the state office heads that are either appointed or hired, and it's very

different. We have, in some respects, sort of split apart a little bit more so you have a very, very proactive green set and then sort of a set that's not. So we don't even talk about our global warming resolutions much anymore even though we do have them, they do exist, and I can tell you that they exist. I'd love to get there to be honest with you, but that will take some uplift from the membership and as we know from the experiments that are the states, that's hard to pull off across the board. I agree with you though.

Respondent 2: If I could arc in. So I think New York is an interesting example on this point. Right? So the NYISO has been considering implementation of a carbon price within the ISO market and have been doing a ton of work on that. The state has now passed 100% clean and, well, the whole CLCPA is a broad swap, but within the energy sector 100% and by 2030, 70% renewable. Now New York is already 30% nuclear, so by 2030 they will be at 100% clean. They don't have to phase out the remaining fossil until 2040 so that gives a little bit of a trajectory.

So in the context of CLCPA implementation, there's a very live question in the Cuomo administration as to whether or not the state wants to pursue the carbon pricing kind of program through the NYISO. So the collective us should all be pushing for that. This is a very tangible, a very near-term opportunity to establish a meaningful carbon price within a wholesale market that can help rationalize some of these decisions which the state is going to have to make in the very, very near term and we should all be pushing for it. Now I say that because we're supportive of market design. We receive ZECs in New York and the carbon price is going to be an offset to the ZEC because, as was already mentioned, it's not going to help us economically but it's the right thing to do.

Respondent 3: And I'll add, part of the reason

that I express such optimism in New England to try and driving carbon pricing is less because we see it from a regulatory standpoint and more we see it from a political and a legislative one. Where in the six states of New England, three out of the six governors are Republican but all twelve of the legislative chambers are Democrat and a number of them, over the last year and a half to two years, have moved pretty aggressively on that end.

And as we now start to see a focus shift from decarbonization on the generation front to transportation and home heating, I think there is a window of opportunity to look at a much more broad-based approach to this with carbon pricing being a key component, although as I said, in my earlier remarks, not the single policy driver of this overall. So I do think there is a potential movement there, although that conversation will shift in what in New England has been primarily with the governors and the regulators, I think, more into the political and legislative realm which then does create more uncertainty and more variability but an opportunity nonetheless.

Question 2: Hi. Thank you. I had a question, Speaker 3. So it really goes around the discussion you sort of started with this model of having more bilateral contracts, so one observation, and it's certainly clear you have bilateral contracts in some of these instances that you were showing but I'm not aware that there's really been much bilateral contracting for dispatchable assets in ERCOT where we've had bankruptcies. But then probably more importantly, going forward, if the utilities have to play a larger role, which you suggested, isn't that really sending us back toward where we were? How would we make those decisions when most of our standard service frameworks really are short-term and most states don't, in my observation, they just prefer to have the ISOs kind of handle it and then they free ride on that, getting it, I think they think,

at the cheapest price. I was wondering if you thought about whether we're taking us backward with that kind of framework?

Respondent 1: Well, no. I think there is a decentralized market construct that can work to achieve both decarbonization reliability and economic goals. Texas is the closest and I think they're a legitimate choice for any state would be to do full retail competition and the retail electric providers have the job of serving whatever end use customers they sign up to serve. And those customers need not only whatever clean energy they may want or be directed to need, but they need power 24/7, 87/60. So they're going to be looking for contracts to serve those customers, so long-term PPAs with whatever generators, in Texas that's probably going to be gas generators, independent power producers there.

And my understanding is, even in PJM where you have the three-year ahead central capacity market, that there are a lot of bilateral hedge contracts that most gas generators rely on those, not just the three-year capacity market because that gives you one year but they're financing the generation on the bilateral contracts that operate completely outside of the PJM market. So you're financing generation of carbon-free and non-carbon-free power and in ERCOT style and capacity market style regions with these bilateral hedge contracts that are operating outside of the RTOs. And that's the way generation gets financed.

Moderator: I'm going to come forward first and then go back –

Respondent 2: Before we leave that, just real quickly, and I just want to sort of throw this out there, it's more observational, but I think that's good academically but in the political reality on the ground, Connecticut, New York, I think Massachusetts or Maryland, there's a huge push

for legislature to remove at least the residential customers from marketing, from the third-party supplier reseller markets. They, some states, and it's not across the board, but some states have judged that that has just not worked out well for consumers. They've paid more than standard offer service. They're targeted marketing toward low income and less sophisticated customers which has led to problems, and so they're actually in the process of trying to get rid of it. Again, it's a political question as opposed to an economic question. But it's one thing to say, we should go forward with an ERCOT style thing but in the reality, there's actually a lot of states that are pulling back from that at this moment.

Respondent 1: And I'll just say, again, that's another from an RTO or FERC perspective, like, that's another legitimate state choice. And it's understandable, I think, to anybody that you might make that choice. There again, you still need to make sure that somebody is procuring power on that load. I mean, I think it does kind of send you down an integrated resource planning type of function. You have to think about getting power all the time but you can do it in a much more, I did say, competition-friendly way than the past. You don't have to have a utility planning do it, you don't have to do anything in rate base, you can have competitive procurement for serving that load, you can make sure the suppliers are unaffiliated with whoever is doing the procurement, all these sorts of things. So you could have more of a competitive procurement type of competition as opposed to full decentralized on both the supply and demand side, but you can stay decentralized on the supply side.

Question 3: Thank you. A couple of comments. First on the retail competition and dissatisfaction, you could add Maine to that list where it's being questioned seriously because of the overcharging and under-competitive behavior, you might say.

On RGGI, I wanted to add that, and I'm on the board of RGGI, I want to add that when you hear the RGGI board members talk about carbon taxes, generally speaking, there is a reluctance to go forward with it because there is satisfaction with a known known and what you can get out of RGGI as opposed to states coming up with different variants of carbon taxes. We're not trying to talk about a national carbon tax.

But a question for Speaker 3. There's a revenue sufficiency problem that emerges for our T&Ds if you carry forward the concept of distributed generation where distributed generation locates at the most profitable points on the grid. They're not going to go into deep rural areas where there's high cost for them as there is for any other provider. They're going to be in urban centers, industrial parks and so forth. How would you address that in your approach?

Respondent 1: Well, I think the wholesale market structure approach can operate independently of that but I don't work for anybody else so I can just expound on whatever the heck I want to so I might as well. You know, I would say this is a distribution, a regulation distribution utility question and state PUCs have to answer that question of essentially cost allocation for distribution investments. There are definitely going to be increases in distributed energy resources so we're going to have these questions whether you have net metering or not. I guess I would say that almost all owners of distributed resources still use the grid and probably use them about as much as they ever did.

I have solar panels on my house. I still use the local distribution wires as much as my neighbors do. So that's a choice that PUCs have to make and there's a lot of complicated analysis about hosting capacity and that sort of thing and who benefits by how much. But that's a good thing we have PUCs to make those decisions because,

again, the distribution system is a regulated monopoly and they have to figure out what investments are needed and how to allocate those costs.

Questioner: My concern is the impact on other customers left on the grid if there are political preferences given to more favorable conditions for DGE developers. The other customers pay.

Respondent 1: No, I hear you and that's the net metering debate and all that. And I certainly personally have sympathy. I don't want lower income consumers of my utility to be left holding the bag for what the wealthier people are able to do with their solar panels. I mean, we need to allocate costs in a fair way.

Respondent 2: Just to chime, I mean, to chime in on the Exelon, put on my utility hat, you know, that is the concern with the net metering programs.

Question 4: This is just getting back to the conversation that we started about transmission. I'm a little unwilling to move away from the issue of carbon and carbon tax because I'm all for it and I think it's important for this group to discuss that.

But I wanted to return to some questions about the connection between transmission investment and going for a deficient investment in generation. And I think there was a view expressed that we were kind of getting off topic with raising that issue and I don't think it's off topic because I do think that continued deficient investment in generation depends very much on what we do in terms of transmission policy and how the policies are made about what transmission is built and who pays for it because as you all know, the transmission that's built can favor generation located in certain areas versus generation located in other areas.

I wanted to just kind of drive that point home with the example of Texas. And I know there are folks from ERCOT here so if I get it wrong, just tell me. But in ERCOT, there is centralized decision making, as everybody here knows, about what transmission is going to be built, centralized planning for transmission, and the costs to recover based on a 4CP cost allocation methodology. And what this means is that there are lots of people who provide sophisticated services to industrial customers down there about when the 4CP periods are going to be. And the 4CP customers have behind the meter generation and can get off the system when the 4CP hours occur or potentially occur that will determine their cost allocation for the next year.

So there is the incredible potential or ability for industrial customers to avoid allocation of transmission costs that have been built and are intended to be socialized across all customers who are benefiting from the generation that was enabled by the new transmission build. The other point obviously is that the industrial customers have a fairly flat load profile. They are generating many, many hours from the low cost energy being integrated into the system from the new transmission build, and the costs of the new transmission are not being born.

This is relevant to consumers and this issue is very pertinent to equities among different consumer groups and how you deal with those equities. And I guess the question for the panel is, in light of these kinds of problems and their impact on consumer equities and on transmission, efficient transmission buildout, have you considered how transmission cost allocation might need to be changed in the future?

Respondent 1: I'm always a sucker for these things. I'll jump in. You make a great point. I do think transmission and generation are inseparably connected. And as the last question

indicated, the cost allocation is usually the hardest part of the regulated sector, so both transmission and distribution. However, what are we at, 100 years of public utility regulation? Wasn't it Bonbright who laid out the original regulatory cost allocation principles? John, I see you in the back smiling. You know, there's sort of an art and science to how you allocate costs of highly capital intensive natural monopolies. It's not all science. It's not easy. There's not a simple formula but there are principles about how to do that, and I don't think they've changed.

I think if you asked Mr. Bonbright about your case, he would say, "Well, that's the wrong rate design for that particular sector and you need to change how the rates are recovered to reflect a more fair allocation." So again, we have important work for regulators to do, both state and federal, but I don't think the fundamental sort of economic policy has changed for those. There's how much do you build and who pays for it, questions that regulators need to decide.

Question 5: So I guess there's actually a lot of consensus about where we're heading in the markets in terms of at least needing more flexible resources, being able to balance the system, dealing with ramping requirements, having these intermittent resources, and how do we face that challenge.

I didn't hear much discussion of the role of a real active participation of demand response in a physical way in these markets for providing some of those kinds of services and I wonder if we're sort of operating on an original technology or role of the RTOs in facilitating active participation at the distribution at the state level, at the retail level, in the wholesale markets by demand response in order to solve some of these problems because, while there are lots of investments in demand response, it doesn't feel like the market design that we have is geared to actually

providing these services in a way that ISOs could actually rely on them to be providing reliability benefits. Any comments on the role?

Respondent 1: I'll take a stab. As the Moderator mentioned earlier, and again putting on my utility hat, the utilities are in their own kind of era of transformation. And so within the Exelon family of utilities we have what we call the Connected Community Strategy but essentially it's the evolution of our systems to a platform-based model where we understand in a more clean system we are going to have more distributed resources on the system. The nature of our systems at the distribution level are going to change and that's going to have corresponding changes at the transmission level which takes us to all sorts of fun rate questions like was just raised. But it's undeniable. I didn't mention them because it just wasn't what I chose to focus on but we will have a more distributed future, demand will play a more active role and that's incumbent on us to enable that as at least from our perspective.

Respondent 2: And I will say specific to New England, we've seen a bit of an evolution on that front in that I think about a decade ago we saw the exuberance around demand response and playing a larger role. That's really been pulled back and instead what we see playing that larger role is both energy efficiency and a tremendous spend at the state level to drive that, having an impact on then the amount of capacity that we end up having to buy through the capacity market and then what Speaker 4 raised before the break of storage and creating that as that customer phasing approach and integration.

And so it doesn't play that same traditional role of DR as how I think we've all thought about it in the wholesale market but it starts playing a very similar function collectively. And I think that clearly is where a lot of this is going and we're

going to see more of that customer empowerment, although I do have questions about what is going to be the overall peak impact of that in a place like New England where certainly we still are a summer-peaking system but it has been discussed *ad nauseum* we see the most tightness on the system during the winter months.

It's in those periods of time where particularly most of the distributed solar is co-located with solar and it's hard for the solar to operate under a foot of snow on cold cloudy days. And to what degree will we see performance from those more distributive storage resources in that type of a situation where it's a seasonal issue, not an annual issue? Annually I actually think they perform very well in New England but in those seasonal periods, how does that function? That, to me, is still a knot that hasn't been untangled specific to my little corner of the world.

Comment: Could I just comment on that because I think it illustrates the concern that I have is that demand response has sort of been conditioned to focus on being a capacity market resource and energy efficiency in response and so all the demand response they're developing, because we've institutionalized these excess reserve margins, with the capacity markets, you're not really getting either the scarcity prices or the high prices either for the fundamental reason you have too much or just the problems with the market design around price formation and you get this focus of distributed generation or demand response being in the capacity market.

And to me, that is where the market design challenge really is, to be able to shift to a place where it can really be a resource. And I don't think that should be incumbent on the utilities to do that and put that in rate place. I think it should be incumbent on the state regulators and policy makers and the ISOs to figure out how to bridge

the gap with market design that incentivizes active physical demand participation and sends the right price signals so the demand response would be involved. Because I think the market design is actually heading in the wrong direction.

Respondent 3: I agree with you. There are 31 flavors of demand response and they all have their own sort of nonconvexities and capabilities, just like different generator types do, so I think there is a market-based answer to this one too. I'm hoping part of the postmortem of ERCOT 2019 shows that retail electric providers found more and different creative ways to manage the load that they are serving in offered incentives or whatever it is or they all had Nest thermostats and they were controlling remotely.

Whatever it is, there's room for a deal there. They saw the high prices coming. The electric providers would have to pay it unless they managed their load or bought new supply and there wasn't much new supply to buy so that's how it would work in a competitive environment and there are many ways to do that. And the homeowner, itself, doesn't have to pay attention to prices. You can have your provider do all of that.

Question 6: Speaker 3, a question for you about PPAs. Today, just in terms of normal hedging, there are intermediaries, Wall Street banks, who will buy up everything a generator can put out in what I'll call long-term PPA and then they'll dice it up and sell it to retail suppliers in whatever the appropriate timeframe that the retail suppliers want.

Is that the model you're envisioning for renewable? Because I think what might be confusing is some states in the past have ventured into requiring retail suppliers to enter into physical hedges with certain selected resources to meet their policy initiative and that seemed to run

afoul of retail competition practices. So I want to just make sure that you can clarify for the audience what you mean.

Respondent 1: Sure. Well, I don't know that it matters so much what I think but it, I'm saying that in this presentation, there is a market-based model that can work for decarbonization and all the other things. You do have to internalize the externalities and do a number of other things but you could have as part of that model, voluntary bilateral contracts that lead to long-term PPAs that finance generation.

Now, again, ERCOT is closest but it's not fully there. We don't have a, you know, fully sort of working model to point to. Outside of ERCOT, there's market imperfection on top of market imperfection so I can't say what any given state should do from where it sits but certainly if I mean it is a state's choice to choose what kind of resources and how they get it, so I guess my main point there is it's not really the RTO's or FERC's business to tell them how to do it, that they can do it either way and just come into the spot market when you want to sell or buy power on the short-term basis.

Question 7: Thank you very much for that question, because it's almost exactly what I was going to ask but I'm going to ask in a different way. Also, thank you for your presentations today because, although they've been very informative, there's many things I'd like to ask but can't but this one I've just checked on our website to make sure it's safe. You've talked about bilaterals, you've talked about state policy requirements, you've also talked about the need to have creditworthy buyers and I want to try to pull some of these threads together by asking this question.

This case is now, as far as I understand it, absolutely dead on the FERC dockets but is it

possible that by taking a second look at our Edgar and Allegheny requirements, that we could get out of the state's way for achieving its public policy objectives? And Speaker 2, I don't want to make you feel uncomfortable now that you're at Exelon, I realize your company took a contrary position in the Ohio case but maybe is it time to rethink that?

Respondent 1: It's live in the FRMOPR proceeding.

Questioner: What's that?

Respondent 1: It's live in the FRMOPR proceeding, so the issue was raised in that docket. God, sorry. [LAUGHTER] We raised the issue in the docket so, sorry. [LAUGHTER]

Questioner: Well, thanks, anyway. [LAUGHTER]

Respondent 1: Read our pleading. EBSA did have something to say in response. [LAUGHTER]

Question 8: I guess my question is probably a little bit more higher level. I think this debate has been happening for the last, I don't know, has been 15 or 20+ years, I think the fundamental question is when we delegated markets, there was a set of market principles that led to the creation of the markets and every time, whether state intervention happens or some other intervention happens, the market rules change and that slowly creates some kind of stranded assets for the market participants.

And I think the question over there, you know, whether, Speaker 3, your solution over there is bilateral contracts, that's great but now you're going to leave and then you have residual margin of, in PJM, 30% or in other places where you have no other than 10-15% residual margin, the

bilateral contracts will leave some people not participating in the markets.

So what do you do with that? Are you going to let them say, you know what, now you're going to participate in it or are you going to give them a standard stranded cost recovery for them because they entered the market on a set of principles. I think the problem with any of these approaches, and this is probably my opinion, I'm not going to argue with any of this, is either you play in a regulated space where you have a cost base recovery or you go in the fully market space and don't let the markets change. You create a market principle, don't let it change. Every time you let something change, there will be some creation of stranded assets. It might not be big but at some point it becomes bigger and bigger.

So what are we trying to solve? I'm still puzzled by this. Are we trying to solve whether the original market creation was a good idea or a bad idea or are we trying to solve, what is the ideal market principle?

Respondent 1: So I'll take a first crack which I think goes back to some of the prior discussions of the first-best choice is, I think, where you're getting at, either we go to a fully regulated environment or we go to, essentially, a peer-based market-based environment. Tony Clark, I know he spent a lot of time coming to New England and other places making that exact argument. I've made many of those similar arguments in the past and yet, the reality of what we have is that imperfect second, third, twenty-fifth best choice, it's going to be a mix.

We're going to be half-pregnant for a little while and I think the challenge we're struggling and the fundamental question we're trying to answer is, how do we create a durable sustainable structure in which we have both market-based elements and a high degree of regulated cost-based

elements. And I think the tension and the struggle that has come out in this discussion and in the discussion we're having with the audience is there's not a great single answer to it and we're trying to muddle our way through and figure out what are the best ways to internalize costs and then design market-based products around that. But that's the way that I think about what we're trying to unpack.

Respondent 2: And I was just going to add, there is a workable market-based model and in that model, yes it does rely on buyers and if you're a supplier who doesn't have a buyer, that is your job in a market to go find the buyer. And I think there's been a lot of confusion in restructuring, thinking that the RTO is the market. And there are market monitors at the RTOs who say, when you go out and sign bilateral contracts or whatever, you're going outside of market. And it's like, where did the RTO become the market? Yes, they're running a real time spot market for longs and shorts and they're kind of the air traffic controller.

And if you're going to do that, as Bill taught us all, if you're going to do that physically, you might as well do it through an auction-based system to be more efficient. But they're not your customer. We were trying to set up markets when FERC and many states did this and Congress passed EP Act in '92 and markets rely on buyers. So the job when you go into a market is to go find your buyer and if you're the supplier that wound up without a buyer, it's kind of musical chairs and you got left without a chair. And you were supposed to go find them.

Respondent 3: I guess I would just throw in, in the real world and real markets, things change; tax law changes, policy changes, things change, some people win, some people lose, losers go out of business, their assets get sent into bankruptcy and possibly bought up by somebody else and

reused in the market. There's a whole efficient sort of system out there for doing that but for whatever reason in our own system, it's kind of a no-losers adventure. We seem to keep finding ways, which was sort of the point of my tongue-in-cheek version of how many ways can we make consumers pay to get the market to work and produce low prices, even if that's not exactly the right answer.

But you know, in the real world, people lose money. In this world, people, if they lose money, they like to go to the state legislature and get a bill passed or get a ZEC passed or get a change in the market. There's no way that this market, that this whole sort of adventure proceeds 10 or 20 years into the future with the changes that are going to happen, that there aren't going to be losers, that plants aren't going to close, that money is not going to be lost.

If we keep trying to protect everyone from losing a little bit of money in these markets, then you end up with responses that somehow keep layering charges on consumer bills and that's not, you know, I'm always amused, and it was even in the New England slide that Speaker 1 had about the New England commissioners all say, there's always this word, affordable. And every time they make a statement about whatever is going to happen, we're going to do what's going to be affordable, we've got to, we're responsible for affordable energy. But there's no actual bounds around what affordable is. Nobody has actually defined it. It can be any damn thing you want. It could be three times what it costs today. Is that still affordable? I don't know. We just keep putting charges on the consumer bill.

So, at some point, yeah, find the structure, find the thing that's efficient, let the chips fall where they may. The utilities may lose some money, you know, the marketers may lose some money but that's the way it's supposed to work. And we

on the consumer side are kind of a little skeptical that it's ever going to work that way. And some of that's, again, not the market, it's not FERC. I mean, a lot of that ends up happening at the state level, because governors don't like a plant to close down and don't like jobs going out of the system and things that technically shouldn't be within our market framework but, politically, they are. But you know, again, that's where consumer costs start adding up.

Respondent 4: I have to jump in, if you don't mind. In New England, 70% of the generation post restructuring went bankrupt, 70%. When NEPGA was started, it was four companies and then it was 19. Most of the companies don't exist anymore. There's been M&A activity, some have closed, some haven't come back, we don't like coal in New England so that's pretty much gone.

And so people did lose money, but that risk was on the power producer, it was not on the customer. Markets did what they were supposed to do there but whatever happened then, now you have a different, a whole different paradigm. And I said this earlier in my probably boring opening remarks, but I was never a fan, back when I represented customers, generators, or even as a regulator of PPAs but that's what we have and that's what you have to do. And you're not going to be able to discount what some of these states are doing. You know? And this comes from a state that has the largest clean energy procurements in the country, if the feds would get the hell out of the way, for offshore wind and hydro to bring in. And this is a state that puts their money where their mouth is. And we argued and we fought with ISO and the ISO board and FERC and those were wonderful discussions.

But you've got to find a way to bring them in and to work with the states. And I am an eternal optimist that, if there's any region in the country

that's going to figure this out, it could be New England. But what it looks like is not going to be what it looks like today because it's flat load growth with all the investments. And on the DR side, there's been a ton of investments in New England in that area and I think the ISO recognizes that. The forecast of what's needed is lowered all the time because of energy efficiency and stuff going on behind the meters. So they are looking at it and they are doing what they can.

I don't envy ISO New England for trying to juggle all this and keep the lights on. I don't envy Speaker 1's members that are trying to, you know, is there enough money because you're going to need some of these traditional resources, including the nukes, to keep the lights on. And you know, what are we 24% nuke in New England we've got two huge plants left. And so, you know, I don't know what the magic secret sauce is here but the states are in this game now and they're in it in a big way. And I'm not sure you're going to be able to, you can't just say no.

Questioner: Oh, I wasn't denying that at all. I think the question is –

Respondent 4: No, I didn't mean to suggest that you were, but that's a different player than it was 10 years ago, I think.

Questioner: Yeah, I was only trying to distinguish a true market, like I think Speaker 4, you mentioned about that, every other market, commodity market, for example, the supply demand forces are pretty much uncontrolled. Here, for whatever reason, the supply demand forces are controlled. Like for example, energy efficiency mandate for example, the demand is controlled. You're artificially interjecting forces into the demand side of the equation and supply out of the equation so it's truly not going to be at market as you want it.

So I'm not denying the fact that you're finding that the twenty-fifth solution or what if it's not the first solution but I think we've got to realize that that is the mode we are operating under and you're never going to have a perfect market in this space. So you know, that's all, I wanted to make that point.

Respondent 4: I would ask, is there a perfect market anywhere? Or has there been?

Comment: Well, it's an unfair question because we know that we're balancing many different objectives at the same time. But I do think the difference between second-best and twenty-fifth best is worrisome and we could do a lot of these things a lot better. So, for example, Speaker 3 mentioned the basic generation service approach in New Jersey, which other states do similar kinds of things, but that's, and he made a slip of the tongue and said we can also go to full integrated resource planning, but that is not what that does. As a matter of fact, what it is, is a three-year rolling contract for delivered energy.

The regulators in New Jersey have no idea where the energy is coming from nor do they care, and they're not managing the construction of those power plants and doing all that kind of thing. And the people who are competing in that contract are turning around and then hedging through various, and some of them are the financial entities. And all of that is built upon the bedrock of the short-term spot market in PJM which you couldn't do if you didn't have the short-term spot market, then you would have to worry about where is this power coming from and all the other kinds of things that you get into.

I think we could do a lot better than we are doing in many of these places and I think we're shooting ourselves in the foot in New England and I think we're going to be really unhappy later on, particularly in Massachusetts. Me, I've got my

own pictures of my neighbor's solar rooftop things that I'm paying for, and so I think we can do a lot better. We're doing better in some places but it's amazing how difficult it is to make these improvements but I think they're eventually coming. And it is a bit of a race. I don't feel like I'm winning, but I do think I'm very worried about certain regions of the country, particularly where I live.

Respondent 5: If I could just add, I think we're circling around, if we had a meaningful price on carbon in the markets it would address a lot. Take your point that a lot of the changes to date have been really policy driven in a different way. Regulators have to decide what resource adequacy is and then you can say, in Texas, well we don't do that, we let the market decide but the ORDC does it. Somebody is deciding that.

And so there's a certain level of market intervention that's going to occur just by setting up the very structure of the market. And then you layer the carbon reduction piece on it and I don't see how we get out of the struggle, the issues that you're struggling with. A meaningful price on carbon we get, it is a very long way there. Hopeful, maybe glass half, it's not quite half full anymore. And so we're going to be in a world where states are pursuing policies that are, the preference would be they be technology neutral but the reality is that they are not. You can kind of throw a stone at ZECs. TMI just shut down.

It's going to take 12 years of Pennsylvania's AEPS Tier 1 build to fill that emissions hole that was created. IT was a decision by the state. Other states are making other decisions. And we can't deny it, we can't avoid it. Think to the point that was made, we have to figure out a way to achieve the greatest level of efficiency we can within what we're given.

Question 9: Hi. So I have a question about

another part of the demand side of the equation, which is electrification of transport and buildings. There, you've got the potential for behind the meter energy storage and I'm just curious about asking the panel to speak to how market design can help make those other pieces, perhaps of decarbonization policies in the states and maybe broader later, happen in an efficient way.

Respondent 1: Well, you probably find a lot of fans for electrification and EVs, and integrating that into the wholesale power market certainly would be great for the overall renewable and clean energy portfolio which, I think, RFF is working on as well. Market design-wise, I think one interesting thing we haven't gotten into today is how much assurance does a grid operator need how many hours ahead of time of its kind of load generation balance?

And you could say from a renewable perspective, I'd like to say we don't need day ahead markets because those were designed for the particular engineering features of fossil units. And with wind and solar, you have a really good wind solar forecast four or six hours ahead of time, so let's just go to kind of hourly spot markets like that. But on the other hand, if you think about the flexible sources that the grid operators need all the other times, think about this building, there's a lot of heating and cooling load in this building that they can actually plan for six hours, twenty-four hours, thirty-six hours ahead of time.

The same for electric vehicles, you plan for the charging and somebody on behalf of the EV owners can be telling the system operator, here's how much I'm going to use or going to need a day or two or three days ahead of time. And I'm told there are a lot of demand side sources that would very much value the ability to have, like, a multi-settlement system one, two, or three days ahead of time in order to voluntarily sort of lock in that resource and plan. And you might see a hot date

coming up and you can actually cool the building ahead of time and that sort of thing. So I think that is a very valid thing for market design.

We're probably a ways away from that because we already do have real time and day ahead markets, but there are questions, I know in ISO New England and its energy security process that Matt White and others are working on in terms of how much and how far ahead of time does the grid operator need resources locked in. MISO is looking at that three-day ahead market and I think it's coming up in PJM's field security discussion as well. So I think it relates to the demand side as well in terms of this how much and how far ahead of time should grid operators lock in resources, at least financially lock in. I'm not saying do make whole payments.

Respondent 2: Another thing that I would add is mechanically, so I think your question assumes or presumes the ability to aggregate a significant amount of resources on the distribution system in order to bring them up to the wholesale market and there's an open rule-making proceeding at FERC on this question on kind of participation

models and what that's going to look like. And one of the big issues that was raised there was the implementation questions that California has worked through and having aggregators on the system interacting with the wholesale market.

Each RTO is going to have to learn through these issues of what's the visibility going to be, what's the relationship and accountability between what's happening on the transmission system and the distribution system aggregated over what nodes and, so a lot of mechanical stuff is going to have to have problems identified, solutions developed and then implemented, and that's just going to take time.

I think, at least from our perspective, we're there and we believe we should be working on this stuff but they're not easy and just to have that type of aggregated distributive resources immediately participating in the wholesale market because they want to get that wholesale price, that market signal without all of the necessary coordination in place, makes us nervous.

Session Two.

California Electricity Crisis (2000-2001): Legacy and Lessons

According to Wikipedia, "[t]he California electricity crisis, also known as the Western U.S. energy crisis of 2000 and 2001, was a situation in which the U.S. state of California had a shortage of electricity supply caused by market manipulations and capped retail electricity prices. The state suffered from multiple large-scale blackouts, one of the state's largest energy companies collapsed, and the economic fall-out greatly harmed Governor Gray Davis' standing." Around the world, this experience is cited as anything from a cautionary tale to an outright dismissal of the viability of markets for electricity. The costs were enormous, and the reverberations continue to this day. Yet both the "truth" and the "facts" remain controversial. Was this as simple as inefficient pricing (In February 2001, California Governor Gray Davis stated, "Believe me, if I wanted to raise rates I could have solved this problem in 20 minutes.")? Unexpected scarcity? Market manipulation? State and Federal regulatory responses at the time were conflicting and sometimes counterproductive. And the conditions extended well beyond the borders of California. What have we learned from this market and regulatory design experience? How

does and how should this experience inform current and future policy with respect to markets and the electricity system?

Moderator.

Well, we'll go ahead and declare liftoff here. So, one thing should be apparent. The passage of almost 20 years is indeed enough to render any *ex parte* concerns about the California Energy Crisis moot. [LAUGHTER] I thought about this. I thought about it when I lost the 9th Circuit case in 2016. There's a few driblets and drabs. Trust me they're not coming up here. I've also been thinking about what the hell was I doing in 1999 and 2000?

The crisis started, I want to say May 10th, 2000, was generally the day everyone pointed to. And that was just after we discovered Y2K did not actually end the world as we know it. [LAUGHTER] Bush beat Gore happened. Nobody counted chads in Broward County. 9/11 hadn't happened. I spent some time trying to figure out what my cell phone looked like because I don't know about you, but I really don't remember two iPhones ago; what cell phone did I have? So, I went online and I think I had a Motorola Razor except, oh, that wasn't out until 2003. I don't know what I had, but I know iPhones are a lot less than 20 years old and they changed everybody's lives completely.

But I also have the sense that we all keep litigating and fighting about the exact same things as we were fighting about way back then. Our market's supposed to throw off net revenues, net contributions to margin that over time on average, approximate long marginal costs. Maybe not as it turns out. What did these markets do anyway? The California ISO's motto before the crisis was reliability through markets, as I recall. Which in the final three trials, in the California refund case, I put in the record, it did me no good, but it seemed to me reliability markets would mean somebody bills on market revenues. What else would you think it would mean?

But we didn't win that case and the final, good old driblets and drabs about fighting about the

summer of 2000. Now we're in the record books. I'll give you one more story about the passage of time and then I'll click on my little slides. I'm going to be brief because they have a lot to say. I'm going to try and just be entertaining, but I'll have you know—and it's too bad David Rask is not here, unless he snuck in—that during the first two trials and Joel Newton, now ex-Donahue is my client for the first one, my paralegal was a great lawyer and friend of mine named Denise Buffington. We hired her from Steptoe. Between the time of the second and third trial in this long running saga, she went to law school. She came and worked for us as an associate and then she went in house at Great Plains only to discover that Great Plains had acquired a long defunct energy trading firm called Aquila and she was back in the middle of the California refund case at which point she hired me to go do the third case. That's how long this lasted.

I mean 20 years is half a career for most people. And in fact 100 years ago, 20 years was enough time to be a father and a grandfather. We don't do things that way anymore, but it's possible. So, here we are. And let me see if I can work the AV. So, who knows who Senator Steve Peace is? Senator Steve Peace was the Chairman of the Senate Energy Committee in California and he's generally considered kind of the godfather of AB 1890. Read what he said here because this is market manipulation writ large actually, particularly the last part. It's fraud in connection with FERC jurisdictional transactions. It was a bet most of the industry nationwide would misperceive what we were doing in overpay for power, meaning overpay for power plants. A bet overpaying for power plants, get our consumers off the hook for paying your stranded costs. That worked very well.

Well, it worked very well until it didn't, which we're going to hear about later today. Now, who knows what else makes Senator Steve Peace famous? Don't say what it is, but you can raise

your hand if you know. [VIDEO STARTS]
[LAUGHTER] You cannot make this up.

And I'm just going to announce in advance, there're eerie parallels between the plot of this movie and the California Energy Crisis. Wait until you see what I mean. This is just for context, so you see what happens when a killer tomato attacks somebody on film. [MUSIC] San Diego, ladies and gentleman. I give you San Diego, California. The epicenter of the California Energy Crisis. This is also the location where the killer tomato's attacked. Notice the high quality of the video. It's worth it, trust me. [LAUGHTER] It's almost done.

Speaker 1: Are you sure this isn't a porn movie?

Moderator: I mean what fertile mind invented this? And he wrote the California Restructuring Legislation. OK. Now keep it down. I've got three more of these, but they're briefer than that one. There, I'll have you know. Ladies and gentlemen, that is Senator Steve Peace. I'm not making this up. This is actually really what happened, but wait until you see the five bureaucrats in Washington, D.C. They're about to come up. There they are. They plead their case in front of five bureaucrats in Washington, D.C. The people, San Diego, doom. They get nowhere. I told you it was quite a lot. To some people the California Energy crisis. Now, just to let you know, they could come back at carrots. All right, you can turn on the lights and I'll pass [VIDEO ENDS] the instruments of torture to Speaker 1.

Speaker 1: By the way that was one of George Clooney's first movies. He was in it as well.

Moderator: Really?

Speaker 1: Yeah.

Moderator: It's on my iPad. I'll have to watch it maybe, and see if I can spot him.

Comment: Aren't you glad we all showed up?
[LAUGHTER]

Moderator: You learn something every day.

Speaker 1: So, I've devoted a large part of my career trying to avoid watching that movie. [LAUGHTER] And you ruined it. [LAUGHTER] Well, when we were discussing with the Moderator about this idea, which he assured me was now legal, or wasn't going to get anybody in trouble, it seemed it certainly wasn't too early to have this conversation. And what I have decided to try to focus on is the part that I hope is part of the legacy question and the lessons. The subtext here is that the California ISO PX design was quote, "fundamentally flawed," and the quotes refer to an order that came from the Federal Energy Regulatory Commission, and I'm going to show that. And basically, what I want to do is to advance the slides so that I can give my talk. Somehow this is—

Comment: Try a green one. That works.

Speaker 1: I did. It's not working. It's been eaten by the tomatoes. [LAUGHTER]

Moderator: You know, at the end of the movie the people in San Diego lure all the tomatoes into Qualcomm Stadium and stomp them to death, because the tomatoes cannot attack when they hear some crazy song called "Puberty Love," or something like that. So, tomatoes just disintegrated.

Speaker 1.

What I want to talk about today is the run-up to the California Energy crisis in 2000 and 2001, of what happened before and what I'm—thank you. Obviously, this was a terrible situation. I don't have to emphasize that, but there was a cloud on everyone's horizon. I've encountered this all over the world. Everywhere I go, particularly, it's less so now, but it's happened within the last few weeks in various countries where people refer to this horrible experience and why they don't want

to really try markets and what to do about it. So it was a bad thing. We were trying to deal with a very difficult problem on what we've been through this, and I can explain some of the talk this morning about the challenges.

But the key thing in these market designs that we're trying to work on was finding a good pricing mechanism, settlements, payments that would support the solution. And the lessons that we came back with from that experience were, I want to emphasize the first one here was the design principal about Integrate Market Design and System Operations. And that in particular focuses on the RTO and the spot market, and the real-time activities. And why it was important that those two things be carefully designed and integrated. And we spent a lot of time in this group talking about this over the years. So, it's not new.

We also will remember that the California crisis was not the only example trying out something that didn't work and then having to try something else. When Order 888 passed we had this discussion in that document about how to approach the question of market design and one way to go would be to have gone to the bid-based, security-constrained economic dispatch story. But that was viewed as too hard and too complicated, and we weren't sure what was going to go and we wanted to do something that was quote, "simple and quick." And we went the other way, which was the contract pass model. I won't go through every example, but even PJM which is the icon often cited around the world, in its first implementation didn't work and had to abandon it before they went to, as a last resort, the one market design that actually worked.

So, we've had a lot of experience with experimentation. And the center part of that story is about supply and demand, efficiency and locational crisis and all the things that are associated with it that you are all familiar with. And I put these pictures up just here to remind you all and also to refer to the discussion that took place around the California Blue Book in 1994.

And I actually provided testimony at the time in front of the California Public Commission about how an efficient bilateral market needs a pool, which was the terminology that was used at the time.

So this was not a new idea. It was, I suppose a new idea in the larger concern, but it certainly is not something that happened after the California Crisis. This is well before the California Crisis. And as a result of the hearings that took place around that Blue Book and when the California Public Utilities Commission was thinking about what to do, they came forward with their direction order instituting and about how to reform the markets. And they included something which I've often referred to it as the Ten Commandments. The Ten Commandments of the independent system operator. And what I, and the other nine of them are important, but I quoted for you here number seven. And basically what it does it goes through the picture you just saw before. So, it says we'll have an independent system operation that will run this economic dispatch. We'll get these locational prices and all that.

That was the direction from the California Public Utilities Commission, telling the market participants to come back with the details that filled in how we were actually going to do this, but here was the structure that should be adopted. And the principle debate at the time was about whether or not we should have an independent system operator that did all these things, or whether we should separate out something called the power exchange.

And I wrote at the time about the power exchange and the subtitle of the paper at the time was about the separation fallacy that you could attack, take this transmission operation and the power market and separate them. And I said at the time, the argument that the system operators should provide transmission services without any involvement in operating the dispatch and spot market is a seriously flawed idea. And included in that paper these three questions, and some of

this earlier discussion, which we've all seen before. I'll let you read them. You have them in the handout, but the basic message is I designed these three questions so that the obvious answer to each question was yes.

And so, should the system operator be allowed to offer an economic dispatch for some plants? And the critical words were some plants. It didn't have to be for everybody. Should the operator apply marginal cost prices? Well, the answer is if they didn't, then there was going to be something fundamentally inconsistent about the prices and what they were doing, and that was going to create problems. So, they should be using those. And then, finally, should everybody be allowed to participate and if you said yes, people could voluntarily, they wouldn't be required, they'd only be allowed to participate.

I think the natural answer to these three questions is yes. And if you say yes in answer to all three of these questions then the conversation is over because there's only one way to do it. And we know what that is. And so, what happened in California is that the parties got together, they produced a California memorandum of understanding in 1995, in which they ignored the principles laid out by the California Public Utilities Commission. And then created the separation of the power exchange and the system operator California ISO. And that was in a document that was filed. You can see all the different parties, including Speaker 4 [LAUGHTER], and then one of the responses and comment to it, to get to the point, the quote below it said, from the filing from these parties, it said I can also be read to suggest that the ISO should become the pool by taking schedules and so forth and so on. So, the answer's yeah, that's exactly what I would say. And then they said, that's exactly what we don't want to do. And we worked very, very hard to make sure that that didn't actually happen. And so, this was walking into this problem with our eyes open.

There's a wonderful paper that I recommended. If you go back, if you haven't read it or don't

remember it. It was then written by Steve Stoft, back in 1997 and the title of the power paper was, "What Should Power Marketers Want." When I first started to read it, I thought it was tongue in cheek, he was kidding. But he wasn't kidding. He was very serious and basically said if you look at this from a narrow economic perspective of power marketers, what would you want? And then I summarized what he said what they want. And basically what he said they should want is what they got.

Because this, under the memorandum of understanding, was a market design through the eyes of power marketers who were trying to find something that they could benefit from and everybody else could not. It's a very good paper and I think he was right on. Then subsequently I wrote about the market design and said, what's wrong with least cost? And so there's a series of other articles that are out there at the same time, but basically one of the things that happens when you separate the independent system operator from the power exchange, is you have to make sure that the system operator doesn't offer economic dispatch and doesn't seek the least cost solution. Because if the system operator does offer economic dispatch and seek the least cost solution then it will undermine the separate power exchange because everybody can use that as the spot market and that becomes the real spot market.

So, they had rules that were put in for the ISO, which said don't clear the market. That's absolutely important. So you have to leave valuable trades on the floor that you're not going to take advantage of because if you don't do that then our whole separation of these two things will collapse. And when I've discussed this particular with people in other countries and they go, you mean you had a rule the system operator had to use in inefficient solution? And I said, "Yup." That was our rule. And we had to do that.

The problems that evolved over this timeframe, as I said were going on in parallel in other places, and PJM in particular got in trouble in 1997, and

then reformed their model in 1998 and went to the full blown locational pricing story. The picture that you saw before that was shown this morning. And I put this in just as a reminder that it is possible to learn from your own mistakes. So, PJM made a mistake. They tried it out. They fixed the market design in 1998. They went on and moved forward with those kind of things. And the folks at FERC came up with Order 2000.

About that time, there was a lot of discussion going on, but what we also learned from the California experience is that you cannot learn from the mistakes of others. You have to make them yourself. [LAUGHTER] And so, what was going on while this PJM process was going on in the market design, which was better than California's, had failed, and then they reformed it. California was persisting in going on a new direction that caused all of these problems. I talked about the Blue Book and then we had pieces of legislation and then they started to implement in 1998. And then it started the sequence of amendments. I've listed several of them here. 18, 19, 23 and 24. And all of these tariff amendments were things that were coming back because the model wasn't working.

This disconnect between the ISO and the PX was creating all kinds of arbitrage opportunities that people could exploit. And they were trying to fix it and patch it and fix it. And finally, and the date here is very important. Amendment 24, the proposal for amendment came at the end of 1999. So, this is before 2000. And the response a week later that came out from the Federal Energy Regulatory Commission was, the problem facing California ISO is that the existing congesting management approach is fundamentally flawed—that's my emphasis added—and needs to be overhauled or replaced. So, that was where the quote came from in the title of this talk. And California, to its credit, when it got this order started a process which was called, Congestion Management Reform, CMR.

And after a little while, and I was a participant in that process, along with many others in this room,

this big gigantic stakeholder process was going and they discovered that congestion management was just the symptom of the problem and there was a fundamental design problem of the whole system. But they already had their webpage and the keywords, the letters for the webpage were CMR. So, they reclassified the project as Comprehensive Market Redesign. So, [LAUGHTER] you can't make these things up.

And that was going full-blown early on in 2000. And then we had the California meltdown in 2000 which was a combination of bad policy, bad luck and bad news. You're going to hear about this, the bankruptcies and so on. But basically my view of the California energy crisis is that the most important parts of the California energy crisis all happened before 2000. And most important, lessons learned along that way were about these issues about the market design. The high prices and all that was obviously a terrible problem.

But we don't want to forget that it wasn't that everything was working fine and then suddenly something went wrong. It was quite the opposite. So, after the crisis was over the Cal ISO started up this process of market redesign again and we finally had a quote that I extracted from here which basically said the separation fallacy was a problem, that having zonal pricing as opposed to locational pricing was a problem. We had to go to do something which is actually more like what they're doing now which is farther along. And there's several issues that came up over this period of time. Market power that we're going to hear more about. Market manipulation, by which I mean if you have two different entities which we're talking about the same thing, the same commodity, but using different prices like the PX and the ISO, then this creates arbitrage opportunities which you don't have to have market power, it can just be smart and then you can take advantage of it and exploit that. And we saw a lot of that taken out. And then we had patchwork regulations trying to respond and we'll hear more about.

But I do want to say that I think the market manipulation problems and the regulation problems were quite serious. Market power problem I think is more controversial. And I'm going to just summarize by citing a study that was done by the Federal Energy Regulatory Commission. This will take longer to go into all the details, but the essence of it is that it's really hard to identify the exercise of market power, without having a lot of information that's in the hands of very few people, like the system operator. And there were lots of studies done which were all indirect inferences.

But there were importantly some direct attempts to do this by looking at individual plants, and the California Public Utilities Commission did a study in which they were analyzing plants during critical hours and how much did they withhold. And the federal regulators staff came and FERC staff came and looked at this, and then the final paragraph tells you the basic message. In the narrow context of the staff's review of the report, staff concludes that the CPUC significantly overstated the degree to which generators held power out of the market in those days when firm service was interrupted, and so on. And then, of course, this was politically incorrect, so they had to add the other sentences which were, the Commission has not concluded the investigation of whether physical and economic withholding occurred in California in other hours and so on.

But it turns out that the only place we've actually seen the evidence addressed is in these particular hours. You can go through the details of this chart about what was going on, but these were things where they had environmental restrictions and the ISO wouldn't let them use it, or there were transmission constraints and they wouldn't let them use the plants, or so forth. So essentially the gap analysis and the withholding all disappeared once you started to look at the actual details of operation. And now, at the bottom and this is me speaking, this was an important moment and I say in bold here, with respect to the California crisis, there are no confirmed cases of withholding the exercise market power and

manipulating prices. This of course is not the conventional wisdom, but it is certainly something I'd be happy to talk about later.

Moderator: Also truth.

Speaker 1: So, what's the big lesson? The big lesson is: do what we're doing in the wholesale market design, which has now taken over all of the organized markets in the United States and importantly, as everyone knows, it's growing rapidly and organically out West because of the Western Energy Imbalanced Market which is also based on putting the economic dispatch locational pricings and all the other things in the market design that actually works.

So, it was a very expensive lesson to learn in various parts of the country, especially expensive. The problems, the special problems of California and the high prices and the crisis were really bad, but they worked separate from, and we shouldn't forget about the implications for, market design. Thank you.

Speaker 2.

Right. There we go. For those of you who don't know me, I was a Commissioner at FERC from 1993 until 2003. Over 10-1/2 years. Calculating once, I voted on 28,000 orders while I was there. I was there for the implementation of Order 636. The opening of the markets in Order 888. The promulgation of Order 2000 that encouraged the formation of our RTOs. The California energy crisis and the ill-fated standard market design, NOPR, which was issued by FERC in 2002. Which is still a great idea. There's just a lack of political courage to do it now. This was a very painful experience for all of us at FERC. It was very painful for me because I was departing from the majority in a lot of votes and didn't have other commissioners with me. But my staff runs in, in May of 2000 and says crisis in wholesale markets in California have just spiked from about \$30 a megawatt hour, 35 up to 280, 290. And we were off to the races. Chaos ensued. Prices stayed high. It was an absolute economic meltdown for the next 13 months.

So, what happened? Wholesale prices soared across the entire West. This wasn't simply a California price problem. This was a Western interconnection wide problem. As Speaker 1 has pointed out, we had an extremely bad market structure and market design, and I'll talk a little more about that. There were blackouts, business disruptions in California, in the West through this 13-month period. There was some gas and electricity market manipulation. This was a big problem. FERC in California were slow to impose effective remedies. FERC pointed fingers at California and California pointed fingers at FERC.

There was a lot of that going on during the crisis. It was an absolute fiasco and almost completely shut down the movement to electricity markets in the United States. Valuable lessons were learned. AB189 passed unanimously by the California General Assembly. I believe it was 1996, under the plan retail rates were cut 10 percent and frozen until stranded costs were recovered by the investor owned utilities. It created the separate power exchange in ISO. Power exchange ran day-ahead and hour-ahead markets. I think there were other markets too, but I remember those. ISO was stuck with the balanced supply and demand schedules from the power exchange that were handed to the ISO.

As Speaker 1 points out there was no least-cost dispatch. There were three big congestion zones that were used. There were out-of-market bilateral purchases at the last minute to avoid shortages. This is important. The ISOs were acquired to use the spot market for all of their supply. They still had about 17,000 megawatts of generation left, QF and hydro. I think a nuclear unit. So, they had to sell all that into the spot markets and buy all their supply out of the spot markets. There was some hedging around the markets, but not very much. It was strongly discouraged believe it or not.

So, they couldn't implement any of this without coming to FERC of course. They made 203 filings for the transfer of control of various assets.

205 filings to establish the ISO and power exchange, and the protocols for the markets. The entire California congressional delegation supported this. A letter came to all of us Commissioners, Speaker 4 has it. The letter. There were 47 members I think at the time.

Moderator: 53.

Speaker 2: 53. Thank you for that. [LAUGHTER] And it basically said FERC, don't touch a hair on its head. This is a perfect plan. This is what we want. And we all supported markets and this is what the seventh-largest economy in the world wanted. Staff came to us, Dick O'Neill and some others, and said, "I don't know whether this is going to work or not." SDG&E filed a proposal at FERC to merge the ISO and power exchange year's locational marginal pricing. Withdrew the proposal under severe California political pressure, during the middle of the hearing that we were having. The President of SDG&E was Tom Page. Went out for a break or for lunch, came back and said, "I'm sorry. I withdraw our proposal." [LAUGHTER] That's basically what happened.

So, what did we do? In a series of votes, we approved the bad market design, bad market structure. In my 28,000 votes, this is the one or two that I really regret making. I was supportive of markets, but I think we all knew better to tell you the truth about market structure and design. I don't speak for anybody else. I speak for me. I wish I hadn't caved to California pressure.

Spring and summer of 2000, and the next few slides I'm going to show you a series of FERC ineffectual orders that may have actually added fuel to the flames. Didn't do much over the next 13 months. It was a desperate attempt to stop a crisis that was unfolding in the middle of a bad market structure, bad market design. Chaos with California shouting at us constantly, saying "You federalized the market, FERC, you've got to fix it." And we shouted to California, "This is what you wanted. You fix it." Irresponsible on both sides, if you want to know the truth.

Prices were low through April of 2000, often around 30 to \$40 a megawatt hour. We all said, "Man, this is wonderful." Dramatic price spikes in May. Up 500 percent, 1000 percent, spiking significantly higher. Frequent system emergencies, financial distress. If you're paying \$250, \$280 a megawatt hour at wholesale and you're reselling at about, I think it was about \$60, Moderator, at retail.

Moderator: 60, 65.

Speaker 2: You know that trap costs which were supposed to be unconstitutional, built up quite quickly. The Supreme Court says you got to flow through wholesale costs in retail rates. Not in California. That did not happen for about 11 months. I'm not blaming California for everything, but—

Moderator: You can.

Speaker 2: I know you think I can, but I want to think FERC could have done better too. So, SDG&E files a complaint and says help. This is a disaster. They want \$250 price cap on the PX and ISO real time markets, not a severe price cap. They basically said, "Help." This is the way prices spiked. You can see it going up in April and continuing to rise. This is, you can see it bumping along in 1998 and 1999.

Well, I can tell you at FERC, we didn't know what the hell was happening, but we knew it wasn't what we intended. I'll tell you that. FERC order in August, 2000, nope, we're not going to cap prices. We don't have enough evidence. We're going to open a 206 investigation. I dissented. I said, "No. This is an absolute disaster. We got to do something. Put a cap in place, we'll figure it out." Wholesale prices continued to soar. Buy high, sell low. The utilities were becoming quickly insolvent. CPUC was not willing to raise retail rates. They were still frozen. And a lot of finger pointing and blame. November, 2000 order says there's a whole bunch of remedies we would consider.

Let's think about them. December, 2000 order: set pay a bit above \$150 breakpoint. We said, "Look, we want independent boards for the PX and ISO." So, we took control of the ISO and Power Exchange boards. DC Circuit later told us, "You can't do that, FERC. This is a public utility." We recommended a \$74 price for long term contracts, imposed a penalty charge for the IOUs under scheduling of load, and refused to impose a West-wide price cap which actually we should have done. Early 2000. Multiple FERC orders allowing prices in the 300 to 400 megawatt hour range.

So, no surprise the wholesale prices continued to soar in early 2001. Utilities weren't creditworthy. They were defaults. They weren't paying the independent power supplier. Some suppliers withdrew supply from the market. Hard to blame them for doing that. There were liability issues. Rolling blackouts. DOE stepped in and required public utilities to sell. It may have been broader than that. It may have been all utilities to sell. But no, I think it was just the public utilities.

Moderator: I think it was everybody.

Speaker 2: It was everybody? OK. It was everybody. The California Department of Water Resources had to step in because there was no solvent counterparty that was creditworthy. So, they bought power long-term. Some of it up to 20 years and the average price was \$245 a megawatt hour, for that power. In March, CPUC finally authorized a retail rate hike. PG&E declared bankruptcy in April of 2001. I believe it was the largest utility in the country at the time. Two new commissioners came onboard in April. Pat Wood and Nora Brownell. And we put our heads together and said, "Hey, enough is enough here. We've got to do something more forceful." Order in April, mitigated prices, mitigated mids down to the marginal cost of each unit. When reserves were 7.5% or less, which was virtually all the time. Established a West-wide investigation saying, "This is a West-wide problem. The market is the West. And we're going to look at it West-wide."

That had a calming influence. Forceful Order in June, after 13 months. West-wide price cap on all bid-based and all bilateral markets during all hours. Which we should have done months earlier. Must offer requirements, West-wide. Dramatic cooling off of the market. Precipitous drop in wholesale prices. The crisis subsided. That's the way it looked. This is a California Energy Commission data. Causes of crisis. This was a very hot summer. It was a low hydro year. There wasn't a lot of snowpack. California over-relied on about 25% of its power source from the Pacific Northwest hydro. There wasn't a lot of it. A new generation hadn't kept pace with the sharp demand increases. It was hard to build new generation in California. I believe there was a big nuke offline during the crisis. Is that right? At one point.

Moderator: Briefly.

Speaker 2: Maybe not during the—

Moderator: In January 2001, I was called and told Diablo Canyon was on because there was kelp in it. Killer kelp.

Speaker 2: OK, and maybe I have that wrong. Unusually hot summer. Anyway, there was a significant supply/demand imbalance that fell on a very poorly designed market. Serious market structure and design flaws. Natural gas prices soared. Sorry about that. Natural gas fires units that were setting the market, clearing price. It was a single clearing price model. Everybody got the market clearing price. So, high natural gas prices. Of course, increased prices in the wholesale market. There was some bad behavior. FERC and California policy-makers were in stalemate. Slow to order meaningful solutions. Finger pointing. I've emphasized that. I think that was a horrible problem.

Here is the significant price separation in gas prices. The lower line is Henry Hub. And Henry Hub prices increased too, but this is California's spot gas prices, Southern California during the crisis. These generators were relying on natural

gas. Market flaws. Separation of PX and ISO. FERC knew this was bad. Poor congestion management. No LMP. Market boundaries were too small. The market should have been the entire Western interconnection. Period. It's about 60% of the power got sent to California. This was a Western-interconnection-wide problem that needed the Western-interconnection-wide solution. And frankly, a Western-interconnection-wide organized market. Vague prohibitions on gaming and anomalous behavior in the tariff. FERC had weak penalty authority at the time. I think it was about \$5,000 a day for, if somebody was caught manipulating the market. Now, it's of course a million. Retail electricity rate freeze. Buy high, sell low is a disaster. Sequential closing of the wholesale markets incited delay in offering supply to fetch the highest price in the market. An over-reliance on the spot markets. There were restrictions on long-term contracting imposed by California, which made it very, very difficult to hedge around the spot markets.

Changes after the crisis. The AMR to you, a merger of the ISO and PX functions. Bid-based, security-constrained economic dispatch with LMP was imposed. More sophisticated tariff and market behavior rules. Congress gave FERC a million dollars a day in penalty authority for violation. The same authority that the SEC has in 2005. Consequences. Power cost 7.5 billion for California in 1999, 30 billion in the year 2,000. Severe economic disruptions. Gray Davis was recalled. Electricity competition unfairly discredited.

The front page news around the world was electricity markets are disastrous. Stay away. Basically. We still feel the impact of that. That's not true. A bad market will yield a bad result. That's the truth. Pat Wood, Nora Brownell and I put our heads together and said never again. We know what to do. We're going to PJM the whole country. And we issued the proposed standard market design NOPR. Those who opposed said it was a Soviet planning model, a federal power

grab. We got our heads handed to us. It was still a great idea. It's a great idea now.

Moderator: Wasn't it the Russians'?

Speaker 2: [LAUGHTER] Yes, it's the Russians'. Right. [OVERLAPPING VOICES] Pardon me?

Moderator: It was the Ukrainians.

Speaker 2: Oh, it was the Ukrainians. Anyway, it was a good idea then. It's a good idea now. There's no political will to do it. All right. The cleanup lasted for years. The Moderator and I were just talking about that.

I just read a 9th Circuit Court of Appeals decision in 2016, on some of the behavior in California. Lessons learned. Bad structure, bad design leads to disastrous outcome. Electricity and gas markets are joined at the hip. We know this. But this was vividly displayed in California. Contracting around the spot markets is absolutely needed. Retail rates have to reflect wholesale prices. We need demand response for a well-structured wholesale market.

And this is important. FERC should not blindly defer to state decisions. FERC has a job to do and should do it, both when they know what's right and take responsibility for it. And actually market boundaries are intrastate. And regional, not state by state. FERC has to insist on good market structure. Proactively monitor. Have clear rules about market behavior. Investigate and penalize bad behavior. Act quickly and forcefully to shut down a chaotic market. And finger pointing between FERC and the states doesn't work. Thank you. Pardon me?

Moderator: You said you regretted two votes on two orders. [UNINTELLIGIBLE] for your markets, but I'd like to know what others.

Speaker 2: Oh, that's a secret. [LAUGHTER]

Moderator: Can you waive executive privilege?

Speaker 2: I told Pat Wood I'm not telling anybody else.

Moderator: We went a couple of rounds without clarifying questions. We'll have one now. How about it?

Question: Speaker 1, do you or any of the panel remember what the exact reserves were on the system? Either what they were planned for, or what they actually were when all of this happened?

Speaker 1: I don't.

Speaker 2: I do. 7%.

Moderator: Unless it was zero.

Speaker 2: We didn't have planning measures back then. We developed that after the fact. So, it was the basic NERC standards which I believe was 7%.

Speaker 1: OK. Well, those are just operating reserves and I think your question probably was more of resourcing adequacy. And I've got a little bit different view than, at least nuance than I think I've heard so far on that.

Moderator: Have at it. You're up.

Question: I'm up? OK. Hold on. Are we OK? Speaker 1 or anyone on the panel, could you just clarify the payers bid order that you all issued? What was the impact of that going forward, the thinking behind that and what did that result in? Because I had forgotten that specific interim order.

Speaker 2: Yeah, it was payers bid.

Questioner: Maybe about 150 or something like that?

Speaker 2: About 150. It was intended to look for bids below 150 or below. This set the market clearing price. Pay a bid above 150 won't set the market clearing price. The problem was natural

gas prices were so high at that point, the right point was about \$150 bucks. And so that didn't work so well. But it was intended to calm the market. It didn't work at all.

Moderator: All right, let's keep going.

Speaker 3.

OK, so let me tell you first of all what my vantage point was in the company. I worked for Southern California Edison at the time. And I was Director of Regulatory Policies. So, I was not at the very top of the company, by any means. If there were a half dozen people that got together to strategize I probably wouldn't be in the room, but if there were a dozen people that got together to strategize, I almost surely would be in that room.

And the management at that point had a pretty well socialized process of managing. And so, everybody pretty much knew what the strategies were and what was going on. So, I feel like I'm pretty well informed. I don't have any continuing stake in Edison. I'm acculturated. I'm sure Speaker 4 will agree with this. I'm 20 years of acculturation into the utility industry and so, I'm going to be inclined to have kneejerk reactions to defend the decisions made by the company up to a point. I could tell you probably one story out of school and I'll do it a little bit. There's nothing terribly surprising about it.

So, I'd been told I have about 12 to 15 minutes to talk and I don't want to repeat what's already been said and I agree with 90 or 95 percent of what's been said. So, I want to focus on causes and I want to focus on some of the subtleties that may not be so apparent and maybe where I dissent a little bit from statements that have been made before, I'll throw those in as well.

So, when you think about causality, I mean causality is a flaky, squirrely notion to get your hands around, especially when you've gotten multiple factors contributing to things. It's like having a traffic accident. A complex traffic accident and I'll argue about well, what caused it? Well, there may have been four or five different

causes. And preconditions were responsible for it, but I tend to put a lot of weight in this comparative negligence investigation on who had the last best chance to avoid the accident. And as far as I'm concerned it was the California government that did. And that they failed miserably.

It wasn't that there wasn't a lot of other contributors and I have a few things to say about FERC as well. As well as everybody, as well as other market actors. But just to let you know where I'm coming from and I'll try to expand on that. It's the last best chance to avoid the catastrophe.

I will plug myself and say you've all got copies of this article that I published in 2002, in *Electricity Journal* and I was impressed when I reread the article on the airplane coming out here. [LAUGHTER] I think it's one of the better short things written on the crisis. I mean there's books written about the crisis. So, there's plenty of things that you can read. So, I'm going to maybe go through two slides, but I don't want to go through all my slides because we've already talked about a lot here. Let me just kind of get to, yeah got it. I think there's general agreement about the kinetics of the accident. This happened and this happened, and this happened and oops. All sorts of bad things happened.

So, we start off with market fundamentals, a tightening of the market. We probably could argue about exactly how tight it was. I think it tends to be a little bit over emphasized, but it's certainly part of my story that the reserve margins certainly got thin by all means. And they confronted a retail structure that had mandatory divestiture of a great amount of power plants. And mandatory buy and sell from the spot market by the utilities. This was one of the really big mistakes that was made in terms of market structure.

So, utilities were sitting there with these huge short positions that had to be filled on a day-ahead basis, basically, and in real time. And they didn't

have the generation to satisfy their needs. And then you combine that, then just go on from there and say the fact that as markets tightened and you had such a great need for purchasing in the short term, I think you had suppliers who got market power.

And there were lots of other things that are happening here and there's lots of debates about just what kind of contribution for manipulation, what kind of contribution to market rules, et cetera, but I believe based on some modeling that I did and I actually got published in another *Electricity Journal* around this time. We did some simple oligopolistic stuff that just, when you have this few players and you've got such large demands that they need to satisfy, and you've got fairly tight margins then it's very easy to tacitly collude and through Cournot oligopoly tacit collusions, simply charge much higher prices. And I think these markets are subject to a natural amount of market powers, especially when the margins get tight.

And the lesson is protect yourself from that and protect yourself through long-term hedging. So, we had these incredibly high wholesale prices. And then we had the retail rate freeze that didn't let utilities flow that through and put the entire burden on the utility balance sheet and solvency and cause bankruptcies, et cetera, and all sorts of chaos. And of course, the real problem ultimately in terms of the last, best chance to avoid this catastrophe was with California government, not asserting leadership, getting people together and reaching a settlement.

So, in short, you had these short-sided market structuring rules. You had adverse market conditions. You had inefficient market rules and all combined with manipulation and market power. And you also had just simply dithering by the various regulators and ultimately everything blew up. Blew up on January 17th, when utilities went insolvent.

As I said I don't want to repeat everything that's been said, but I do want to comment on a few

things. And one thing is the issue which I think is a little bit of a phony issue. Not that it's a nonexistent issue by any means. I just think it's overemphasized for political reasons by some people who want to solve a notion. That it was all caused by California NIMBYism.

Now I'm not going to tell you that there isn't NIMBYism in California. Come on. But there was generation shortage throughout the West in terms of building during the decade before the disaster. There was investment uncertainty throughout California starting in 1993 because nobody knew what the structure of the new market was going to be. It was announced that there would be a new structure, but it wasn't put in place. And also, there was this tremendous reliance, I think over-reliance, on what people perceived to be working in the U.K.

And that led to the perception that an energy market, energy-only market is perfectly fine. Energy prices will go high, people will get the signal to build more capacity, they'll build more capacity and the high market prices will subside and be quelled. And I think that what we've experienced, if anything it continues to be an elusive problem today, is the whole resource adequacy issue and how we deal with resource adequacy.

So, there's still those things festering around. Natural gas prices were brought up. I cannot over-emphasize how that really, really exacerbated, complicated the problem. Everybody believed in the summer of 2000, well, this is going to be a summer 2000 problem. Then it's going to subside because the loads are going to come down, and then it will be a problem in the summer of 2001. And so, we'll have this decent interval in which to try to solve things.

That just didn't end up being the case for a number of reasons, but I think in no large part, or no small part, due to the run up in the gas prices. That happened in November and December. They just made solving the problem just much more critical, in terms of doing it quickly, and

much more difficult to deal with. You had the retailers returning to their customers to the utilities, driving up the utilities' net short position. You had Enron turning back its customers to the utilities, basically saying, "I'd rather take this power and sell it in the wholesale market than sell it under the contract that I got with this lousy customer. Sue me in court." And they did get sued in court for doing that.

You did ultimately have lots of reliability problems that we all remember, but which we might forget. Those things happened for the most part after insolvency was declared by the utilities. And what was happening there was that generators were definitely withholding at that point because they knew that they did not want their reward. They were expecting cash for their power. They didn't want a seat at the bankruptcy table in order to recover the cost of power that they had sold to utilities.

So, we had 32 days straight of Stage 3 emergencies. Rolling blackouts, not generally, but all the interruptible customers didn't think they'd signed up for so many interruptions. And so that was a big problem in January and February. But those were January, February problems. There were a few reliability problems in the summer of 2000. But when you recall what happened there's a tendency I think to take all those rolling blackouts that we had in January and February of 2001, and think, "Hey, a lot of those things happened in 2000." That's not the case. They didn't.

There was also the fact, and this is a bit of an omission. I personally tried to sell the WEPEX process, which was the process in 1996 and '97 that was trying to put together the structure of the market. I went in and tried to sell them. I remember going into the meeting chaired by David Freeman in a hotel out in the airport. They had all the WEPEX people, Mike Florio, et cetera, et cetera, wearing buttons that said Divest Now.

Basically, I tried to sell them on vesting contracts that the utilities would have from the generation that they were divesting for at least five, six, seven years to kind of smooth out the process. If that had been done this wouldn't have happened. But that was absolutely rejected. I was thrown out of the room. I mean it was incredible. There was just nobody. There was no appetite for that.

Let me say a few things about FERC. I really don't blame much on FERC, especially of terms of comparative negligence in this accident. And certainly not compared to California. FERC had put market-based rates in place in what, 1987, '88, '89 under the old HESI regime. But there was never any standard that I recall, for exactly what was a reasonable rate.

And so, FERC was definitely recognized because politically it couldn't recognize, couldn't possibly not recognize that the high prices in the summer of 2000 were, yes, they were unjust and unreasonable. But the only thing they had to apply was the pornography standard and it was absolutely clear. Those are unjust and unreasonable, but what the dividing line should be between just and reasonable and not just and reasonable was not something that they had ever put a sharp focus on. Because they never had to.

So, I don't blame them. I don't blame them from an institutional standpoint because I think these are the kind of fine point issues that need to be driven by specific cases for the same reason that the Supreme Court does not hear arguments about hypothetical law suits. Bring me a real lawsuit and I'll tell you exactly what the dividing lines are. And I think FERC was faced with that same thing. So ultimately, they were faced and we will discuss here and disagree as to what are the contributions of market power. Meaning either economic or non-economic, or physical withholding.

Market manipulation of the type practiced by Enron, but not just that because they were actually in many cases violating the tariff rules, which was clearly illegal and they got punished

for. But they were also blamed for gaming the rules. Well, what the hell does that mean? Gaming the rules. I mean, I set rules in place.

When the IRS puts rules in place and then we have to figure out well, what's tax avoidance versus legal tax avoidance, versus tax fraud? Well, you can't put rules in place and then expect that people will please play nice. Play nice with these rules. I mean these guys are all trying to make money. And so, it's difficult to put a fine point on these, on these gaming issues. And I think the bigger thing in my mind is that the Federal Power Act just says, prices have to be just and reasonable. It doesn't say, and only prices that mimic a perfectly competitive market are just and reasonable. It doesn't say anything like that.

Economists might wish that it said something like that, but it just is a bunch of words and it's not exactly clear what that dividing line is. And I think that when, what really is difficult philosophically, and it will come up many, many times again, in terms of lessons learned, is what's the dividing line between X, improper exercise and market power, and just scarcity pricing? Economic grants. All I'm earning is economic grants. I heard plenty of this is just economic grants that we're earning. We're not behaving illegally here. We're not withholding.

How do you discern and put in place mechanisms that will discern those nuances? OK, so let me get on and talk about why did California dither? Well, first of all California dithered because the governor was a career ditherer. [LAUGHTER] And I take that from comments that I've heard from knowledgeable political people. He built his career on temporizing problems. I've got a lot of sympathy for, I think the first thing you ought to do is not respond to emails too quickly. [LAUGHTER] And you temporize problems, but there's a limit to that. I mean clearly this was a huge problem.

They were warned as early as September by Standard and Poor's publicly that they were headed for insolvency by early 2001, if they

didn't do something. But what did Davis do? He kept his own counsel. He said, "I'm not going to talk to anybody because you guys are all contaminated. I'm not going to talk to the utilities, I'm not going to talk to generators. I'm going to go sit in my office and figure out what the, how to solve the problem." I'm not sure what he came up with, but he wasn't talking to anybody. He should have been talking to everybody.

Then you had Commissioner Lynch at the PUC, who I think was outwardly hostile towards the utilities. Naturally, we're all paranoid. I mean being a utility employee that's always the case. But I really do believe that she was getting bad advice and bad visceral reaction that, "So what if the utilities go bankrupt? We're going to, somebody's got to pay for this thing and utilities shareholders ought to pay for it. We'll just take their equity. We'll pay for the power with their equity and they'll go and solve and no problem. We'll just change all the names of the stock certificates and that will take a night. And then we'll go along our merry way without any bumps."

I think there was a real lack of understanding as to what the real impact of bankruptcy is as people tried to avoid getting stuck at the bankruptcy table for months and months and months, trying to get their money. And that's what played out. And then you've got the issue, and I think this is significant. When I think back at it and I also talk about it in my *Electricity Journal* paper. There was the thought that this was all going to subside after the summer of 2000 and we'd have this nice window of opportunity.

Now, in that window of opportunity the Gray Davis plan was, "First of all, FERC is going to solve the problem, in some sense. And drive the prices down. And then we, California, will go out and enter into long term contracts at reasonable prices, but we're not going to go out there and contract with the generators, while these prices are out of control and the only prices on the table are high prices. So, we're just going to sit here

and dither and point our finger at the F-E-R-C, until they do something.” And I think that’s one of the dynamics that really got into us dithering and pointing fingers, et cetera, et cetera.

Then you had that window close. It wasn’t just a December of 2000 problem. It was a problem that festered and festered rather quickly. And then, finally, this is my last point. I think that another reason why the California parties could not get themselves together in the settlement was there was just a lot of bad blood and poisonous atmosphere. And everybody is kind of pointing fingers: “This is not my problem. This is your problem.”

And not to use a sexist term, but their allusion here, that this was a game of Old Maid. Who was going to get stuck with the Old Maid card at the end of the day? Not me. Not my fault. You’re the one that deserves to have it. And it comes down, a great part of it comes down to the interpretation of what was the meaning of the retail rate freeze? The retail rate freeze was put in place at about \$65 a megawatt hour. And it contained headroom in which the utilities assuming normal operation of the wholesale market would probably be able to recover their stranded costs within five years. But we’ll put them at some risk and if the wholesale prices go up and squeeze the headroom then that’s the risk they’re taking. And the utilities signed up for that risk.

Well, what the utilities didn’t think they were signing up for was the risk of having stranded costs added, too, if the wholesale price went so high that it actually exceeded the rate freeze and they had to eat it. In other words, their interpretation was OK, then that access should go into a balancing account that will eventually will be a regulatory asset, a firm regulatory asset, we’ll be able to recover that eventually.

And originally, the accounting for this was set-up and approved by the PUC that had that view. That the retail rate freeze was kind of a one-way deal. But then the PUC later, from advocacy from

consumer advocates, totally changed that accounting, and basically provided for the, essentially accrued additional stranded cost. And the utilities cried foul.

I wasn’t close enough to this whole process to have an independent objective opinion as to what the utilities really thought, but I do know what they said. And what they said was really consistent with ultimately the filed rate doctrine. That is when the price goes above you can’t tell them they can’t recover that. And so, the federal courts ultimately said, “No, you can’t let that whole, high wholesale price establish more stranded costs. That just isn’t the way, that’s not something we’re going to approve.”

And that’s the way it ultimately turned out, but in the meantime we had to go through all this hell of insolvency, bankruptcy, getting the California government in, getting all sorts of money from the California government, et cetera. We just kind of transferred the problem from the utilities to the California government. There’s a lot of poetic justice in that at the time. I remember that undoubtedly wasn’t Speaker 4’s perspective, but from a utility employee advantage, that perspective is OK. You guys screwed up by not solving this. Now you got it. And they just proceeded to get all sorts of stranded costs essentially placed upon them. So, that’s it. That’s all I’m going to say.

Moderator: So, you’ll have some clarifying comments I’m sure from great people, including me. [LAUGHTER] But let’s listen to Speaker 4 this time first.

Speaker 4.

OK. I’m going to get set up here. Well, I wasn’t there and I paid my own way so I have no idea why HEPG invited me to this, but it’s been very interesting to find out what happened in California 20 years ago.

I’m with the Independent Energy Producers Association. I represent the wholesale electric generators renewables as well as natural gas and

now storage. And I was front and center in all this back in the days that when we first did all this, by the way, there were QFs. There were no AWG. AWGs had just begun to get into the market and whatever else.

So, I thought it would be useful to kind of tell you how I spent my summer vacation in 2000. In the summer of 2000, ISO California during this period of time had a 26-member stakeholder board. I had been assigned the task of being the chair of that board and, as well, I was talking to senior utility people in Florida once and they were going, "Well, why in the world did they appoint you, the leader of the QFs as the head? How did the IOU let that happen?" And I said, "Well, because each of them trust me more than they trust each other," which the entire group laughed except, until their CEO kind of went, "Ahem," and they all started staring straight ahead. But I ended up being the chair from, basically, the inception of the ISO through January of 2001. And it was a really exciting time and for a while it actually did work.

Everybody kind of forgets that, but it did work. I was involved in getting a Harvard education seminar when Speaker 1 and a number of others would come out to California in the mid-'90s to talk about what the perfect market structure was and there was significant discussions about all of this. And so, he was kind enough to point out the fact that I did sign a thing called a Memorandum of Understanding in which I'll get to in a minute.

But the reason I think this is all relevant has nothing to do with "Gee, this was an interesting time and Steve Peace had a funny movie." But it kind of makes sure this doesn't happen again, because none of this was done with malintent. People didn't deliberately screw things up because they thought it would be an interesting experiment. This whole thing was driven by some very important expectations about how the world ought to work. And obviously things went awry and the real story here is what do you do when stuff starts falling apart?

We talked this morning about the future world which is going to be 100% green. I don't know how you do that with variations in weather and everything else. We're working very hard on this issue in California. But I see danger in not learning from the past. And this gives us an opportunity, I think as all three of my colleagues have pointed out here, if you have a bad market structure, expect bad results. And if you have bad results, be prepared to act quickly.

A lot of this you heard already. I'm not going into market design flaws. My colleagues have done a good job there. The hydro conditions, gas disruptions always get forgotten in this discussion and it's very important to remember. And the main thing I want to point to is the lag in prompt regulatory and political action. So, expectations that California restructured. So, why in the world do we do this in the first place? Peace is hell. In 1990, early '90s, the Cold War was over. It's hard to believe that now. And recession impacted the California economy. California economy was heavily based upon aerospace and defense. There is three different bases that closed in my town of Sacramento.

Governor Wilson, who had just been elected, ordered his entities to figure out how to revitalize the economy. The PUC in 1993, investigates alternatives, potential alternatives. That was The Yellow Book. A great read. I still have it. And then Speaker 1 talked a little bit about the PUC wrote another book called The Blue Book, in which you decided that it was going to go forward with direct access model. And that there was a pool related to that.

At that time Commissioner Fesler who was in love with all things British was infatuated about the liberalization in the U.K. And that was the focus. The commercial industrial customers wanted direct access and a date certain. That was the key thing they wanted. There was a whole lot of cheap hydro in the Northwest at that point in time. And in order to keep industry going in California they wanted access to it. They didn't want to pool. They didn't want any help. They

just wanted to go get it. Utilities wanted the ability to cover stranded costs.

This is not anything surprising. And there was a strong preference for the California restructuring. It was going to market, not regulatory decisions for future investments. Now, in California at this point in time, we went through a buildout of a number of nuclear power plants which followed the traditional pattern of coming in late and over budget. And they were expensive. And we didn't want to do that, so we backfilled stuff with qualified facilities. Both of these by the way are based on a \$100 a barrel oil, which obviously did not happen.

So, that was kind of a decision that California was trying to learn from. And so, as a result of that, we'll get to this in a minute, of why people don't like contracts. Market efficiency would lead to lower prices and innovation was the expectation. Now, the letter. And I brought this because everybody goes why in the world was Speaker 3 asleep at the switch?

Moderator: Everybody wants to know that.

Speaker 4: Yeah. And, this is a little out of order, but in 1996, 1995 we did the Memorandum of Understanding between, that you saw earlier, between Edison, two different manufacturer groups, IEP, my group was there, basically to protect our QF interest. I was glad, I spent the entire summer of 1995 helping solve stranded costs issues which had nothing to do with me, but we needed to get the job done.

But at any rate, so we were very proud of the Bill 1890 and so, this letter, so this was signed by the entire California Delegation for the purposes of protecting the restructuring construct from the Federal intrusion, those people at FERC.

And I'm just going to read a couple quick things here: "This historic legislation AB 1890 was a result of months of careful study, thoughtful consideration, intensive deliberation by a broad based coalition of stakeholders. The new law

provides customer choice. This will ensure that all electricity companies, both large and small benefit from rate reductions resulting from competition. It will prove the reliability service advances the state's environmental concerns, ensures the financial soundness." I already lost myself. "The system of the utilities and, in short, it will provide tremendous benefits to the citizens of the State as well as those doing business in California. We are justifiably proud that California, which represents the seventh largest economy in the world, is again in the vanguard of this unfolding issue. We believe that the decisions made in California in utility restructuring and competition are the right ones for the state, and must have the opportunity to be fully implemented."

This, in case you missed the subtlety, is basically, "Hands off, federal government and FERC." So, that was there. So, when you hear my colleagues in California suggest that somehow they were just asleep at the switch, there's more to that story than that. All right. I'm not going to go through all this other than to basically say that California legislature voted unanimously supporting electric restructuring. The whole thing about sausage and the law, this was the world's largest sausage. Everybody got something out of this and I mean everybody.

So, there was a lot of things that were put into it. The 10% rate reduction which I think we may still be paying for, I don't know, was sort of a bait and switch that basically say we were obediently lowering your rates. But at any rate, that was there. Steve Peace actually gets a bad rap. Steve Peace was the chair of the Senate Energy Committee. He held up all the legislation to have a mega deal. So, Edison had a thing, something on basically their [UNINTELLIGIBLE] plant and the manufacturers who were driving a lot of this wanted direct access and he held up everything except for these long hearings.

There was literally 100 hours of deliberation on this in terms of formal, informal meetings. I think he got that job done and his problem was he never

let go and kept talking. This may remind you of someone who is currently still talking, but at some point in time you leave whatever you've done and move onto other things. He didn't.

And in full disclosure, my wife actually was his chief of staff at the time and was responsible for putting words on paper when they would come out of these hearings. So, at any rate, we know a little bit about this. So, the market structure as you've seen, basically we had the power exchange. You've already seen all that. There was a date certain.

The only thing I want to put here, the ISO was designed basically to operate as an air traffic controller, as it was suggested earlier. And the CPUC required the ISO used to vest, 50% of their fossil generation. Now the key on this is that they sold pretty much all of it because they were getting good prices for it. People forget the fact that people were paying three to four times book value for some of those properties and we all assumed at one point in time they were going to be stranded assets. Well, they weren't. OK. They basically generated a lot of capital which my utility colleagues put in there, in affiliated companies and off they went elsewhere to invest that money. And that all worked.

But anyway, the point is that they did basically run, they'd sell off all those projects, fossil generation and there was a plan to sell off their hydro as well, and there was always a question what to do with nuclear. So, at any rate the squeeze which we talked about earlier, basically you saw prices move up in the gas market, in the spring of 2000. I had a colleague of mine that was in the gas business and he was telling me he wasn't sure what was going on, but it was getting interesting. I guess the event occurred on May 10.

Now I can honestly tell you I was in Sweden, so I have no idea how any of this happened, but I got back and all hell had broken, I didn't do it. I was in Sweden and I probably should have stayed there. But at any rate, came home and again, I

was assured the ISO, and literally a day after I arrived we have to have a debate on price caps because that's all we started talking about. So, you've already seen the issue.

The other important part and there's a big spike on Speaker 3's slide that occurs. It's not July '98. It's July 2000. There was a tragic event on the El Paso Pipeline. A family had camped on top of where the pipeline went through and blew up the camp. And shut off a major supply of gas to California. So, it just got worse and worse and worse. An internal gas leak in California was running hard. It was an old fleet. A number of them ran out of air quality credits. You've already had the conversation about accusations and supply withholding.

But I mean the point is that the entire West rapidly went out of control. It hit the fan May of, I keep saying '98. I don't know why. But at any rate, in May 2000, San Diego, it paid off through stranded costs which basically meant they were now exposed to the market rate, wholesale market rate.

Moderator: The customers.

Speaker 4: The customers, yes. And this had a really negative consequence because these bills literally doubled or tripled like in a month. So, Senator Peace, who presided over 1890, also represented San Diego and this was not a pleasant time for him. At one point, when he was yelling at one of his kids about losing his cell phone, and he said, "Well, Dad, at least I didn't screw up the energy markets." So, [LAUGHTER] his own kids were like [UNINTELLIGIBLE].

So, at any rate, there was an immediate call for price freezes. Price gaps became a major issue and the reality is that the ISO Board when I served on it, basically we had price gaps, OK. We had price gaps and I think it was '98, '99 for ancillary services. We relieved those price gaps when we thought we fixed that problem, but there was always a default at 750. So, when you hear that California didn't have price gaps, that isn't

necessarily true. The question was, what should the price gaps be set at? There was sort of a default at 500.

I'm getting real wonky here, but it's important to understand that the debate was about the amount of money that you should be paid in the price gap, not the fact that there was a resistance to price gaps in general. And by the way, people were offering power at basically five cents a kilowatt hour and the state wanted us to do 25¢ an hour. So, that didn't make any sense. SDG&E requests in June of 2000, anybody can help us please do. There was a lot of response to that. I know that for a fact and most of those deals were between \$50 to \$56 for power based on what people could buy gas at the time.

PG&E and Edison also sought contracts to stabilize price volatility. My opinion is if a significant amount of that, you didn't need to do the whole damn thing. It would have materialized. We probably could have knocked most of the volatility out of the system. The state did not like long term contracts. And the Commissioner Lynch who had absolutely no experience in the energy area, was pretty hostile to them. Few contracts got forward.

And here's the subtlety because people would say, "Well, no, the utilities could have gone forward and done all that." In AB 1890, if the utilities bought out of the power range it was per se reasonable, no matter what the price was. OK. So if it was capped at 25¢, as long as they don't go above that. So, when they basically said "OK, we want a contract, we can get it for 5¢," her response to that was, "Well, yeah, but if next year's down to 4¢, you have to eat that delta. Well, the risk-averse. So, if someone, if *it's per se* reasonable to buy it out of the—

Moderator: Unless I misrecall, the PX didn't have a cap did it? Just the ISO. You remember, Speaker 2?

Speaker 2: I can't say. I think that's right.

Speaker 4: It jumped back and forth.

Moderator: Which was an incentive for the utilities to also move to the ISO.

Speaker 4: So my point is that the obvious solution to this was everybody was short. OK. And the thinking in the entire industry by the way at that time was go short. Because look at all the mistakes we made with the QF contracts and nuclear power plants and everything else. So, let's just go short.

This wasn't completely out of whack with some general issues, but there wasn't an opportunity to resolve that problem. Governor Davis basically announced, "I'm sorry, I'm falling back here," that he could solve this problem in 15 minutes, or whatever. Governor Davis was a person who wanted to make all the decisions, but couldn't make any decision. This was a character that was very smart, probably the most qualified person we had as governor, but when it came down to making decisions he couldn't, or wouldn't, because they were politically risky.

At this point in time, the Democratic convention was coming to California. I think he had a high expectations of his future. Didn't want to raise rates. Wanted to look cool and, well, the rest is history. He's no longer governor and at any rate, so we talked a little bit about the FERC response. I don't know that we need to add anything here.

Basically as I said, by August, 2000, we had reduced the price cap down to 250. That was approved by FERC. FERC took a couple of other actions in December. Replaces the ISO price cap with a breakpoint. This was very controversial. But basically they addressed it the best they could at the time.

I got a call at the end of December since I represented QFs. Rick Glick who at the time worked for the Department of Energy, for the secretary there. He said you represent all the QFs. Can you come to Washington because we've got to fix this? And the QFs at the time, particularly

renewables, since they weren't buying gas, they were kind of keeping the lights on a lot of places. But they were owed a lot of money, so there was a big concern about whether or not people would push Edison in particular into involuntary bankruptcy which didn't happen. OK. We'll just leave it at that.

So, basically outgoing president orders the secretary of Treasury, secretary of Energy and FERC chair to hold talks. Governor Davis, the entire leadership of the Legislature as well as all the CEOs of the IOUs and the IPPs, and QFs, show up in DC in the Treasury Building. And we all have these, this just turns too real for me. We're having these negotiations with respect to how to undo all this? Basically, they, IPPs, IOUs and QFs reached a deal, brokered by Secretary Summers and this literally was done in a bunker underneath DOE.

And just a side note. It's 10:00 on a Saturday night. And I'm having pizza with the secretary of the treasury and look at him and say, "You know, there was a table full of people. This is, I never in my wildest dreams or nightmare thought I'd be having pizza in a bunker underneath DOE. Having pizza with the secretary of Treasury." And he started laughing, "Me either." But that's what happened. So, we ended up with a deal and the Department of Water and Resources ends up procuring long-term contracts. That wasn't originally the recommendation of the person who made that, who thought that idea up.

Moderator: Wasn't that you?

Speaker 4: Yes, it was.

Moderator: Yes, it was.

Speaker 4: But I wasn't there and I didn't—

Moderator: You weren't in Sweden yet.

Speaker 4: I was not. So, the CEO of Dynegy was a great guy, was having a debate with Governor Davis because Governor Davis at that point wanted power for a nickel. And everyone

was pointing out, "Well, the nickel price was in June. The gas market's out of control and we can't substitute PG&Es balance sheet for ours."

Somebody had the brilliant idea of asking the governor's chief of staff, well couldn't the state back these defense actions and what the idea was leaving them. Basically, let the utilities continue to buy and whatever, and the state would back that up because obviously they were competent to do that. Instead that turned into, "Well, no, let's have the Department of Water and Research do it." And the rest is history.

So, the contracts were procured. Ink dries. Litigation ensues, full employment from the DC bar and everybody got to send their kids to private colleges. And I think there's still a case open. So, at any rate, just finishing up here.

Moderator: And did you leave the 202C Order out on purpose?

Speaker 4: Well, he already raised it.

Speaker 2: He put that on the white.

Moderator: It's almost like the key moment in the whole thing.

Speaker 4: Yeah.

Question: Who requires like—

Speaker 4: Yeah. I'm trying to find this. [OVERLAPPING VOICES] Oh, OK. Yes. So, the, I'm sorry?

Moderator: Keep going.

Speaker 4: Yeah, I'm just trying to blast through this, so lessons learned. Don't hardwire economic expectations and no legislation. There was assumption that if you go to market it's always going to be lower cost, not higher costs. And the market was not designed to move around. You didn't expect any major initiatives to run into

friction. Do not limit the ability to respond and we had a lot of that. The state-federal regulatory interaction was absolutely necessary. And in December 2000, could have gone a lot better with limited damage had that been better. Going short without adequate hedging leads to chaos with the market shifts, which is there and obviously suppliers, in my industry I represented a lot of people for whom competition is not only a good economic idea, but it's a religion. And it's very difficult to be responsive to the other political and economic consequences that are floating around in the energy market.

And then the last is hubris is dangerous. When we cast AB 1890 I for one could arrogantly wander around the West telling people how brilliant we were because we passed a piece of legislation that was voted on unanimously. And it wasn't until several years later that I found out that was perhaps not the brightest thing to be bragging about.

So, at any rate, my major concern is that looking forward as we're trying, in my state now we have SB 100, where we're going to go to 100% clean energy by 2045. No one knows what the hell that means. We're trying to incorporate demand, distributive energy resources into our mix. No one knows how that's going to work.

And just recently we find out that notwithstanding all of this that you've just seen and our eyes wide open, somehow we're between 2500 and 5000 megawatts short of resource adequacy in the date 2021, which is two years from now.

The whole point of talking about history is to avoid making the same mistake more than three or four times. And my concern here is to basically use what explains I think from the standpoint of mistakes that can be made and should be avoided in the future, recognizing the fact that the issues may be completely different. The markets may be completely different, but we need to learn from the past.

Moderator: So, why don't we take say a 10-minute break and come back with some questions back and forth. [APPLAUSE]

General discussion.

Moderator: All right. We're going to go ahead and get started for the final round of today's festivities. If anybody has questions raise your placard please. Since I raised mine first, even though we were not really starting this process yet, I will ask what really is a clarifying question. Oh, you beat me? Too bad I control the microphone right now. [LAUGHTER] So, I was just wondering, as I listened to our esteemed panelists talk, whether the economists up here have the same or maybe in a nuanced way, slightly different understanding of how they would use the word withholding in this context. Withholding output from generators.

Respondent 1: The Moderator asked during the break if we'd answer his question for definitional purposes, so what I mean by it in this context in withholding and exercising market power on the generation side is either by physically removing it from the marketplace, or by putting in an add that's physical withholding or economic, or putting in bids that are offers that are so high that it won't be taken, or taken at very high prices.

And it's therefore not producing and the key is that then in the end, in real time the generator does not produce electricity and the prices above their marginal cost of producing electricity. And so, and that's to distinguish between the situation where they are producing electricity and they're getting paid a price which is substantially above their marginal cost. That's called scarcity rent. And I don't consider that to be, so the actual not producing in a material quantity when it would in fact as a narrow decision for that generator alone, would be to produce because prices above their marginal costs. And the usual assumption is they have a lot of other generation which they can benefit when they have higher prices. But if

they're not, if they're not physically withholding or bidding in such a way that they end up not producing then it's not withholding it's a scarcity problem.

Respondent 2: Let me just say I think I basically agree with that in terms of how I would define withholding in this context. And then the issue is should withholding by either of those definitions be deemed illegal, unreasonable, contrary to the Federal Power Act.

And that's an interesting legal question. Because I believe that what these guys did for the most part was probably engage, and I never really studied this in detail. I should really put that caveat in there. And we had parts of the company that have studied this much more than I.

But I think certainly if I was a generator I wouldn't absolutely withhold, I'd stick in a hockey stick bid and hope that others would too and hope that we'd all get a nice fat price. And then the issue is, "OK, so what's wrong with that?" And then we'd get into the interpretation of what's just and reasonable under the Federal Power Act?

Respondent 1: The hockey stick bid, you put in a low price for 90% of your production and a high price for 10% of your production and you hoped you'd end up getting the high price for 100% of your production. That's scarcity pricing. Hockey stick bid, when you put in and you put a low price for 90% of your production, a high price for 10% and the price turns out to be above your variable cost, but you don't produce the last 10%. That's economic withholding.

OK. So, it's not the hockey stick *per se* that matters. It's the shape of those over curves. That's what actually happens. And if you produce 100% of what you could produce, you're not withholding. No matter what price you charged. That's scarcity pricing.

Respondent 3: And I don't disagree with that, but then I go back to the legal issue and that is: Is scarcity pricing illegal under the Federal Power Act? And that calls for I think a legal interpretation. Economists may wish these laws were all written by economists and that that would be perfectly legal, but the issue is what's just and reasonable.

Respondent 2: Well, FERC declared to be in a case that went to the 9th Circuit. But that was just recent. The 9th Circuit ruled in 2016. When I was at the commission, we were quite aware that, I think it was called the MMIP, the Market Monitoring and Information Protocol. Is that what the I stood for? Anyway, it was perceived to be part of the tariff and it prohibited gaming and anomalous behavior.

The problem was FERC had never really defined what gaming was or anomalous behavior was. After the fact, as I recall, perhaps years later, anomalous behavior was defined to include economic withholding, but that wasn't clear when I was at the commission.

Moderator: So, let me make a couple points and I'll start calling on people unless those points stimulate a little brief discussion.

Just to make this point clear, whenever you talk about the California Energy Crisis, or the Western Power Crisis, there're allegations of physical withholding. Well, the machine was broken, but not really. That almost always involved allegations of the group that used to be called the Big Five, [Donich and Myclyde, Duke, Mera (SP?)] and Southern, Williams, I'm forgetting someone. And all those companies settled before there was a litigated resolution of what actually happened.

But there was never, at least anything that I saw, and I used to challenge the lawyers on the other side to point me to something I missed and they never could. There was never an allegation of actual physical withholding that held water. Instead, what the evidence really uniformly

showed is that generators are mailing huge pieces of equipment by overnight planes to get it there because they wanted to make \$500 an hour.

And if you were going to go down the road of physical withholding in your plant, that could get you into a hell of a lot of trouble and for all you knew, that ISO would just engage in some sort of out of market activity, if you really wanted to go down that road, and the price wouldn't go up anyway. So, there was never any persuasive showing that anybody ever did that. The CPUC came in with some allegations pointing to a few instances, Speaker 1 was talking about this.

The FERC staff looked at those instances, found them to be a dry hole, so the physical withholding I think ends up being a canard. Economic withholding in the decision, unfortunate decision that Speaker 1 referenced, and you remember this because you were one of our experts. But prices and get ready for this, prices as high as like \$42 a megawatt hour were considered to be economic withholding.

Because the rubric used to figure out how to look at that question was engineering system-wide, short-run marginal costs. And if what you're going to do is you're going to reprice natural gas, which is what happened here to base and plus transport, gas is not expensive. What's O&M, two or three bucks? All of a sudden the whole system is supposed to be clearing it at \$40 and if you offer above that, you've engaged in economic withholding.

That was I think, an unfortunate journey down to a sort of economically nonsensible outcome, but that's what happened in litigation. And we forgot all about the question about long marginal costs and how the price is ever compared to that. Which is probably a better question if you look over a longer time step.

Respondent 1: Yeah, no I just wanted to comment on the issue that I brought up to you about Speaker 4's comments. Speaker 4, I don't think that you necessarily intended this, but I

didn't want the audience to be left with the conclusion that Southern California Edison was so risk-averse that it just accepted buying everything out of the spot market, because it was *per se* reasonable.

In fact, going back to late 1999 and going into the year 2000, Edison made a couple of applications with PUC for a lot of forward contracting. And the PUC came back and allowed about this much forward contracting. And then a couple months later the PUC put forward a framework that said, "OK, if utilities want to engage in forward contracting they can, but they need to submit their contracts for reasonableness review to our PUC staff." This was around the time that we were all trying to get things settled and Duke was, as I recalled, offering a good amount of power for something on the order of—

Moderator: 75?

Respondent 1: It wasn't. I think it was less than that at the time. I think it was maybe 55 because I'm going back to late November, early December and my recollection is that Edison actually entered into some contracts and submitted them to the PUC.

But then the PUC staff just sat on them because, and this goes back to the issue of wanting FERC to act first and the finger-pointing: "No, we don't want you to sign those contracts," or, rather, the PUC staff is, "I'm not going to be eager to review these contracts for reasonableness because I may come out with some conclusion about the reasonableness I'm going to be criticized for later, after FERC quells the prices, and I'll get blamed for it." And so, the PUC staff sat on it.

Now I said I was going to tell you one story out of school, and I may do that and I think it was probably in regard to those contracts.

I was at a meeting, I remember it, Ritz-Carlton in Pasadena and it was a small meeting and I guess only about 10 or 12 people there. But Harold Ray who was our COO, who was responsible for the

forward contracting going back into 1999, was frustrated during that meeting. Frustrated I know in conversation in coffee breaks and things, that he wanted John Bryson to confront the issue and decide on a considered basis one way or the other, whether Edison should just bite the bullet and sign those contracts and take the regulatory risks on those contracts, even though the PUC staff was sitting on them.

And I don't know if they ever succeeded in joining that issue, but I know he was trying to get that issue in front of Bryson and have him not make the decision by default, but make it deliberately. And I do know that Bryson at the time was very much inclined to think, "No, I'm not going to take on much risk. We're going to take this thing all the way."

But my recollection was that it was a sizeable amount of money that might be at risk on the reasonableness review. Like half a billion dollars. Now, when you look back on it, at the amount of money that was spent during the duration of the crisis, spending half a billion dollars would have been a hell of a bargain in terms of somebody taking that risk.

Moderator: It would have taken a hell of a lot of courage, though.

Respondent 1: No, that's right. But I think John believed that it was his fiduciary duty not to take that hit. I mean I think he was really somewhat, well maybe not embellish what I think he was thinking because I don't know what he was thinking and I don't even know if the issue was ultimately confronted by him.

I just put that on the table to indicate that we did have contracts out there. They were submitted to the PUC and there was some consideration at least among senior management, even if it was or was not the CEO, of just biting the bullet, signing the contracts and trying to solve the problem. That never happened.

Moderator: Thanks. Wow, what a history lesson in reliving everything. Speaker 1, do you remember back in the day when we were working at FERC together, you and Dick O'Neill and I'd be sitting down there in the gym on the treadmill or the bike and talking about these things, and trying to keep Humpty Dumpty together? I guess we didn't succeed, did we? But it --

Respondent 1: No, but I know you guys said a lot of concern about the market structure.

Moderator: Absolutely. But I think what's interesting here is that we talked about the market design. But I think Speaker 4, your presentation hit on every little thing and Speaker 1 brought up another issue, is that we has the El Paso pipeline explosion which reduced gas availability and increased gas prices.

I think one of the biggest untold stories of this are the air pollution credits or allowances with the South Coast Air Quality Management District Program where the price went to about \$42 per pound of NOx. And when you add that into the cost of generation, I mean we're talking hundreds of dollars of megawatt hour for a CT. And that doesn't get enough attention here. Obviously a bad hydro year.

One of the things we're also missing is that the 2000-2001 winter was one of the coldest on record at the time. Of course with climate change that's not happening anymore. The other thing that came up and I think Speaker 4 you said something about Dan Fessler, who's a good friend, and he was saying "Yeah, the U.K." But you know what they really did? They took the Nord Pool model and applied it. If you think about how Nord Pool is put together with a power exchange separate from system operations, that's effectively what happened. It wasn't like the England Wales Power Pool.

So, with all of this perfect storm, and the bad market design, let's assume away the bad market design as a true economist. I'll assume the can opener if you will. What if in spite of all those

perfect storm pieces, if we had the right market design at the wholesale level, would we be talking about this as the California energy crisis?

Question 1: Does that include bilateral contracting forward?

Moderator: That includes bilateral contracting forward. If we had the right market design, soup to nuts, at the wholesale level.

Respondent 1: Well, I think prices would have been higher for a lot of reasons, but I don't think they would have been as spiky and I think if it was hedging around the spot markets, that would have calmed things down fairly reasonably.

There might have still been some pain in California because prices would have been higher anyway, I think. Because of the supply and demand fundamentals and other issues. The link between gas and electric markets. A lot of the issues you raise. But I don't think it would have been as disastrous as it was. I think it would have been manageable.

Respondent 2: Let me just respond for just a second. My response to that would be I agree with Speaker 3. If there were forward contracting, because then it wouldn't really matter whether there was a really high price because it wouldn't have the same political implications.

But if you combine, let's say, a perfectly operating market, but still with a retail purchase obligation imposed by California. And remember California shot back at FERC in December when they were, when FERC told them to get rid of their mandatory purchase and they said, "You don't regulate the buyers, we do." And so, they shot the PX. One of the more unseemly episodes of the entire encounter.

And if that were the case, if you had a perfectly operating wholesale market, but you still had high prices, and they were propagating through, I think you'd probably have better wholesale prices, but in theory you could still have high wholesale

prices that were a huge political problem and a lot of people would say, "No, that's not a just and reasonable rate." And if you had enough political backing behind that viewpoint and you would, if you were subjecting enough retail customers those high prices. You'd have a problem.

Question 2: So, question for everyone on the panel. I was wondering how does the California experience inform our current debate and discussions about market manipulation, using only financial positions under the head market?

Moderator: Well, the word Enron's thrown around a lot in every case practically. But I think it's just rhetoric. So, I would say there aren't really relevant lessons to be learned between those two different eras and two different sets of allegations. But maybe others have different ideas.

Respondent 1: Well, in full disclosure the questioner and I have worked on this problem together. I've written some papers on this subject and my starting position was if you don't control generation in the real-time market then all you're doing is using financial transactions in the day ahead market. You can't exercise market power in the day-ahead market and you can't manipulate it and profit from that. That was my starting presumption.

The questioner found some interesting writings from the financial literature changed my mind and then we said, "Well, here's a way to do it in the day-ahead market, under certain assumptions." And it's really hard to try to exercise market power, but it does have certain empirical implications.

The importance of that paper was to say, "This is not a vague discussion about anomalous behavior. You have to have this condition, you have to have that condition and there's a series of conditions. And so, that's what we should be looking for empirically." The critical condition in this theoretical approach is that you have to be able to randomize your holdings that you're

making, changing the price here and making money over there.

So, the holdings over there have to be randomized and every trading period so that Andrew Stevens doesn't know what you're doing. And if you can pull that off, then you can manipulate the market and have a sustainable opportunity to exercise market power. But the FERC enforcement of it could go, "Look, are you randomizing your holdings and actually doing this kind of trading?"

That's the empirical task and to the best of my knowledge nobody's ever done that, ever looked at it. I don't think anybody's ever done it and I think it's too hard. So, it's not impossible in theory. But I think it's a really hard. The place you want to worry about market powers and equitable physical generation is in the real time, which we already talked about.

Moderator: OK, we have a batting order for questions. We got to watch the Mets tonight by the way. Go Mets.

Question 3: Thank you first off, this is a terrific panel. And it's great. I love history so this is a great panel. Two quick questions. One, Speaker 1 had brought up the DOE to see if somebody could remind us about that. But the bigger issue, if I could go back to the legislation.

My recollection, obviously I was far from it, was the whole focus was on market power of the incumbents. That was the rationale behind forcing the utilities to be 100% in the spot market. And Speaker 4, I wondered if you could just give us, what was the thinking at the time? What was the focus at the time? Was that it or something else that drove the idea for them being in the spot markets? So, the DOE question and then this other question on the rationale.

Respondent 1: Well the DOE question, the issue, if I recall correctly, there was an order basically that was effective throughout the West, basically that required people to operate the power plants. To make a long story short.

Questioner: The key part was that sector energy [UNINTELLIGIBLE PHRASE] for others and the administrations changed. There were four other orders they had signed by Secretary [UNINTELLIGIBLE]. So, Republican and Democrat.

Respondent 1: Got it.

Questioner: Saying that everybody in the West had to sell excess power that they did not use, or that they were overloaded in California and that the order said you get paid something. We don't know what price. That would be determined, but it was to be positive. It was the fear that nobody wanted to sell to a bankrupt entity and potentially bankrupt entity.

And so, Richardson, with Richard [UNINTELLIGIBLE] who was chief of staff, ironically, issues an order saying that you must sell excess power into California. You will get paid. You do not have to worry about bankruptcy. That was in effect for almost 14 months.

Respondent 1: That's my answer. So I guess there were two issues that were resulted. One was with respect to the divestiture of the fossil units. They wanted to be sure that utilities didn't have market power, and they would somehow utilize it in a way that would affect this new competitive market. And it was a 50% requirement, not a 100%, but it is said.

And then the other was, basically, there was a big concern and I'm going to oversimplify this that some of the pushback for the PUC then, and that was under Dan Fessler was a concern that, yeah, it was great for all the commercial industrial guys. I want to go grab all that cheap Washington power, but we need to share that with the customers in general.

And so that was the idea that the utilities would basically purchase whatever they're purchasing, put it in the pool and then buy out of that pool as

well and leave it as a wash, more or less. You might have another perspective.

Respondent 2: The only thing I would add is I think there was a lot of concern that the short-run market would be very deep and liquid to facilitate and encourage retail competition. That the retail, competitive retailers would have a place to go immediately and get some power.

Respondent 3: And as I recall one of the arguments for relying so heavily on the spot market was it was an objective way to measure whether the utilities were recovering their stranded costs. Because there was so much confidence that the wholesale market would produce low prices. And a lot of confidence that over time the utilities, because of the head room between the low wholesale price and the higher retail price, would recover all other stranded costs.

Questioner: You've got a thing going on with valuing, trying to value [OVERLAPPING VOICES] and the cost.

Respondent 3: How to value that objectively in the spot market was the mechanism. [AUDIO CUTS OUT]

Moderator: —but didn't the pipeline capacity, it being out of service mean that they had to draw down their storage resources for one?

Questioner: —second point is Bill Fancy was chairman at the time all this started, right? He was the one in charge with the commission privilege, right?

Respondent 1: Yes.

Questioner: So, just [AUDIO CUTS OUT]. There was, it depends. At the highest levels of government and I mean that literally.

Respondent 1: I'm not beating up on Betsy. I thought she was a terrific chairman. I'm actually beating up on myself. I shouldn't have voted for

it because I knew better. But you know, hindsight is always 20/20.

Questioner: I wasn't suggesting you would do it. I feel like some of these mentioned did. But her hands were really tied at one point. Here's the real point I want to make. The beauty of these kinds of panels at Harvard is, what is the lesson learned and how do we apply it into the future? That's what I think we're trying to do here.

So, I take away from all this, and this will be news to some of your ears and some of you will push back terribly. I think about all this is that capacity markets are inherently flawed. Because they're not really markets. We have to build in so many rules in order to have these capacity markets for security-constraint reasons, for reliability reasons, for fuel reasons, for all kinds of reasons that they're not really markets.

And the reason I believe we still have capacity markets, the reason I think we're going to make the same mistakes again, and again, and again is we now have a capacity market because most state regulators, common theme, like the fact that they can point at FERC. And say, "Wow, look, these capacity markets don't work. Why is all this stuff not working?"

So, isn't really the lesson here it's time to just, Speaker 1, I'm not trying to throw you a softball, I care if you did although, [LAUGHTER] you're perfectly capable of doing that. Isn't this time to just say to the state regulators, isn't it time for FERC to say, we got to get rid of these capacity markets. They are currently flawed. They're not really markets, they're administrative constructs. And until we do that, until we bite that bullet we're not going to learn lessons in California. That's my hypothesis. That Oak can offer you the softball first. I agree, you know, but that's the lesson of mine. [LAUGHTER]

Respondent 1: As you know, I'm not a strong fan of capacity markets. So, but there is a problem and which I have to address and Texas has confronted this problem directly, which is the

difference between the quantity of investment and the reserve margin you get with efficient scarcity pricing. That produces one level, order of magnitude. In Texas I think the number's like 13% or something like that reserve margin. Versus the one-day-in-10-year standard which requires like a 17 or 18% reserve margin.

That gap between those two outcomes is a critical part of the story. So if you want to get rid of capacity markets you have to confront that problem. Because the market by itself with scarcity pricing will not produce one-day-in-10-year investment in that level of reliability that comes out of these models.

Questioner: I don't disagree with that, but that is, in my judgment, putting aside letting them think that one-day-in-10-year is still the right benchmark at 17%. Because it's never actually been implemented in a way other than in theory because, thank god, we've never gotten to that point other than for reasons unrelated to the actual one-in-10 basis.

Commenter: But then partners are getting further though, right now. The benchmark is not one in 10, it's one in 50. The assumption is now one-in-10 actually happens five times in one. [OVERLAPPING VOICES]

Commenter: But the point is, that's the problem you address, is it should be easier to solve than continuing to have these artificial capacity margins. And I think that's really trying to—

Respondent 1: Well, I agree and we've written about this and made record, about this in the context of the Texas situation and said, the capacity markets are not the only way to have a higher reliability. Another way to do it is you shift the demand curve, the operating reserve demand curve a little bit, which they actually did. And that has a lot of advantages to it because it provides the price signals at the right time and the right place.

Moderator: I'm now remembering and I went to talk to Susan because she helped us on this, in the third refund case trial that you laid out, was it the ISO operating reserve demand curve on top of the California markets in 2000, and actually the summer of 2000, and found that given the tariff-based triggers for those prices to exist that that validated the California summer 2000 prices from a demand-curve, operating-reserve basis.

Respondent 1: So, I'm a big fan of the operating reserve demand curve. But I'm just trying to respond to Speaker 3's point here, which is you can't, as much as I might be emotionally in that direction, you can't wave your hands and say capacity markets should go away, if you don't confront that problem.

Respondent 2: I didn't mean to suggest that. But for me, the ultimate question is, that FERC was, this is one of the questions that pisses me off the most. The FERC was never meant to be, it was never intended by the Congress to be a responsible entity for ensuring the retail load concern. That was never the construct of [UNINTELLIGIBLE PHRASE]. And because of the restructure we have moved it away from the state regulator, who should be responsible for it and it was statutorily responsible, FERC. And FERC can't ultimately do anything about it.

And so, I do think the lesson that should be learned, and I think you all, I think you're right. The comparative lens is that California was ultimately compared to, California was the one who is responsible for it and California should have been the one to fix it. Now I fear that we're going to keep making the mistakes yet again and allowing the states, the state commissions and the state legislators to not be responsible for the mess. They're the ones that have the responsibility for reserve load. That ultimately to me has to do something.

Moderator: You should have been here for the panel this morning.

Respondent 1: So, you'll be happy to know that California explicitly rejected the capacity market because it will be under FERC's jurisdiction. This is after a three-year settlement with all three utilities and the ISO. So, that didn't happen. We're now trying to come up with some sort of mechanism, RA mechanism which is going to be probably even more problematic and I'll just leave it at that because it's a state issue.

And then your first point, and that's why I brought the letter because the reality is, the people who put this letter together, and I was part, there was a group of us that came out from California and basically said, "Betsy, hands off." Because we were concerned that there was going to be changes imposed by FERC. And so, your point about the political pressure is absolutely true.

And I want to underscore that here simply because this is filled with legions. If you believe the narrative in California, it's "Enron did this to us and they brought a bunch of taxes and they picked our pockets and they ran away and FERC let them do it." OK. Well, that isn't what happened. OK. And one of them was that FERC was asleep at the switch. Well, when you get a letter signed by 53 congressmen, basically saying leave us alone, they did what they were asked to do, so.

Respondent 1: Moderator, just before we leave the gas issue, I'm sorry. I just wanted to remind people that, first of all, I realize the gas market nationwide was pretty squirrely during this particular time. But it was especially bad in California. It went up to \$60 in MCF.

And I know that there was a lot of anti-depressed hubbub, but I don't know what exactly finally happened to that, but there was a big hubbub about anti-trust arrangements and restraint of trade on the El Paso pipeline. I just wanted to remind people of that. And I don't know if that was resolved.

Comment: But there was during that time, we know by criminal verdicts and guilty pleas, there

were people who apparently intentionally misreported natural gas prices to the trade press. But that's like a game of pennies. That doesn't move the price to \$60. It moves it one cent or another, wherever the index price prints.

Respondent 1: I have one more comment. Yeah, there were a lot of problems California could have fixed. So, what if you're sitting at FERC and you've been moving to markets, you've opened the markets with Order 888. You want them to work well and you're faced with this crisis. And you think a lot of the problems California can fix, but they're not fixing them. And it goes on and on and on. And you see a lot of the work that you've done to try to have some markets with credibility is going down the tube.

What do you do? I'll tell you. We should have shut the thing down and fixed it. We should have had the political courage to do it. And start it all over. That's my view. But we didn't. We didn't do it. We let it go on for 13 months and then we fixed it. And it's very hard to fix a market in the middle of a crisis. Very, very difficult, but, and looking in the rearview mirror, it's easy to say this, but I think that's what we should have done.

Moderator: Next. Let's try to move through the queue.

Question 4: So, this discussion is fascinating and I'm actually now a little bit confused. And I'm curious to go back to the discussion among the speakers about market power, scarcity pricing and hockey stick pricing, but there's also been discussion about gas prices. And I'm curious what the data shows about what the heat rates were and whether they were that much higher, because I remember at the time the conventional wisdom being these prices were crazy high. And then I remember thinking back to that in October of 2005, and thinking, "Boy, those California energy market prices were actually not that bad at all." And then rethinking that same thought in the summer of 2008 and again in the polar vortex in 2014, where you see the markets actually having these kind of dynamics.

So, I'm curious if there's any data about the extent to which the withholding and gas prices and heat rates were at an extreme level, and obviously the electricity market was tied to the hydro. Or, gas and if any of that has been parsed out. And then I have a second question, which is how much of the ultimate cost of the crisis was due to the spot prices and having to buy power for the bankrupted utilities, or maybe bankrupted utilities during the actual crisis? And how much of the lasting impact was due to the long term contracts that got signed sort of at the height of the market?

Respondent 1: That's an entirely reasonable [UNINTELLIGIBLE] of the contract.

Questioner: I'm just curious you know, just the balance of which is which. And then one more question is I'm curious if the price caps themselves, given the other market design flaws, had an impact of exacerbating some of the energy market prices.

Because if you're a generator, you can sit there and sell in the day-ahead market in one market, and you're capped at like 100, but the balancing market is uncapped and you want to be available in that market because it's much higher. And whether the price caps actually were the wrong solution to the problem. And the idea of just going back and starting from scratch would have been better. Three questions, sorry.

Comment: Any thoughts on heat rates? I mean.

Respondent 1: I'll take the easy one, the first one. So, which is as I said before there's no documented examples of physical or economic withholding of generating plants. That doesn't prove the negative, but we have—

Questioner: By now, one might surmise.

Respondent 1: You would think. And that's the statement which I think is completely straight forward. So, were the prices consistent given the natural gas prices? And the answer is, in heat rates, and the answer is yes. As near as we can

tell. So, the argument has been for people who are trying to make the other cases, well, the way the manipulation was actually done was not by the electricity market. It was done by manipulating the gas market and manipulating the air quality permit market. Those two things. And that's a much harder question to go back and pin down. My own view is no. That there are very good reasons why those prices were high. But I think that's more controversial.

Moderator: Next question.

Comment: So, for full disclosure Joel got me into this mess in 2000, by hiring me after SDG&E filed their complaints so he gets the blame.

Question 5: Yeah, so I think some people in this room are still suffering from PTSD. Having gotten into this sometime after the Blue Book and with Dynegy from '98 through '02. First, just a quick comment and it sort of goes to some of the issues going into the summer of 2000. One of the things people also forget is that 60% of the gas generation fleet was 30 years or older. Many units were 40, close to 50 years old. A lot of outages, and the generators of course were subject to paying the real-time price, if there was an outage, and that, looking back and thinking about it, probably played a part into the psychology going into the summer.

And then, the last thing is at a certain point we keep calling it a market, but probably by October it's pretty hard to call it a market. I mean I think it was pretty well foreseen that with the retail price cap that the utilities could go bankrupt pretty quickly. Prices were very quickly going above the \$250 price cap and generators were still being required to run at a loss. And once the 150 cap came in and you had a 90-day period between the time the market ran and the generators were paid, there was a crisis meant to happen.

There were so many things going into this and I forget who said it, the perfect storm analogies. And I think it's true. My comment. My question is really, Speaker 2, in your comments you talked

about it was clear that the rules were being gamed during this period leading up to the crisis. And one of the things from my experience being at Dynegy is we used to tell the Cal ISO exactly how a proposed rule would be gamed and then they would just put it into place. And history ran its course.

But one of the things that I think that really highlighted was a potential differential between the marketers for the larger companies, Enron, others and perhaps many of them with MBAs and otherwise. And those basically became the marketers for the utilities. I was wondering if you might be able to comment if you've ever looked at how unequal perhaps the knowledge was going into the market, how the markets worked between those who were working for the utilities, who often had had other jobs within those utilities, before the market started. And perhaps those who were in the larger marketers in the course of things.

Respondent 1: You know I guess, I'm trying to recall exactly what some of the timing was in terms of the Edison Company building a big staff, but I think, I think at this point they really had quite a professional staff. I don't think the utilities were disadvantaged in not understanding a potential for gaming and the operation of the markets themselves. I think that they were probably of comparable sophistication by this time as Dynegy and other marketers. That's my recollection.

Although I do recall that we even beefed up things all the more during the next few years. So, my memory on this is a little bit muddled, but I think there were plenty of sophisticated people on the market. They were employees of the utility.

Moderator: I actually meant to make a comment myself about the reference to gaming the rules, and I guess stepping back on it, what I would say is they're all the colorful names that the Enron memo used. Most of which had only a glancing effect on clearing prices, if any, and a number of

which were sort of intertemporal arbitrage that really the rules should have allowed.

And you could say they were end goal violation, but that's not how prices got to be \$500 a megawatt hour. I'll tell you who did really game the rules is PG&E. Because they were trying to figure out how to move their purchases, when they should move them from the PX, which had relatively low prices and very high volumes, to ISO which had high prices and low volumes. And there's a crossover point there. It's just like what you look at if you face a kink in a supply curve and you kind of would prefer your load not to climb up that kink. So, PG&E, as I recall it, created a computer program, someone did. I guess the company didn't, but people there created a computer program to figure this out.

And then they filed testimony at the CPC explaining how great they were for doing this. And we looked at this 10 years later and went, "People could go to jail for that now." It's a lot like in the NEPCA fights about capacity markets and the MOPR. Remember the [Dripe SP? 6:10:30] report where all of New England decided to get together and figure out how can we save billions of dollars by just avoiding going up that kink in the supply curve by doing economic things? But that was sort of viewed as load trying to reduce prices and, so, nothing really every happened.

Question 6: Well, thank you. This has been really informative, especially as a transplanted Westerner. So, if one of the major lessons is that you should have load serving out of these, cover their positions by forward contracting, I wonder how you sort of apply that lesson to today's circumstances in the West where you have all sorts of different business models on the part of LSCs.

You've got the California IOUs, which by regulation are supposed to be indifferent financially to the contracts for RA that they signed. There's always ways for them to make or lose a little margin in it. You have the other IOUs

in the West who stand to gain financially by overbuilding and over-complying with resource adequacy through rate base.

And then you have the CCAs and direct access customers who want to under-comply probably on the hope that someone will either ride into save them, or that the guys who are financially incentivized to overbuild will have to pay the costs. And they'll just be able to kind of regulatory arbitrage around to steal the business of the incumbent IOUs.

You introduce that to a scene which has more and more questions about the sort of forward capacity that resources actually dependently deliver, and you get a variety of different response. I mean two different state regulators can look at the same wind farm under two different sort of integrated resource-planning scenarios and come up with two radically different answers of the amount of capacity that wind farm can be said to deliver. Some people are using ascendant methodologies still. Some people are using ELCC. Some state commissions are still using educated guesses that were found in 1990s National Lab reports. That's what I did when I was a regulator because there didn't seem to be a lot of better evidence.

And, so, I agree with all the criticisms of a capacity market which sort of defines what these product are and are worth, and sort of centralizes the disposition of questions about what people need to carry. In the absence of that, you have this sort of scattershot, multiple-state regulation that tries to impose capacity requirements on load-serving entities, but often doesn't do a very good job of checking their math and doesn't check the math of the entity they're regulating against other entities, and certainly not against other states.

That seems to be the main pitfall of the argument because the West is always dependent on interstate transactions for capacity. It's never been one state can just regulate its own capacity and its own resource adequacy. It always ends up being reliant on others. So, I just wonder what

that whole debate might tell us in the context that we are today.

Respondent 1: At IEP we used system weege. It's as accurate as anything else out there in terms of determining what you need in the future. You're actually hitting on an issue that is surfacing and I suggested this earlier, that there's this 2021 problem showing up, and people are going how being all 50 megawatts or even 500 megawatts off what you thought was going to happen in 2021 is probably understandable. Being 2500 or 5,000 megawatts off is pretty significant.

A couple things have happened. One, the coal wars have been largely won in the West. There's a lot of coal capacity shutting down. Which means the natural gas plants that were built in those sectors are staying where they are. Two, a lot of the states in the West have adopted policies, RBS policies and green policies that basically mean that a lot of the gas generation that used to come into our import market may not be there. And so, this is putting a squeeze on it. And the other issue is we recalculated our ELCCs and reduced fairly significantly the amount of capacity we're expecting from solar and wind. OK, so those three things have all converged at a point in time where it's gone like "Holy moly, we're in this mess."

So, the ISOs brought this forward. They're working cooperatively with the PUC. We'll see what happens there. Now, the scary part. The state having been through this all at once is trying to figure out how you do it. The utilities are going, "Well, why do we need to buy this stuff because our loads going off the CCAs. Community Choice Aggregators?" These are muni likes. They don't really have anything to them other than the fact that they were joint powers agency.

So, they're going, "We don't need to be buying this stuff because we're losing customers." The CCAs in some cases aren't really positioned to buy a lot of this. This has become a debate. In

some cases, they're doing a great job. In other cases, not so much. So, now it's, "Let's come up with a central procurement entity." OK, so now their hairs are going up on the back of my neck, going, "What does that mean? Does that mean my PUC is buying power on the behalf of everybody out there?"

And this is the PUC who believes that, as gas plants go away and prices go up, that's market power. It's not shortage. It's market power. So, that's what's next. OK. And there may be in fact legislation next year on this. So, that's the next step and , as we go to more DER and other stuff, we atomize our system in such a way that the question of who is responsible ultimately to keep the lights on becomes a little less certain than perhaps it used to be.

Respondent 2: Just as a historical footnote, California has not always relied on out-of-state capacity. Although you'd have to go back to the 1970s, back to a period that I actually remember. I started working for the utility in 1965. And back then we simply did economy purchases, this is when the utility was in charge in no uncertain way of serving the load and operating the system. And they had enough capacity to serve all their customers, and the economy purchases were economy purchases. Now that's long gone.

I just wanted to add as a footnote, I just wanted to emphasize that as one of the institutional ways in which the industry has migrated far from that. And the other side now were at a point where the utilities have been asking themselves for some time, "Why are we procuring?" I retired 12 years ago, and this goes back to a period before I retired: "What's in it for us? Why are we buying this power?" It's an all-risk, zero-return business. We had lots of people internally, and now with the CCAs, you've got even more people saying, "What are we doing in this business?"

And I don't think I'm telling any stories out of school, because I'm actually not in school anymore, but PG&E, I think, would be perfectly willing to get out procurement all together. And

San Diego Gas and Electric is almost there. I'm not sure what we think about this in this new world with CCA. So, when you talk about California, you wouldn't believe how many balls are in the air right now.

Question 7: Thanks. Just a question. Now these are not adjusted for inflation, but I'd just like to understand is there still a problem in California with the markets? Because if we go back to [LAUGHTER]. Yes.

Comment: No, there's no problem at all.

Comment: Well, just to put it in perspective, in '94 they were paying \$100 a megawatt hour for retail. For all markets. In '98, or '99 they were paying about 90. And then through the crisis and everything it jumped. By 2006 to about \$130 a megawatt hour. Gas prices went through the roof at that period, but now gas prices have dropped significantly. And they've gone up to \$160 a megawatt hour now, across all customer classes in 2017. That's 2017.

I don't know how high they are right now today. But are the markets part of that? What's happening that's just driving prices sky high there?

Moderator: I don't know renewables, but one of the things that's underneath all of that is the ISO clearing prices have remained quite low for a long period of time after the crisis, which is what my long arm cost point was. If you look at contributions towards margin and how you could fund a new plant, those studies which Hildebrandt has done for many, many years, there's this little small tail to them now.

And so, I've always kind of wondered what the bid deal was, because if you wait 13, 14 months the whole problem went away, but I lost that argument.

Respondent 1: Well, let me see if I can add to the confusion. The renewables have been interesting and I represent wholesale renewables, not the distributive guys. But we've got about 11,000

megawatts of utility-scale solar and I think probably 7,000 megawatts of wind. Six to 7,000 megawatts of wind. And then from geothermal and biomass, the issue that was talked about this morning with the solar now is, in terms of wholesale prices, two to three cents to build it and the marginal cost in the middle of the day is zero. And that's created a big problem for the gas lead because that's where you used to make your money.

The gas lead is not needed in the middle of the day. It is absolutely needed between five and 8:00 at night. Otherwise the lights go out. And the gas lead has shrunk significantly since the discussion we just had. We had once through cooling, so all those old Eisenhower plants up and down the coast were basically given 10 years to shut off or repower. A number of them were repowered. The last one wasn't. That's an old, I need alcohol in order to talk about that one, but the reality is that while the rest of you are talking about replacing your coal plants with gas, in California gas is the new coal. So, we're fighting, we really get defensive action there just to keep the gas plants that we have functioning in the market. So, that's one of the issues right there. That the number of gas plants have shrunk.

As I said earlier, the PUC is now seeing that as market power because you have fewer plants providing that power and then, in their minds, the prices go up, that's a reflection that someone obviously has market power. So, that's a key problem there. And so, in terms of the energy prices, we'll see how this plays along in terms of the energy market in general. The big problem is, is the ISO just pointed out, as I said, the issue with respect to the kind of the shrinking RA for lack of a better description, but a big problem is we have a December because of the way this works. We have a December ramp of almost 15,000 megawatts in three hours a period of time. So, we just talked about the import shrinking. That's likely to happen.

And you have just a fixed amount of internal generation that can come at a drop of a hat with

respect to the gas lead, so this is a significant issue coming forward as well. How you price that is a big issue. And so, that's an area we need to pay attention to and then, last but not least, the other big thing that's popped up to the ISO is we do have periods of time in the winter where you know you don't have sun and you have very little wind or whatever.

The Germans have a word for this because they have a January. There's two weeks of that happens to which they fire up their lignite. So, it's a longwinded answer to say that the market there is really in flux and we have all these little different problems that are popping up. And a lot of policy decisions that are trying to push things into other types of technologies that may not really fit particularly well. That's your future. That's kind of why I'm here.

Comment: How fun.

Moderator: I see more questions.

Question 8: All right. So, I do have a question which is not intended to be rhetorical. It may end up being that way.

Moderator: Why am I not surprised?

Questioner: I think what I really want to take away from this is lessons learned for today from what happened 25 years ago, or however long ago that was. And then he sort of deflected and went off into a diatribe against capacity markets. But I want to think about where we are today.

To me, an overarching lesson here is that you shouldn't set market design under political duress. That seems to be what happened there. And I think we are moving back into a time in which there are political pressures, at this particular time from two sides. From states, this is particularly difficult in a market that has multiple states with multiple political goals.

So, I'm thinking of PJM or New England. Think about how difficult it was in California. That's at least one state with one ostensive political goal.

And then you have pressure on the federal side. This is what I was sort of getting at when I should not have spoken out of turn. But we're now dealing with a pressure to plan to reliability standard far beyond one intent. It is now typical for black swan events to be part of the modeling parameters you're looking at when you're assessing the grid security in terms of resilience or fuel security, fuel assurance, et cetera.

I think a lesson is to not act and create the market design based on these political pressures. I'm wondering if folks on the panel have sort of responses as, or thoughts on where we are today, the best way to move forward. Is there an answer to what's going on in California? Is it going to differ across regions? I'll throw that out there.

Moderator: Does anyone want to bite on that?

Respondent 1: Yeah, my view is that electricity is probably the most politicized commodity in the country. And, so, you can't take all the politics out of it.

Moderator: Why is that?

Respondent 1: Well, FERC Commissioners have to go through a hearing. You're jerked up on Capitol Hill all the time to testify. We were during the California crisis and when we proposed standard market design, we had our heads handed to us. So, you can't take the politics out of it, but you're hired to do a job. You take an oath to do a job and if you know something's wrong, or you suspect it is, you need to pause and try to figure it out.

And I think FERC is facing that now in all sorts of ways since state commissions are, too. And if you're going to have markets, you need to design them well. I mean other kinds of markets perhaps don't need to be designed quite as well. Electricity markets need to be designed well to work, or they don't work at all. And the second thing is you need to protect the market from outside influences. Otherwise just go back to regulation.

That's the way I feel about it. Somehow market prices need to arise from a good market design, not from political decisions that are made along the way. And there's no way for it to be pure. It never will. Because everybody who gets these jobs are political animals. But I think the political courage to do the right thing regardless of the criticism is in short supply everywhere, right now. And I think regulators need that as well.

Moderator: Next question and then one more brief one.

Respondent 2: Because I think the reality is that the electricity policy is set politically. That's just a reality. And what we're facing going forward is basically the political community and a lot of citizens want cleaner energy, green energy and whatever else.

It's a big issue. Part of the market design is to figure out how to get stuff done. So, the market design in and of itself isn't the mission. It's like, "How do we do that? And I think at one point in time, certainly the time we were talking about, we had shifted into a more retail world and the discussion we've had today is largely OK, if we had to do it all over again, how would we have done it because we obviously ran into problems in California.

But going forward I expect this to be politically driven. And then the question is how do we structure markets based on what we know to basically meet outcomes that are acceptable? My biggest concern is being an advocate for renewable energy and everything else, is we screw it up and we have blackouts as a result of the fact that we did not plan for the fact that, you probably don't know this, but every 12 hours there's an event that happens with the sun going down.

And how do we deal with this? That's not an insurmountable problem, but it's one that in the world I live in the state capital is just assumed away. And so, trying to come up with markets

that actually work and are based upon things that we know can work, I think is very important.

Respondent 1: Economists assume it can't, California assumes away the sunset. Is that what that means?

Respondent 2: We assume storage. Apparently there's an unlimited amount of storage and everybody should have it.

Moderator: Very briefly.

Respondent 1: Just real quickly you know you brought up the one-in-10-years, et cetera, and I, just based on my experience in the industry, I would take all that reliability modeling with just a huge grain of salt going back to my early QF days back in the early 1980s. Just trying to figure out, well, what's the right reserve margin and hey, what's the probability?

So, I talked to our system planners and I basically said, "Well, how do you know it's one-in-10?" "Well, because we adjusted the models to fit what the operators felt comfortable with." And so the operators went back in history, recent history and said, "Well, I felt comfortable in 1977. I thought that we had a nice reserve margin, so calibrate all your computer simulations so that they produce a one- in-10 year in 1977 and go forward from that."

Let's be real. We are engaging in what the military calls a reconnaissance in force. That's where you have to move so fast that you don't send the scouts ahead of the troops. You just go out there and when you engage with the enemy, then you know where they are. And we're in the same process right now, going into uncharted territory in terms of ramping capabilities and how much gas can we shed, and how is solar going to work anyway? I wouldn't take any computer simulation models too seriously.

Question 9: Yeah, I just have to say something about capacity markets. Everybody seems to be blaming the competitive market. Power pools had capacity markets. I was at PICO when we

used to retroactively trade credits, capacity credits. The markets developed one. We had the energy cap problem which is why we have to have capacity markets that Speaker 1 doesn't like, but that's why.

Two, then we further developed them because it turned out, I was at that company too, PSEG gave PJM about 30 days' notice that we were going to retire a power plant and PJM said, "Oh, we have a problem. We need more than 30 days." So, capacity markets have served and evolved to meet the needs of the systems planner and reliability. And to give it back to the states is to take away a very important planning tool, an economically efficient tool that has evolved to meet the differing needs.

You can call it whatever you want going forward, but this morning one speaker told us, "You are going to continue to have to have resources that have specific characteristics." You can call it capacity, you can call it ancillary services, but at some point this "administrative revenue stream" is going to have to be there to keep reliability.

Session Three.

Utilities on the Customer Side of the Meter: Issues and Challenges

Market penetration of demand side management, demand response, and distributed generation, on the customer side of the meter, may well be the fastest growing business opportunity in the industry. That growth is in remarkable contrast to the lack of substantial growth for traditional regulated utility activities. The contrast has led many utilities, both vertically integrated and distribution only, to consider increasing their presence on the customer side of the meter. There is an element of déjà vu to this, given that many electric companies had been engaged on customers' premises from the beginning, including selling (even giving away on occasion) appliances, providing electrician services, and, of course, running energy efficiency programs. Some of those activities, have, for a variety of reasons, fallen by the wayside over the years or utilities maintain demand side management programs without earning a return on those efforts. Utility managers see many new actors providing services on customers' premises, and this is an opportunity for their companies, a natural fit given their knowledge and relationship with the customers. Many of the strengths utilities possess may be more of a barrier than a facilitator to entry. There are many players in the demand side space. They see that market as highly competitive, a status that would be heavily disrupted by the entry of the local utility. Furthermore, rapid technological change requires innovation and adaptation, as well as risk taking that has not been characteristic of the culture of heavily regulated utilities. Thus, many non-utility players in the market contend that those actors best equipped to operate and innovate in the market would be at a competitive disadvantage to a player less equipped to do business in the space. Would expansion of regulated utility activities on the customer side of the meter enhance efficiency or stifle innovations? Should such activities be treated as regulated or unregulated businesses? How can regulators strike the right balance?

Moderator.

Good morning, everyone. Let me just briefly go through the ground rules again, for those of you that weren't here yesterday. The ground rules are fairly simple, that everything is not for attribution.

There will be a rapporteur's report. But the rapporteur's report will capture the substance of the discussion, but no names will be mentioned. In addition, after each panelist makes his or her presentation, we'll take clarifying questions for that panelist, clarifying only. And then when the entire panel's done, we'll take a break, and after the break, we will open it up to discussion, substantive questions, and whatever you want to talk about. And put your name card in the vertical position if you want to be recognized, and then I'll call on people in the order that I see them.

So this morning's panel takes a look at what the role of the utility is on the customer side of the

meter. And obviously that includes a broad array of demand-side resources, including self-generation or rooftop solar, for example, but it also includes all those kinds of services. And there's two fundamental questions which are raised in the panel description, which the panelists will address.

One is a question, somebody described it as an anthropological question. That is, since utilities, because of their regulatory environment, are trained to be risk averse, and the customer side of the meter involves a lot of changing technology, rapidly out, basically technology that gets depreciated in terms of its usefulness more quickly than the physical asset. Are utilities, either culturally or from an economic incentive point of view, best situated to do that kind of business? Or does it require more of an entrepreneurial mindset. That's sort of the anthropological question.

And then there's the antitrust question. One of the things that's fascinating about the electricity industry, if you go back in history, is the early utilities sold appliances. In some cases they actually gave away appliances just to get people to use electricity. And that raised a lot of, if not antitrust, certainly competition policy questions. And we're trying to frame this broadly. So it's not meant to fit in with the arcane concepts of antitrust law, but to fit into a broad sense of competition.

And then, of course, the utilities have access to customer information in most states, if not all states that control the meter. They have a long history of relationships. So the power of the incumbent can be quite strong, and what's the effect of that on competition policy when the utility is engaging in business. On the other hand, utilities, when they see flat revenues, or in some cases declining revenues, may be looking for areas where they can grow, and obviously the customer side of the meter is one of those options. So that's the broad contours of what we want to talk about. Speaker 1, who comes from the customer services industry, and will talk a little about where he sees things going, and then when he's finished, then Speaker 2 will talk from the standpoint of what they're doing from a utility perspective. I don't want to stereotype you, but that broad perspective. Then Speaker 3, who's worked a lot on these issues, will talk from a broad policy point of view and experiential point of view. And then our cleanup hitter will be Speaker 4, who's going to talk more about the competition policy issues. So Speaker 1?

Speaker 1.

Thanks. I think I drew the short straw, and you get me first, the comic relief of the morning. So I'd like to tell you a little bit about myself. I'm an electrical engineer, power engineer by training. My first job out of college, I began working for a utility and then quickly was

transferred to a utility holding coming providing these very services of efficiency service out to industrial and commercial clients. And then I decided to switch over to a private company, or so I thought a private company. I joined a firm that was an energy service company, providing these services out in a more broad sense, only to find out after I joined, it's majority-owned by yet another utility company. And then I worked for that company for several years, and then lo and behold the owners bought it out, and then we were bought again by another utility holding company.

So I've had a little bit of utility holding companies in my background, but doing energy services for most of my career, left that job and went to work for the US Department of Energy, where I ran a program called the Federal Energy Management Program, managing the energy efficiency of all the federal government's buildings. Before I left that, I became the deputy assistant secretary of renewable power, so for two years, under the Trump Administration, I did all of the renewable power research of the Department of Energy and managed that portion.

Then I left that just a year ago and became the executive director of the National Association of Energy Service Companies, a trade association that manages the industry that does energy savings performance contracts done by ESCOs, energy service companies. We do performance-based contracting in this industry. We come in, and we do the energy retrofits to make buildings and infrastructure improve in operation, and we use the savings we achieve from that improvement to pay for it.

Usually there's a bank or a financier behind the deal that comes in and provides the money, and then the energy service company will measure and verify the savings for often 10, 15, 20, up to 25 years for federal government. Most projects

run around 20 years of the projects installed. And then that savings will pay down the note over that term as well. This industry is primarily done on public buildings, so federal government, state government, cities, counties, universities. Hospitals get involved in it as well. And it does require specific legal allowances for us to do this work across the country. There has to be laws in place in each state and in the federal government for this to be enacted.

The industry size overall, based on the last Lawrence Berkeley National Labs study, is about a \$7 billion annual industry across the country. It is growing internationally, but the international markets struggle at times with how they recognize the debt that's accumulated based on these projects, especially in Europe. They're challenged with it, but some of those laws are also changing. We're seeing some growth internationally as well.

Our market is also changing with new market entrants. We see changes with the way the work is done. A new type of service called energy as a service, where today my companies will do the work, and the equipment immediately becomes the ownership of the customer. New entrants are coming in and taking ownership of that building equipment, owning the boilers, the chillers, the air handling systems, potentially even the lighting systems and control systems, intricate small pieces within a building they'll own separately and operate and maintain, and then sell the overall service out of those components and equipment and energy into the building as a service, providing their operational needs.

So as I look at the efficiency world, we're talking about energy efficiency. We're talking about services going into the customer side of the meter. I see that it's changing. While I was at Department of Energy, the policy always was that you did energy efficiency first. You did as much

energy efficiency as you could, and then you began to install renewable power. There were two primary departments, the office that ran energy efficiency, and mine that ran renewable power. They were always butting heads over which one should get priority. Perhaps you've heard of it in California, some of the issues with the homebuilders, where they have efficiency requirements for the homes for more insulation and so forth, but perhaps the standard for carbon reduction could be met also with solar panels.

And it turns out the builders have found that those buying homes would rather see solar panels on their roof than more insulation in their walls. It helps the home price. They can get more money out of it. And so there's a battle between renewable power and efficiency right there in the state of California in the residential market. And that continues today. I've heard some argue that if we have a grid with more and more renewable power, and the power's all green, why do we bother with efficiency? If all the power is green, what does it matter how much we use? Our carbon is still neutral in that case. And I've heard those arguments as well.

Well, one of the things that I believe is, as I was at Department of Energy, I ran an effort called the grid modernization initiative. And it was my glory days to get back to my beginnings as a power system engineer to get more into grid design, development and research, and it becomes clear that renewable power that we call solar and wind is really only about 7% today. 1% of that's about solar, and the remainder is wind. Now, wind is growing very rapidly. Wind just recently became larger than hydro as the largest renewable power in the country. But when we look at the grid with those types of sources, it's a different operational paradigm than what we have today.

We all understand today, most of our power today, even still, comes from fossil-fuel generation and nuclear generation. And those are old generation types that we think of as stable power. They come from big generators that we can control, and we can dispatch, and we can impact how that power is generated and distributed on the system, to new renewable sources which are somewhat dependent upon the environment of which they exist, and our ability to control those is often challenged.

And another piece of that that us power system engineers talk about is what we call grid services. They're these other things that are part of the grid operation that are beyond kilowatt hours and kilowatts, such as voltage support and frequency support, that are very critical to good operation. As we installed, in the history, the big fossil generators, these big induction machines is what we call them, these grid services came with the kilowatt hours that we wanted, too, badly. When we installed the new renewable type systems, we get these kilowatt hours, but the grid services that we've grown to depend upon that came free with the other systems don't come with the renewable power systems. The renewable power systems, solar and wind, are often fed through an inverter, through electronic devices into the grid, as opposed to directly from an induction-based generator, which is what we have on the grid today.

And that poses changes in how we have to operate the grid, and changes on how we understand the grid operates. This is a simple example. We all have homes where we have circuit protectors in our house. We put too much load on the circuit, we run the vacuum, and then we run the microwave, or we run the TV off of one circuit, and all of a sudden it trips. And the reason it trips is because too much current flowed through there. Our power system today is built with the same type of protection you see on the poles. When too

much current flows, those things trip, and it's because the generators that we use today have the ability to supply an infinite amount of current, theoretically, which causes those things to trip.

When we switched over to an electronic supply, like solar and wind is, the circuit no longer has the ability to send as much current as is needed to trip those, and so when a wire falls to the ground, it just continues to send electricity into the Earth and never trips the circuit breaker. We have to have a change in paradigm of how the grid operates to handle such strange circumstances and the physical conditions that this presents to us.

So when I look at efficiency, our grid is not prepared to handle a full renewable slate of power. Now, I think my own state, Virginia, says that they want 30% by 2030, and 100% renewable or fossil-free generation by 2050. And so that's 30 years from now. And we think that our grid that we're getting power from today, some components of it might have been built about 50, 70, 80 years ago, and we're still using it. And it represents technology of 50, 70, 80 years ago. And so as we look at this grid, it has to change in some way, shape or form to handle a more dynamic load, and handle a more dynamic source, which is something we have not experienced.

Today we think of our dynamic wind and solar that constantly change up and down, the power goes up and down, and we think that's not acceptable. But our load has always changed up and down. Our load has always been dynamic. We've even developed programs to try to flatten the load in the daytime to better match up to our generation. And now what we're talking about is throwing batteries everywhere to try to make this new type of source flat and level like the old one used to be. My vision of the grid is that the grid will be a dynamic marketplace, and these grid

services that I talk about that are so elusive will be supplied by many different places, from the batteries, from the generation, but also that can come from the load side.

And I think that's where efficiency plays a role. Efficiency becomes important because we need these things to control the grid. Batteries can do a lot, but they can't necessarily do everything economically. I think we're just now entering into the age of batteries, getting large scale battery installations. We don't necessarily know how those will perform over long periods of time. What environmental impact those will have, and so we need to think about how we can supply those grid services otherwise, as well. We call it smart buildings. I call it efficiency. Efficiency and smart building go hand in hand. When we do an efficient retrofit today of a building, we don't expect the building to get worse. In the '70s, when we did energy efficiency, we expected to be cold when we wanted to be warm, hot when we wanted to be cold, and we thought it should be dark when we wanted it to be light.

That was efficiency in the '70s. Today, efficiency means we expect the light to be better, the building to have better indoor environmental conditions, and we expect it to be better temperature controlled. So we expect more out of our buildings when we do an energy efficiency retrofit. In many ways, the smart building movement is what we see coming in, and really what smart buildings are, are efficient buildings, and those smart buildings will be able to provide these grid services back to the grid to help balance out some of this renewable power fluctuation that we see happening today.

And then there's also this crazy idea of resiliency that comes in, and I think what we'll find is that efficient buildings and the smart building control are what we're going to need for resilient

buildings. And so that's where I see efficiency flowing today and where I see it going.

Moderator: OK, thank you. Any clarifying questions? So, Speaker 2.

Speaker 2.

OK, good morning, everybody. I am a manager of customer technology, product strategy and development. My team is relatively new at my utility, and we are very uniquely situated to do some of the things that we heard Speaker 1 speaking of, and I really view my team as the bridge between what our customers want and what our system needs, which is kind of a different approach to how we've engaged with customers before. We used to always start with reliability and system needs first, and we're kind of flipping that now and starting all of our engagements with our customers with what are your challenges, and how can we help you solve them and identifying mutually beneficial solutions that meet our customers' needs and also provide value to our system?

So that's the lens through which my team looks and works, and so that's kind of the context for my presentation here this morning. So this is a quick snapshot of my utility so far. We are the largest utility in the state of Arizona. We serve 11 of the 15 counties in the state. This slide is a little bit old. What I will say is, when this was put together at the end of 2018, we were already more than 50% clean. We were the second utility in the nation with regard to residential solar customers, and a little bit over 1.8 gigawatts of total renewable capacity.

That's only continued to grow. In fact I was sharing with the Moderator earlier that in August of this year we hit our 100,000th solar installation on our system, and we were over one gig of solar across our system, and that includes all residential solar utility-scale solar and APS-owned solar. So there's a lot happening in our state. And we'll

talk more about some of the other things on this slide.

Let's dig in a little bit more on the distributed market here. You probably have heard that the value of solar was a drawn out discussion in our state, as it is in others across the country. In fact, that's how I got to meet the Moderator. He testified in that proceeding for us. And we were told that what was being discussed at the time was going to kill the market. And that our rate case that happened just on the heels of the value and cost of solar proceeding would be even more detrimental to the market. And that's not what we're seeing bear out in reality.

Despite what the commission found in the value and cost of solar, and subsequently what was approved in our rate case, we continue to see mass adoption across our service territory. So this just represents of all the solar in Arizona, most of it is in our service territory, which makes sense, given that we're in most of the state. We see more applications per month on average than all of the other utilities and co-ops combined. So there's quite a bit of activity continuing in our service territory. Again, we are ranked second among the largest utilities in residential solar penetration, and we keep seeing more and more of that every day, which helps us kind of look at how do we incorporate different solutions to help manage and integrate that generation successfully into our system.

So diving in a little bit more into the value and cost of solar, one of the outputs of that proceeding was what was called the resource comparison proxy. We didn't end up at the end of the value and cost of solar with an avoided cost methodology. That's still to be determined at our corporation commission. But the RCP is a calculation that was a methodology that was determined through that proceeding, and it has an annual step down of up to 10%. And even post-

implementation of the first tranche of our CP, we continue to see increased in applications. In August of 2019, we actually received over 2,900 applications.

So we continue to see a significant adoption across our territory. Regionally, our resource needs continue to change. Our peak loads continue to grow. Our state is a place where people continue to move to. We are, if not the first, we're the second largest county, in Maricopa County, which is where the Phoenix metropolitan area is located. And load does continue to grow for us, so that peak hour over summer continues to be a challenge.

Meanwhile, the winter net load continues to become deeper as well, because of all of that solar that is being installed across our service territory. So again, that problem just keeps getting worse. I'm not taking a position on what a renewable goal should be. But as we look at how do we become a more carbon free society, and how do we look for new ways to reduce carbon across the board, this just is illustrating that as that renewable goal alone continues to increase. You have to produce more than three times your customer load in that period, and that operationally is obviously a challenge.

I wanted to talk a little bit more about solar overproduction. We are obviously located very ideally on the footsteps of California to our west. We're seeing increasing numbers of curtailments across the region, and we look very closely, on an hourly basis and an intrahour basis, to try to maximize those opportunities when solar curtailment is happening across the region, and we can bring that into our system and maximize that on behalf of our customers.

We are a participant in the energy imbalance market. Earlier this year we made an announcement that we were going to be investing

in up to 850 megawatts of battery storage by 2025. That is a commitment that our company is still very much working towards.

You might have heard about an incident that occurred at one of our utility-scale battery storage facilities earlier this year, where unfortunately there were some injuries. So we have not continued to execute on any of those contracts until that investigation finishes. We want to make sure that if there are any lessons to be learned from that event, that it's applied to any future projects. But, nevertheless, it is not derailing our commitment to that 850 megawatts by 2025. It's an important part of this solution.

We have a variety of ways that we're working to deliver a clean energy future for the state of Arizona and our customers. It's a combination of everything from modern rates that we worked towards in our last rate case, which we'll talk a little bit more about in a moment, to distributed and utility-scale solar energy storage, like I just discussed, and then we'll talk later about the rewards program and demand response and how we see that growing in our service territory, as well as microgrids and transportation expectations.

So at APS we have one of the largest time-of-use programs in the country, and following our last rate case, which was approved by the Arizona Corporation Commission in August of 2017, the number of customers on a demand rate, a three-part demand rate, has more than doubled. And we are seeing actual behavioral changes as a result of those rates. We're very excited about the potential benefit to the grid from these more modern rates. They're obviously designed to encourage our customers to shift their load outside the on-peak period, when it's cheaper for energy to be produced or procured. And it increases the opportunities for us to deploy DERs and DR across our service territory.

A little bit more about those observations I was just talking about. This graph or chart, rather, depicts the 2017 load profile as compared to the 2018 profile. While that's meaningful because our rate case was approved in August of '17, we were trying to show year over year comparison. The change, getting into the on-peak period, has gotten even deeper. There are days where you can see drops heading into our on peak period of 60 to 80 megawatts and sometimes more.

But there are real behavioral changes. Now we're also trying to focus on what happens when we get to the off-peak period, and we start to see a little bit of snap back, especially when you can combine a DR then at the same time. So we'll talk a little bit more about that. Our rewards program came out of a demand-side management plan that was approved by the Arizona Corporation Commission, and it was designed to try to maximize value for our customers, as well as balance that against the operational changes that our system was seeing. It had a horrible name at first, and it was rebranded "the rewards program." Our engineers named it something like Dreslem, and nobody liked it. We got yelled at at the commission. It was horrible. So now we have marketing involved in all naming.

It's called the rewards program. We'll talk a little bit more about that. There's three components, really. The core rewards program, which is our smart thermostat program, there's actually a typo on this. We now have over 16,000 smart thermostats that are enrolled in that program. And this summer was the first complete summer where we ran this program, and we'll talk more about some of the results from that.

But there are all kinds of benefits that can be realized from a program like this, which I'm sure you're all very familiar with. Not only can we reduce load, but we're also testing precooling as

part of this program to see if we shift some of that load into the off-peak, what that does to the customer's rate at the end, or during the on-peak. We also have the reserve rewards, which is a connected water heater program. We have about 300, I believe, is where we're targeting to end up, but these are all, actually, if I could go back, we were recently jointly awarded the CEPA Innovative Partner of the Year award with Energy Hub for this program. So we've partnered with Energy Hub to establish our resource operating portfolio, and so all of the connected devices that our customers opt in to participate in the rewards program are operated through this resource operating platform. All of the water heaters are also connected to this system. We also have a storage rewards component.

We only have about 40 batteries. These are residential batteries. They're mostly residential. There will be a couple of commercial customers. But these will also be controllable from the system. So we've run a couple of different types of events with our cool rewards programs. We've attempted to test the effect of the precooling with the reduction heading into the on-peak period. We've also tested some firm load dispatch, to see how they perform, compare and contrast, and trying to also get more intelligent about locationally how can we dispatch some of these resources in order to add benefit to the system.

With regard to the rewards program, we are already seeing pretty significant reduction. We did have an event earlier this year where we saw over 18 megawatts of reduction, that was a sustained reduction. And so for us, we are all in on the rewards program, and thinking about what's the right incentive level for customers to participate in that, so we can get kind of line of sight and visibility to those connected devices in our customers' homes, so that we can, to Speaker 1's point, as situations happen on the system, that we can respond to them more timely. Events

happen all the time. You do a plan for an emergency.

The dynamic nature of these resources is really where we want to get. What does the future hold for us? As I talked about earlier, we are very uniquely situated in the way that we get to engage with our customers. We're very much committed to transportation electrification. Maricopa County is non-attainment, and it is going to be important for us to really get to a significant level of adoption in not just Maricopa County but in the state of Arizona. We're also a transportation corridor to our neighboring states. So we want to make sure that we are establishing a good infrastructure that people can rely on when they're traveling through our service territory.

Earlier this year we kicked off the Take Charge Arizona pilot. That is level two, level three charging, but we're excited about getting that out, partnering with some of our customers, and seeing how they actually interact with the charging, how we can effectively leverage managed charging. So we're really just starting to dip our toe into the water a bit here in the transportation electrification space. We're very excited about it. The expansion of the customer facing demand-side management and DR programs, over the last couple of years, our DSM program has really shifted its focus to solely peak management, or mainly peak management. While that is still important, we want to make sure that we are actually delivering on what customers want. We know that customers want, most customers, or some customers, want those cool technologies that they can interact with, and they want a deeper experience than they have traditionally received from their utility.

And so we're looking at ways to do that through our DSM program, and then also exploring with various potential partners on how we can leverage AI to get better messaging to customers,

so that they are receiving the information on how to be successful on those more modern rates that we talked about earlier. Some people are very easily open to those more modern rates, and some people struggle with that. And so we want to make sure that we're making it as easy as possible for all of our customers, and that we're delivering in as real time as possible information so they can make actual changes to be successful on their rates and with the technologies in their homes. OK, that's me.

Moderator: Speaker 3? Oh, I'm sorry, question?

Question: How does it work with, is there any pricing response to deciding when to implement these? Or is there time-of-use pricing at the customer meter as part of it? I mean, it seems very innovative in terms of use of the technology. But I'm curious about the integration of what's going on there with this program and the actual wholesale market and what prices are there.

Speaker 2: That's an excellent question. We're not there yet. But that's where we want to get. I will share part of my background at the company. I ran the real-time trading desk for several years. And so I want to get us there. I want to make sure that we're delivering customers information. So for example, if our neighbors are pushing us tons of negatively priced energy, I see a future where I'm signaling to maybe a large commercial customer, this is the right time to charge your car. Charge your car right now. Right? And so we're not there yet. But testing these technologies and the way that we're doing and bringing more connected devices into our resource operating platform is how we're going to get to that eventuality.

Moderator: Any other? Yeah.

Question: You had, two or three slides back, you said, it said that you allow customers to override the peak events without penalty.

Speaker 2: Yeah.

Questioner: Can you explain a little bit more about that, what that means?

Speaker 2: Absolutely. That is all about customer experience. So all customers have to opt in to the rewards program. They receive a \$25 incentive, for example, to opt in to the program, and then they will receive a \$25 bill credit for every program year thereafter. But we want to make sure that customers still have control over their homes. We don't want them to feel like we've just taken over control, and they no longer have autonomy in their homes. And especially in Arizona, that's very important. Arizonans do not like to be told what to do. [LAUGHTER] God love us.

But we have the lowest opt-out rate across the country, according to what Energy Hub is seeing with their other clients. So even though customers have the right to still go and change their thermostat back to what setting they're comfortable with, we're not seeing that happen a lot. But there's always going to be those potential for circumstances where we've decided to execute an event, but maybe somebody's having a book club, or they have family over, and they want them to be comfortable. And even though we're only changing the thermostat plus or minus two to three degrees, that means a different level of comfort to some people. So we want to make sure that they understood that they still maintain control in their home.

Moderator: Speaker 3?

Question: Yeah, I just was curious about the residential battery arrangements. And I don't want to get too deep in the weeds, but some of my questions are deeply institutional. Like, for instance, does the residential customer own the battery? Does the utility own the battery? Can the customer operate the battery? Is it just a

convenient location to stick a battery so that the utility can operate it? And also, roughly, how large are these residential batteries?

Speaker 2: I don't know the answer to the size. I probably should. I should also probably share that until approximately two months ago, I was in regulation. So I didn't have to know the details. I'm still getting caught up. But the customer can operate it. They were chosen for their location for the most part. We reached out to constrained customers on constrained feeders to try to make sure we were putting batteries in places where it would be most beneficial to the system. But the customers would still also be able to control. So both the utility and the customer could control the resource. But I'm not sure about the size.

Moderator: Other clarifying questions for Speaker 2? OK, we'll turn to Speaker 3.

Speaker 3.

Hi, everybody. I'm with IPP Connect, a small consulting firm. The Moderator and I have in the past worked together for about seven years with the Galvin Electricity Initiative. As part of that program, we were looking at policies from around the world and prototyping microgrids and projects that brought utilities and the private sector together to see what could be done to help transform the electricity sector. And I think that program revealed that the FERC, the ISOs, working with the states, working with the utility, working with the local governments, the local community side, really all coming together is something that could help. So today I'm going to talk a little bit about how utilities can transform themselves by focusing on their distribution systems. [INTERRUPTION]

Comment: Sometimes on the customer side of the meter, things don't work. [LAUGHTER]

Speaker 3: So the first thing I'll pose to everybody, and the Moderator asked me to be a

little bit challenging, is, as we talk to the utilities, I think what we're learning is they all agree the behind-the meter-market is lost. And when we listen to most of the utilities, it's about facilitating this marketplace, not necessarily participating in it. Because you've literally got trillions of dollars, the biggest companies in the world designing and building and innovating all kinds of new technology to get behind the customer meter. And I think from a utility perspective, it will be very difficult to do anything but facilitate what's going to happen behind the customer meter.

So we spent yesterday talking a lot about electricity restructuring, and about half the market, in terms of megawatt hours, is restructured, and about half is not. But those markets that did not restructure face huge challenges in terms of getting to the zero carbon goal and stranded assets. So in a restructured market, if I build a plant, and you build a more efficient plant, you push me right out of the market, and I'm gone. In a regulated market, that's a stranded asset for the next 20, 30, however many years it takes to pay that asset back. So as we try and get to zero carbon, the regulated markets become a barrier to that, because you've got these assets.

Now, Florida Power and Light's making huge progress, and as we heard on the solar end for APS, they're making huge progress in certain areas, like gas for Florida Power and Light. But it's still going to be a huge challenge for them, because they're building more assets and spending more money. And so I think it's going to really impact the price. And what we've seen is, the price in regulated markets is rising much faster than restructured markets. And I think price usually forces regulators in one direction or another at some time. As you reach limits to what the customers can bear.

But I just wanted to show you quickly, I was actually listening to the FERC chairman, John Norris. He's no longer the chairman anymore, but he was speaking at a conference. He came from Iowa, and he's really proud of the fact that he fought restructuring and stopped it in Iowa. And so I had to get on my computer right away and go, well, what the heck did pricing look like between Iowa, Illinois, which, Illinois is the only restructured state, and those are all the states in the top there that surround it? And I just had to go look and see, but what happened to pricing during this period, since restructuring really started?

And you can see, it's Illinois, they've added some high distribution. ComEd has got a lot of programs going on right now, smart grid, etc., that's added a lot of price to the distribution, but even with ComEd increasing their rates significantly, you can see the overall price didn't move that much. This is not adjusted for inflation. But it's quite a stark contrast. And I just looked at the large regulated states, versus the large unregulated states, and you can see a pretty stark contrast with the big states, what's happening. I think it means that it's an important time right now. And I think some people here have talked about, we're at an inflection point, and I think Speaker 1, you said it very well, this inflection point is that utilities need to get focused on their distribution systems. They need to be able to handle what's coming, and facilitate it and support it. Because it's coming. It's just there's no stopping it right now.

And so that's what I'm going to talk about today, is how do we do that? How do we help the utilities grow by focusing on what is their core business? I'll start by saying, our entire government is set up through a federal level, a state level and a city level. I would argue that as the utilities bought up all the municipalities over the last 60 or 70 years, we've lost the local

involvement in our power system. And it's a critical component that we're missing.

What I see coming in the future is that we'll be adding the local component to the grid, and I'm suggesting that the utilities that join and partner with their cities, bringing the FERC and the ISO along, to prototype and build and design the system of the future, are the utilities that will succeed going forward.

And so what you see coming, from my perspective, is both utility microgrids, and embedded in those utility microgrids will be private microgrids. And I'll give you one example. We're working with a utility and a regulated state, and a huge developer. This happens to be in a disadvantaged area in the city. And we're building a microgrid that's going to be roughly split. So the utility's going to own the microgrid on half the property, and then where the owner owns all the buildings on the other half, we're going to build a private microgrid. There's going to be solar on all the buildings owned privately, and the microgrids will be able to be connected. We'll have switches that will allow the private microgrid to actually island the entire facility.

It's \$35 million of investment and about seven megawatts of solar, four megawatts of local generation, all the site distribution for the private sector side, and the utility will probably have to invest about 10 million for all their electrical stuff. Well, for the 35 million, between TIFs, opportunity zone credits, tax credits and depreciation, not even counting depreciation, actually, we've got \$27 million in incentives on that microgrid. So here is now the utility working with the private sector to create this much more sustainable development, leveraging all of the tax credits that the utility would not be able to take advantage of. And it just shows an example of how working together you can have a completely different type of project built than you might have

had if the utility had just supplied power to that whole site by itself.

And we've worked on a number. Right now you've got Exelon, ComEd working with the Brownsville microgrid, and that looks like it's going to be a private/public partnership between maybe the local university and Exelon, where the university will build extra generation as part of a boiler upgrade, and will supply the power whenever ComEd needs it, to isolate an island, a substation. So what you really see here is at the local substation level, all kinds of new things.

But it requires piloting, prototyping. It requires bringing the ISO and FERC together, because as I'll explain, there's a lot of moving pieces when you're trying to do this. So what is the role of the utility of the future? And I think defining yourself as your objectives, what you're trying to accomplish, two-way power flow, to support the renewable power and transportation sector. As Speaker 1 said, right now we don't have that. We have a lot of parts of our grid that are still fused. They can't even take reverse power flow. They can't even take, really, much of any distributed energy on the circuit. We need to deliver power to the electric transportation sector as it grows, and projects can go anywhere from 10% to 30% that might add to the electricity system. And I get *Ricardo*, which is the transportation magazine. It comes out quarterly. And they're the transmission. They really drive the transmission side. Well, Volvo is moving to a complete plug-in hybrid basis. In about five years, you won't be able to buy a Volvo that isn't a plug-in hybrid car. Ford's going to have a complete line of plug-in electric hybrid vehicles.

And anyone you know that owns one only, even though it's plug-in, and even though it's hybrid, they'll only put a couple of gallons of gas in a year, usually, driving around a city. So I think the transportation sector is going to move much faster in this direction than even some of us

anticipate. We need to manage the distribution system in real time, which to me tells me we have a distribution ISO coming that will work with the PJM, the ERCOT, what I'll call the regional ISOs. They'll become tandem partners, but the distribution ISO's going to manage the power quality and the immediate response locally. But they need a whole bunch of assets behind the meter in order to do that. And that includes gas-fired generation.

Now, gas-fired generation will be used differently. It will be used more for demand response. Diesels will pretty much be gone. And that will all be replaced by a gas-fired infrastructure, because that will give you a little bit longer response if you need it. So, if you needed for three days during a huge outage, or maybe a week during a major outage for the grid, you could still run the entire microgrid locally using that gas-fired generation, the solar and the other aspects that are there. But, normally, that gas-fired generation would be used for price response, with batteries, whenever they make it economically, which right now they're not.

And we do distributed energy studies. Literally, I've done them in almost everybody's territory. We run all the different technologies, and I can tell you, we have not found a project yet that could work on batteries, at any rate what's out there right now. So building a high reliability distribution system, and I'll show you what that is, managing power quality, providing for resiliency at the substation level, are really to me what the, so now I'm going to talk about how, and I'm just give you some concrete examples.

And I'm just going to walk you through this. So first is what I call microgrid mapping, and beginning to build. And this is Westchester County. But what you can envision is the utility pretty much looking at their substations, dividing their whole territory up into a network of substations. In many cases what you'll find is

those substations serve cities. And now they've created a situation where they can begin to partner with those local cities, to begin to build out this distribution system of the future. But it requires dynamic rates.

I'm going to give you one example on dynamic rates. The only utility I have found in restructured markets that, raise your hand if you know another utility, because I'm very interested in talking to them, because I'm working with a large property owner, and we're trying to change how they portray power across the country, as well as use distributed energy as a lever to do that, to get cheaper power. And what they're looking for is getting access to real-time price markets. Well, if you're below five megawatts, I can't join the PGMI cell, or it's hard to do. So I'm looking for real-time price rates. And ComEd was the only one I could find that had one on their books. It's one of the most effective things you could do as a regulator, is to get your utility to offer a real-time price rate, and so that the customer at least had a choice to leave the retail supplier and go to that real-time rate.

That's really important, because the innovators out there will then find ways for that customer to leverage that rate and lower price and allow your customers to gauge against the retailer providers and have an option for that. Demand charges are extremely effective. ComEd has a very effective demand charge right now. It's from 9 a.m. to 6 p.m. It's a fairly high demand charge. That, combined with the PJM capacity charge, and then moving to real-time pricing, gives me the paybacks I need to be able to put distributed energy in.

Now, once that distributed energy's paid for, you could change that demand charge. You could shorten the period. You could go to a dynamic demand charge, where the distribution utility's calling on me, just like the capacity charge, which would mean I wouldn't run as much. You

wouldn't necessarily have to give me as much money on the demand charge of savings. So utility could take more back.

Once the infrastructure's built in terms of behind-the-meter assets, the rates can change, so I see the rates changing dynamically over time. But they start with more firm pricing, and then they can move to more like a capacity charge. Of course, some are doing demand response payments. And we're doing some projects right now with utilities looking at substation. And I'll give you one example. We're working with a rural utility that's got six or seven substations. It's going to cost them \$20 to 40 million to run a new line to cover those substations. They can't own generation, because they're in a restructured market. So now we're looking at, well, could they lease the generation from a supplier at the substation? They lease the land and lease the generation back, maybe under a cap, though we're not sure that's possible. That's what we're looking into now.

But the community choice aggregator right there could then leverage that generation to go into the real times and save a tremendous amount on their real-time procurement, I'm sorry, on their aggregation for the local community. So again, it's a public/private partnership that could bring that all together. But what do you need to start with?

So after I finished working on the Galvin Electricity Initiative with the Moderator for about six years, we had built a, working with a team of industry leaders, the first ever PEER. It's called PEER. USGB now owns it. We sold it to them, the Galvin Electricity Initiative did. And it's the very first international standard for electricity systems. And it provides you with a comprehensive set of metrics, and you can get rated to it. You can just use it as a standard for developing your microgrid. A utility could use it. Chattanooga is certified to it as a municipal

utility. Naperville used it as their scorecard for their program.

And it's being used internationally now in India, and I think three other countries. So, we're getting slow adoption on it, but it is out there, and it's available, and it's the first really independent standard, like LEED. It's kind of like how LEED is for buildings, PEER is for the energy distributed to the building. So now we have the full package covered in terms of energy delivery to the building. But what you see here is a set of comprehensive metrics that you can use now to measure performance and drive your strategies and your tactics for how you're going to get there.

I've talked about self-healing distribution and why it's so important. This was the city of Hinsdale, again in Illinois, ComEd's territory. They had two substations feeding their main downtown substations, with the hospital on the substation, all kinds of things. But you can see, it's fused going out to the customers, and it had no disconnect for the two feeds. So actually, even though you see two feeds coming to this, if there's a fault anywhere along that line, it takes out the entire substation. All it took was putting in two smart switches. These smart switches cost like \$200,000. They're not very expensive. But now with the two smart switches at the substation level, we can isolate the two area substations, and this eliminated outages for this city. The city was experiencing, because it was all trees all along that. It was all overhead, very bad. Now what you see on the right side is, we've looped the circuit. We tied it together on the right side. And we put smart switches all along. Now we have a high reliability distribution system. We can move the open anywhere onto these two loops. We can now isolate any faults immediately.

These switches talk to each other, and they isolate immediately. Chattanooga and Naperville have both built these systems. They have complete high reliable distribution systems. Naperville

essentially has no outages, because they're also underground. Chattanooga has gone from SAIDIs in the range of I think 200 to SAIDIs down in the 50s. And Chattanooga sees a lot of tornados, a lot of problems. They're all overhead. But it's just amazing what they've been able to do.

However, they're stuck now. They can't do anything else. They build this Ferrari, I call it, of a distribution system, but Chattanooga is completely locked by TVA. No customer can put anything behind the generator without TVA's approval. Naperville, same thing. Naperville's in a 60-year agreement with the Illinois Municipal Energy Association. They bought into a coal plant in 2005 when gas prices were high for 50 years. It's this huge coal plant in Southern Illinois right now. It's supposed to be clean plant. It went in, it came in way over, so their costs went way up on the generation side. However, Naperville delivers power for much lower than ComEd on the distribution side, yet they have this incredible underground, no power outages, you don't even see a wire in Naperville.

It's really to me the future of an energy system. And I think we don't think in scales of time. If you're a distribution operator, you're going to be there for the next 100 years, no matter what anybody says about all these distractions, I call them, about, we're going to lose this, we're going to lose that. It's just, what's going to kill a utility is their city, not what's happening on the technology side. If your city dies, your utility dies. That's just the economics of this whole thing. So if you're with cities that are growing, you're growing. If you're with cities that aren't growing, you're losing load. And that's pretty much fundamentally how it's going to move.

But the bottom line is, these two utilities are now trapped. They can't do anything else. And that's to me what's wrong with the regulated market, is that the generators always want to protect their

generation. Usually at all costs. And their programs will be designed to really not, even though they're trying hard, it's just very difficult. You can go so far, but you're going to run into limits as to what you can do without restructuring. This is what the looping looks like, just from an aerial view. You had all these radial lines going into the distribution system, and now they're all looped in their smart switches out there. It's fairly effective strategy. It works. Chattanooga's done it. A bunch of other utilities. Florida Power and Light is doing this right now throughout their whole system. In fact, S&C Electric built a whole factory down in Florida just to make and supply the switches for FP&L's program. It's a great economic story.

Next is protecting critical facilities. So we've done a city scale plan with a utility, and we identified all the critical facilities, what circuits they're on, and then developing strategies now for how we help them get more generation so they can island to protect those critical facilities, and looking at substation islanding, also. Eventually, once we get enough generation behind the customer meters. So leveraging the local government. Illinois has one of the most incredible riders I've seen anywhere in the country. It's called Rider LGC. If I were a distribution utility, I'd be fighting for this. What a Rider LGC allows is for the city to specify an investment, and it gets charged to their rate payers.

The only problem with Rider LGC right now is it has to be paid back in one year. We've been advocating for that to be a longer term payback. Let it be five, ten, 15 years that the utility can charge it. This puts the city in the game in terms of building an electric system that will help them grow, thrive and survive. And so this was a case where the city and the utility came together to build a long-range plan, a 100-year plan, for how their distribution system was going to transform and how the utility, the city will help pay for it.

And the city recognized that investing in the grid was an important part of their sustainable future, both from an economic perspective, as well as sustainable goals. But I've not seen Rider LGC anywhere else in the country. Coordinating underground work with road and sewer work, it's something we just don't do. Cities are constantly tearing up their roads, and we're never putting conduit in. So we've got these wires running right along the street, and the city will be doing all this work, doing all this stuff, and there's no coordination to put conduit in, so that you can come back later, and you could move the wires underground.

Because I fundamentally believe that last mile eventually needs to go underground. We can fight it for as long as we want to, but eventually the cities are going to force us there. And the more you invest in your overhead system, you're investing in something that eventually needs to come down, at least in that last mile. I'm not talking about the entire system. Coordinated identification and action is critical essential service, leveraging city resilient facilities for grid service. Of course, coordinated tree planting and trimming, most utilities do this. Coordinated communication and education, I think most utilities do that.

But what I meant by that slide is, it's really becoming a partner long term. So leveraging rate riders, I've talked about rate Rider LGC. What about a new development? And this is the power that you as the commission have. And Hudson Yard is my best example in New York City. Here's Hudson Yard. Massive new development. First thing Con Ed tells Hudson Yard is, we can only come to the property line. The commission's not going to allow us, because of the cost, to go there. Hudson Yard goes, "Geez, if we have to build electric distribution, we'll build chilled water, hot water, a central plant, a

huge sustainable system. It's going to be cool and credible." Con Ed sees that and goes, "Holy cow, they went to the commission and said, 'Give us approval to go to all the buildings in Hudson Yard.' The commissioners said, 'OK.'" They came back and said, "We'll build all the distribution to your buildings." Hudson Yard said, "Well, if we're not going to be doing that electric distribution, forget all that thermal distribution. We'll just go back to the old way we used to do it, and just deliver power to the buildings."

And so new development, if you stop at the property line, you allow sustainability to happen with that, within that customer. New development is to me where you have an opportunity to either let the utility play, and this is what I'm going to say next, is let them into reliability two-way power flow, I think that, this was the smart grid rider for Commonwealth Edison. They had a rider to basically go do this throughout their system. They didn't get very far, because there just wasn't enough money. Utilities need a master controller to control this two-way power flow. It sends signals to the price assets, to send price signals to the assets and call on them when they need it. But district energy.

So my feeling is, we've got to go one or two ways for sustainability. Either you stop the utility at the property line, or you let them in to district energy. Let them do the chilled water and hot water on the building site. And maybe somebody else does the boilers and central chillers, but if we want sustainable energy systems, we've got to decide. Because in my city, Elmhurst, we're going the other way. If you can believe this, we're building brand new apartment buildings, and we're in Chicago now, and we're putting unitary heat pumps in those apartment buildings.

Now you talk about environmentally not friendly in Chicago, think about from December all the way through March. You're basically running on

electric heat. You cannot humidify in that situation. It's just a disaster. And your costs, I was in one of these buildings for a year while we were transitioning from our home to a condo, and my first bill in January was \$250. It was just totally unsustainable.

So we've got to figure out how, and that's why PEER was designed to work with LEED, is that LEED's doing a great job of trying to get this efficient building and how it looks, but it's not considering the impact of the energy delivered to the building, chilled water, hot water, power. So there's a huge opportunity working together to get there. And of course, maybe a rider on resiliency. But these can all be riders that can be built into your systems working with your city and your utility. So in terms of tools, Rider LGC, look at the ComEd real-time rate. It's one of the best rates we've seen, as well as their demand. Just their standard rate for commercial. You can go to the UHEBC PEER program and learn more about that. And then if you email me, I'll send you, we have an example, utilities' city-scale smart grid plan.

And then the other thing I did, and this is, in one Excel spreadsheet, I took ComEd, and I took all their spending, this has got their entire budget, the rate. It shows their O&M cost, everything, over the last six years, and then I projected out 15 years. If you applied all those riders that I just showed you, including an O&M-shared savings rider, including a few other riders, and I explain all the riders in there, I showed how they could actually lower cost and increase their profits. They could lower the rates and increase their profits. It is possible. You don't think it's possible, but it is. But it required a full set of riders that we designed that could be applied together working, and then the utility working with the city, off they go. So with that, I'll stop right there. Thank you very much.

Moderator: Clarifying questions for Speaker 3?

Question: This is a really fascinating presentation. There were several mentions in both presentations about resiliency. And I'm curious, and clearly in your presentation, there's a sense of the distribution LMPs, the wholesale market prices actually penetrating down to the customers. And I'm curious the extent to which you feel like the technology would allow the ISO to view in an aggregate sense some of these customer demand response capabilities as kind of a dispatchable resource in the long term, and how far we are from getting there, or if that's even possible. And whether that kind of thing, you know, what role that has in sort of the concerns about resiliency.

Speaker 3: I think it's very possible because we're responding to the capacity ISO signals, so when it's a capacity day, you know, the facility will be going to zero power to the grid, at least for those hours, maybe for five or six hours, just trying to make sure they hit the capacity. As long as we have telemetry, we're already getting the real-time price signals. We're getting the capacity calls from whoever our support organization is, whoever supports you in that venture. So it's all there. The telemetry's there. We can get the information out.

Questioner: But the ISO just sees that as kind of missing load. It's not sort of integrated in—

Speaker 3: That's correct.

Questioner: —as a—

Speaker 3: Right now.

Questioner: Like a demand resource that they have, actually have to be dispatching.

Speaker 3: That's correct. But like in the ComEd territory, Monday through Friday, from 9 a.m. to 6 p.m., they'll be at zero. And so now you have

a facility that has islanding capability. It can make a return on that investment. And again, once that investment's paid off, you can change the rates, and you can still use that asset in the future.

Moderator: Next question.

Question: This is a great presentation. On one of your slides you had Westchester County, and you were talking about microgrids, my favorite subject of gas moratoriums. It's my understanding that there was a large microgrid that was planned for Westchester County. I don't know if it's the project you're involved in or were involved in. But because of the gas moratorium, they had to withdraw the fuel cell. They could not do the microgrid.

Speaker 3: That's correct. We were looking at microgrids in New York, but New York is off the table for anybody looking at distributed energy.

Questioner: The second piece that, and I actually learned this in Massachusetts, and it's worth looking at. The City of Boston created, again having the oldest infrastructure probably in the country, a system that if you go to file anything, to put a shovel in the ground, whether it's water, sewer, steam, gas, electric, cable, it has to go through what's called, and I can't remember what the acronym means, but a COBUCS system.

So they developed a software platform that required all of the utilities in that area, if we're going to open up this piece of the street, you're all coming to the party. And don't come back for five, at least five years to do anything. So it's a pretty interesting thing.

Speaker 3: That's fantastic.

Questioner: And I mean, I think the challenge that the department saw, because the legislature had us do a report, was the smaller cities and

towns don't have the, probably in some cases, the intellectual capacity to create a platform like that. But if they do do it, it protects their most valuable assets, their roads and streets, so that they're not dug up every 15 minutes for something. So it's kind of interesting, but Boston does have a pretty amazing system. I know I'm biased, because I live there, but it's good.

Speaker 3: No, Boston's kind of very forward thinking. I think this utility corridor concept, and I think the utilities, the electric usually could be the leader, working with their gas utility partners. And sometimes they own both anyway. So they could be the ones that really help drive the utility corridor concept more fully throughout all the cities. It's a great, great, yeah.

Moderator: Speaker 3, I had a clarifying question. The example you gave about, I believe you said it was an inner-city project, where the utility was doing part of it, and you had a private op. I'm trying to figure the dynamics of who decided who was going to do what? Why was some of it private? Why was some of it utility? What the incentives were for the different players, and why they divided it that way?

Speaker 3: That's a really good question. That's because the developer was being fairly aggressive. He wanted to build a microgrid on the entire property. And he was trying to get through the laws in that state. You had to own all the buildings. But he was going to sell off half of the buildings on the site over time, as the development was built out.

So it became a negotiation actually to say he would move back to basically the buildings he's going to own long term, and just put the microgrid there. And since he had already done the design, and he was going to have solar on all those other buildings, they just worked to have an integrated design that would allow for islanding of the whole facility.

Moderator: Any other clarifying questions? OK, now we turn to the lawyer on the panel. [LAUGHTER] Speaker 4?

Speaker 4.

I'll try not to be too overly legal. Maybe just a little bit. The Moderator asked me to share some views on competition in 21st-century electricity services. And I'll just say that my contribution comes with a little bit of a California bias. We're kind of crazy out West, as you heard yesterday, probably. And we're crazy in all new kinds of ways these days.

I think thinking about competition and the potential competition between utility and non-utility providers of energy services should begin with the consideration of the potentially addressable market, because why compete if there's not growth potential? Is this like a pizza where we're trying to fight over who gets what slice? Or can we grow the market? The traditional applications for electricity services see flat to negative growth. That makes it a very challenging situation to invest into. But I think there is a lot of new growth potential that we're seeing, particularly in California. We're seeing the beginnings of a movement toward mandatory building electrification. So taking the natural gas out of buildings. In the last six weeks or so, eleven municipalities have banned new natural gas connections. There's obviously a lot of controversy around that. It's not going to work in all climate regimes, or many climate regimes, even. But in California, it can work.

There are a lot of questions about what happens to the natural gas distribution system as this process plays out. And to be fair, or frank, a lot of the cities and counties that are banning new natural gas connections are the reason California has a housing crisis. Right? So when Menlo Park banned natural gas connections in new buildings, Menlo Park doesn't build any housing. So they

built like three affordable housing units in the last decade. So we'll see how much this movement in California catches on, and the degree to which it moves into the areas of California that are buildings lots of new housing product. But it appears to be something that is taking on a momentum. And that creates new load growth for electric utilities. This creates opportunity, both on the utility side and on the customer side of the meter as we think about deploying new products in residential and commercial construction.

In addition, there's obviously a lot of new growth in load potential for transportation. California has identified a target of five million EVs by 2030. Opinions vary as to whether we will achieve that target, but that is the goal, and a very large fraction of the EV fleet in the US is in California. And when you go to places like where I live, it does appear that EVs are beginning to take over a substantial market share, and that creates both opportunities and challenges in the distribution system, both on the customer side of the meter and in the system as capacity demands change as a result of the new load.

I think the other potential new growth opportunities have already been well-covered, but you know, this question of what we can do in terms of price responsive demand, and California's actually a kind of a laggard in that place and in that area, but there's certain a lot of opportunity to deploy technology behind the meter, to generate new growth. And I would just emphasize that these are areas where there's potentially enough opportunity to create benefits for utilities and non-utility players. And the question will be how to maximize the gains for all parties, and avoid a sort of zero sum outcome.

I should just say, also, that, at this point, given what we know now, in states that are interested in deep decarbonization, building electrification and

transportation are the way forward. Right? Getting the fuel out of distributed applications to the degree that we have, we are using fossil fuels, is the way forward. And that raises all kinds of questions about cost and choice and meeting customer needs, but this is the direction that at least many states are taking in their policy development process.

So the big question then becomes, who will provide the services? And I think there are reasons to think that IOUs have a lot of advantages when it comes to providing these distributed energy services. And there are reason to think that they don't. And I'll just run through a few of them. An enormous benefit to having IOU provision of services is roll out at scale once approved by the commission. It's much more straightforward, given regulatory approval and ability to place cost and rates, to see roll out at scale. IOUs also benefit from a very low risk and so low cost of capital, so we can do this more cheaply.

On the other hand, IOUs are not necessarily the most nimble players. They have poor incentives to innovate when innovation might impair investments that they've already made, as we heard about earlier. And I think there are also inherent conflicts of interest in the sense that if IOUs are allowed to rate base investments that generate load, they are potentially incentivized to spend customer money to get customers to spend more money. And this is a big part of the reason that we don't see GE and Con Ed and ComEd as a single entity, as they used to be in the early part of the 20th century, and we see them as standalone companies, one that provides products to consumers and one that sells energy to consumers.

As we think about moving to a more active, engaged customer side of the meter, this question becomes relevant again. How to manage those

conflicts of interest. Unregulated provision of energy services I think has a number of advantages. It can be more nimble, and we see that in the California ecosystem in spades. Customer differentiation is a focus of the unregulated companies, and I think regulated firms still struggle because of their focus on system optimization and reliability to think from a customer perspective, and from a customer differentiation perspective.

That's where most startups begin. They try to identify a narrow subset of customers that have a pain point that they can solve. And that is not typically a utility frame of focus. It can be, but it's atypical. In addition, it's easier to fail as an unregulated provider of energy services. And I think, until we have a better sense for how and what energy services are actually desirable on the customer side of the meter, both from a private perspective and a system perspective, ability to fail is a real advantage. We want to see entry, but we also want to see exit. We want to see things die. And it can be hard to kill utility programs.

In addition, the incentives are much higher for success. The successful unregulated entity is going to be able to keep the supernormal returns from their successful innovation, utilities less likely to be able to do so, if at all. Cost of service versus value provided. On the other hand, unregulated providers obviously suffer from scaling problems, barriers to entry that raise prices significantly. And I'll talk about one of those in more detail in a moment. And because of the greater risk, higher capital cost. I think the risks are real, and so, I tend to favor pricing them accurately, and therefore an unregulated provision of these services.

What are the traditional and the nontraditional competition concerns that arise as we think about provision of energy services on the customer side of the meter? So I'm going to break this into two

groups, sort of the old, what I would characterize as the old antitrust thinking and the new antitrust thinking. Traditional antitrust concerns involve consumer harm, attempts to monopolize an area. I think utilities already have a monopoly, and we'll talk about that in a second. Exercise of monopoly power, and most importantly in this space, probably tying.

So utilities are state-chartered monopolies. As such, they are in general exempt from the federal antitrust laws because of state action immunity doctrine, also called Parker immunity. And in an incidental way, Noerr-Pennington, which is sort of a First Amendment exception to antitrust law. There have certainly been cases where state action immunity did not protect investor-owned utilities. Cantor is kind of the famous old chestnut involving light bulbs and Detroit Edison, where a light-bulb program by the utility was found to be an impermissible attempt to monopolize the light bulb market and anticompetitive as a result.

More recently there was a dispute between Arizona Public Service and Solar City that was settled, but not before the Ninth Circuit found that the case could proceed on an antitrust claim. So there is some question, and the case concerned proposals around rate structure and the allegation on the part of Solar City that the proposed rate structures were anticompetitive and an attempt to push the company out of the market. As I said, there was a settlement, so we'll never know exactly how the courts would have ruled on that question, but I think it raises the issue of how commission-regulated authority is going to work in a distributed energy context, where you have customer-sited generation that's not utility-owned, that has the potential to compete with utility-owned generation. But where that competition is modulated through rate structure.

I would add, and I think this is actually probably more significant, and I should just say, on the antitrust side, there's an important judicial reluctance to enforce antitrust law. If you strictly interpret it, if you interpreted the antitrust statutes on their face, you might see attempts to monopolize everywhere. That's called companies making money and growing.

And so there's an understandable and legitimate reluctance to use the tools of the Sherman Act and the Clayton Act too much. There's been a lot of ferment over the last five years about, or in sort of new ways to think about antitrust law. And in particular with respect to the tech platform companies, what I'll call FANG. This new antitrust thinking is very much focused on the use of a platform to suppress innovation. So Apple's App Store being used in ways to suppress new entrants to the app market that would compete potentially against Apple-provided services. This new antitrust thinking is much more firm-focused, focused on the competitive environment in which firms operate, less focused on consumer harm. It is largely untested in courts, but I think politically it's extremely important, and in the regulatory sphere it could become important.

And I would suggest here that the utility space needs to pay close attention to what's happening in the tech space because we're going to get pushed by whatever happens there. New approaches to regulating platform competition in the tech space have enormous implications for how platforms like a distribution-system ISO might operate, interacting with customer-sided generation, customer-sided refrigerators that are, or more likely, water heaters that are interacting with the distribution system and taking commands.

I should just say before moving on, I just want to emphasize here, the new antitrust thinking, and the influence it has on the electricity space and

innovation in the electricity space is not likely to come through some sort of blockbuster litigation. This is not going to be the AT&T breakup. It's going to come through influence on the way that policymakers think, the way that regulators think, and the influence of that thinking on competition policy as implemented at the PUCs.

So what would a pro-consumer competition policy look like? I think we need to start from fundamentals. We need to optimize the use of the shared monopoly services. So the IOU system needs to be optimized. We need to provide, it would provide clear signals to optimize the use of customer-owned DER. It needs to limit the cream-skimming. Cream-skimming is a term I use. I don't know how common it is. But the idea of many of the criticisms for net energy metering, that it's harvesting customers and basically harvesting, avoiding cross-subsidization and pushing costs onto non-participating customers.

That set of provisions is possible in exchange for greater monitoring of anticompetitive conduct by the incumbent monopolies, especially in terms of rate design. And lower barriers to entry for innovative services. And I think right now, there are important legal barriers, there are important regulatory barriers, there are important engineering barriers that are maintained in terms of interconnection rules. And I think the most important one is actually the last one, that there are important controls on information that's central to new entrants entering and competing in the market for customers, and I'm going to talk in more detail about that.

A key barrier that we observe in California and I think in other states that are especially interested in distributed energy resources, is information. Information is a trade secret in the utility industry. It's essential if you want to differentiate customers, however. It's critical for making the value proposition to potential customers. But

AMI, advanced meter infrastructure data collected by IOUs is, I think, in practice, used by IOUs as a moat to maintain their monopoly relationship with the customer. That's a totally understandable position. The customer relationship is the most important monopoly that a utility probably has. That was something that was said to me in direct response to a question about this issue by a prominent utility CEO from the Southeast. He said something to the effect of, it would be pried from his cold, dead fingers.

Why is it so important? I think the reason that information is so important is this customer differentiation and value proposition question. New companies grow and survive by solving customers' problems. Not all customers have the same problems. And the more that research examines AMI data from customers, and I'll talk about the access issues in a second on that front, but the research that's been done at Stanford, at other places, looking at differentiation of AMI tends to indicate that residential customers in particular do not look anything like the residential average load curve. When we decomposed, or colleagues of mine decomposed the AMI data from PG&E service territory, we found that using Hagen value decomposition, there were something like 200 Hagen values. The biggest concentration of variants was only 6%.

So there's not a single residential customer. And that means opportunity for different services, if those customers can be identified. If they can't, you're dealing with a situation like California had during net energy metering's heyday where my wife didn't like to go to Home Depot because wandering the aisles at Home Depot were low, minimum-wage hires from Solar City that would accost anyone who had the temerity to want to like buy a light bulb or some mulch, and try to get you to sign up. And that was the customer acquisition approach. Random, scattershot. That's not how value is created by most startups.

And information is the barrier. Of course, privacy matters more than ever. And I think here, again, the FANG experience matters the most. The key question for electricity, and it has been for the better part of a decade is, what is the balance between appropriate, open access and customer privacy? Nobody wants people to know the details of the goings on within their home, particularly not in Arizona. And that's a legitimate concern.

However, customers also like innovation and services. And where information is a barrier to that, we need to strike a balance. So the question, the way I like to think about this is, do we want to be like Google in the energy space? Google probably wants us to be that way. Or do we want to structure more like HIPPA, where information is closely protected. There are strong legal penalties for disclosure of information. And where is our AMI data on the spectrum right now? I'm just going to talk briefly about some personal experiences that we've had at Stanford, and I think many researchers have had relating to the acquisition of AMI to provide a little perspective about where we are in terms of universal release.

So if you want to get AMI data to do research, you generally have to sign a contract for a single year of data. The contract is an extremely burdensome negotiation. There's new terms added for each contract year. So you never just get a renewal. So you get your 2018 data, and then sign a similar contract for 2019 data. You basically start from scratch for every year. At least the utilities we work with typically impose personal liability on the researcher for any release of the data. So if Vrinda Gopal, a colleague of mine, somehow the PG&E data leaks from his lab, PG&E can come and take his house.

This is a reality that I think most researchers don't talk about, but I think it's very important to think about. There's a lot of self-censorship in the research that goes on in this data. There's a concern that if researchers publish things that are perceived as harmful to the IOU's interest that gave them the data, that they will be cut off from future access to AMI data. And that leads to self-censorship in the academic work. There are apocryphal tales about such kind of cutoffs occurring because certain researchers published papers that were not viewed as favorable to the entities that had provided them with the data.

And this is the situation where the researchers are not in competition with investor-owned utilities. At Stanford they might start a company, but most academic energy research is not focused on startup generation. For business purposes, increasingly, there are relatively straightforward opt-in policies for information from advanced metering infrastructure. Customers can share, can give explicit permission for individuals firms to share data. The data has relatively low latency. And the data quality is good, although certainly some firms would argue it's not good enough, and that's by design. But the key issue here is that it requires customer acquisition prior to data access. So you're not solving my wife's problem at Home Depot. Solar City can get her data once she signs on the dotted line.

But not until then. And that means very high customer acquisition costs for companies that might have a solution for particular customers but not for all customers. They're picking needles out of a haystack. So what would a modest shift look like in this? I think there is a potential to have pro-innovation, pro-competition information rules that are a modest step toward the FANG world from HIPPA, where we basically are today in the electricity space. That proposal would keep the current rules for opt-in, for low latency data. Nobody wants to know,

nobody wants random companies to know when they're on vacation using their smart meter data. But it might allow open access to high latency data with available consumer opt-out.

So what that means is, you couldn't have this week's smart meter data for my house, but you could have last year's data. And if I didn't want you to have it, there would be a place for me to opt-out of that data sharing. That would allow the kind of customer identification that's so crucial to reducing costs for early startup ventures, and for experimentation. And I think it would go a long way toward allowing greater competition and innovation in the space.

I think there are enormous opportunities for investor-owned utilities and unregulated firms in electrification. I think the size of the pie can grow substantially, and in fact, the only way the pie is going to grow is if electrification happens. Creating and capturing the value requires collaboration, however. Investor-owned firms are going to be good at some things and really bad at others. And, just to elaborate on this a little bit, the point that was made earlier about local governments is enormously important here. Community choice aggregators in California are kind of a poster child for lots of bad things. Ask the Public Utility Commission about resource adequacy and you'll get an earful. Where they are really good is in thinking about the interaction between land use, building codes and electricity. The CCA for the Peninsula wrote the electrification code that is becoming the law all over the Peninsula as local governments enact new building codes to be consistent with the new version of California's energy efficiency code.

So there's this very interesting interaction between the retail electricity provider and the local government, because the local government is the retail electricity provider. And they can do things much more effectively than an investor-

owned utility ever could. I think the first area to address in improving the competition situation on, in the distribution system, is this question of information. The firms that I interact with that stand the best chance of creating value for customers face an enormous barrier in terms of identifying which customers. They know they're out there. They can look at our research, which anonymizes all the customer data, and see the customer that they could serve. But they can't find that customer without a randomized search, picking up grains of sand and hoping that they find the one that's the diamond.

And if we want to move in a direction where we electrify transportation, and we electrify buildings more rapidly, which will create load growth for utilities, I think this is an important hurdle that we need to remove from firms that really aren't trying to compete to provide bulk electricity or serve electricity over wires. So thank you very much.

Moderator: Are there any clarifying questions? Thank you, Speaker 4. Any clarifying questions? OK, if not, let's reconvene, I'm sorry, did I miss somebody? Oh, so let's reconvene at five 'til.

General discussion.

Moderator: OK, if everyone takes their seats, we can get started. So I don't see any placards up, so I will start the questions. And the first question is, did I miss, OK, I'm sorry. Someone is the back has a question. No?

Comment: I can wait.

Moderator: No, no, go ahead. That's fine.

Question 1: OK, well, so first let me thank the panelists for all their input. I am actually very involved in the distribution, resource kind of

integration in ERCOT. So I've got mainly a few observations to make, and it's more piling on than disagreeing with anything that was said. But on that front, for us one of the main kind of concerns ends up being lack of visibility in terms of what's going on, in the distribution system. And it isn't so much that we have to know that. It's more about monetizing the full value of these resources they want to participate in, ancillary services and other features from us.

But we have kind of run headlong into the distribution utility, and they're not used to sharing information with us and things like that. So that ends up being a big barrier that I think needs to be overcome. The other thing that I've run across, and it kind of touches on the IOU not wanting to share information, but it's a slightly different nuance. The utilities are used to polling at a rhythm that doesn't align with market-based needs to poll the AMI meter data. And you see this on the retail level, but also on distribution level, resource level. And I don't have a great answer for this, but because it's kind of sunk investments that have limited ability to poll. The other thing that's unique to ERCOT that we're struggling with, with these resources is, resources are paid on a locational marginal price, a derivative of that, but load is paid on a load zone price, and that mismatch creates all kinds of kind of difficult challenges. We've been focused on trying to get LMP payment for both, but I don't know how that applies in other jurisdictions, but that's been a really big deal for us.

So I just wanted to make those observations, because I think those are add-ons to some of the very good points that were brought up earlier. But the other thing I would just share as far ERCOT goes is, that's where we see a lot of resources coming into the market, and it's not the kind of traditional large utility-scale projects as much as some of these distribution-level projects. So I just wanted to make those observations and share with the group.

Moderator: Comments?

Respondent 1: I would just say that with regard to how we're reading our meters, my utility is fully AMI-deployed. And, for those customers who are on a demand rate, we're reading those meters every 15 minutes, and then we're averaging it over the hour to determine their demand rate. But as we think to the future, how do we get information quicker, how do we bring it back to our system, quickly analyze it and get information back to the customers so that they can make changes in their home?

One of the biggest criticisms in our service territory about the three-part demand rate is that the feedback on how they performed it too late for them to do anything to change. And so it's thinking about how do we get interval data at a shorter interval that does align with the market to the extent that it can, so we can get to that future that I was talking about earlier in response to a question I received, so that we can kind of bring the two together, the market and what our end-use customers are actually using, to signal to the customer what is the right thing to do, and how can they make changes to control what their ultimate energy costs are going to be in their home?

Questioner: So I think, again, that's a really good point. I do think there's a slightly different kind of mindset to look at this, also, though, because especially in ERCOT where you're starting to see a lot of different retail type offerings, so retailers will want to poll their customers to understand how much demand response they have, for example, on things that they can curtail. And what they're finding is, you only poll three times a day, even though the meter's function is reading every 15 minutes or whatever, and those are huge barriers to these new kinds of products that people are thinking about offering.

Respondent 1: I completely agree with that comment, especially with regard to demand response. We don't know when an event or an emergency is happening until we're already in it. We don't plan for that. We don't know, or say, oh, that gas unit's going to trip off, or that coal unit's going to trip off, and now I need to figure out, you just have to respond.

One of my T&D guys asked me to build him a real-time DR program. So I certainly don't have a solution. I've only been digging in for about two months now. But coming from the real-time operations and having responsibility for the real-time operations, real-time trading desk, I think I bring a different perspective. I understand what he's trying to solve for. And I hope we get to that place where we can, in meaningful way, have a real-time demand response, because you're right, polling three times a day isn't going to be sufficient.

Respondent 2: I just want to say one thing briefly in response, which is that I think the issue of how to optimize the data to make it useful to multiple parties is a really complicated one, and it's not one that is necessarily aligned with the other incentives that the wires companies face. And I would just note that there are places in the world where what restructuring meant was generators subject to, in a competitive marketplace, a wires-only monopoly, and a meter owner that's separate from the wires, who sells data to multiple parties, multiple retail providers. And that kind of a structure might be better aligned with the kinds of data needs that you're expressing.

Moderator: Next?

Question 2: I'm also thankful for this panel, and I want to take sort of the flip side of the question we just got, and ask about the pricing side of the story. So obviously if you were, if you want meter information to go to SCOs that are going to change the operation of the system or something,

that's a problem, and you've got to do all the polling and everything that we're talking about. But the other way is prices to devices. And so you send the price signals out there, and the devices respond to the price signals, and that's the way I tend to think about the problem.

And I would categorize the papers and the studies and the initiatives that I've read on this, which is not comprehensive, but I've read a fair number of them. And the largest group of these papers and studies is completely silent on this question. They just don't address it. So if you look at the Reforming the Energy Vision in New York, and all the kinds of things they're talking about early on. There was one paper that dealt with this, but it was basically ignored, and all the other kind of conversation. So they're sort of assuming that we're going to do this. This gets into a problem of how you deal with aggregators and all the other kinds of things that come up with that. The second class of papers, I read one yesterday that was just published, and it makes the assertion, which is, "Well, it's easy. We know what the wholesale price is at the connecting bus, and then we have to scale it up for losses on the distribution system, and that's all we need to know, and now we're ready to go. OK?" And I read that, and I said, "This can't be right. That doesn't sound to me like a description of the system."

And I hear the third category, which is the things we're talking about today, where you're down at the distribution system where we worry about voltage levels and voltage control problems. And now we're going to have two-way flow and self-healing things. We're reconfiguring the network all the time. And which strikes me as right. That's the technology problem, and so forth. But that has very powerful implications about whether or not we can actually calculate and communicate the prices that send the right signals so that people are doing the right things down there. And I know how to do it in theory. I know

how to do it in the classroom. But the problem that I've been worried about, and other people I know who are working on it are worried about it, [UNINTELLIGIBLE] particularly at Boston University, is we do not know how to do this at scale. We can do it for a small toy example, but when you're trying to do it, the RTOs are calculating thousands of locations every five minutes. That's teeny tiny compared to the problem of what you have to do down at the distribution system, where we're talking about millions and millions of locations.

And then, we just don't have the communication capability to process the information. What are we going to do here? I mean, this seems to me this whole distributed energy efficiency thing is missing the problem that we actually don't know how to do it in a way that makes things better. We do know how to do it in a way that makes things worse, which is sending the wrong signals and then set up people to compete to make money against the wrong signals. We spent yesterday afternoon talking about that problem. So we're really good at that. But how can we do it in such a way to make it better? Then we have to get the right pricing models. And I don't think we actually know how to do it. So what are we going to do here?

Respondent 1: I'll just start by saying, I don't know. We're working very hard, because it's not just the pricing signal that we're trying to solve. The other issue that I'm working on internally with the teams that I get to work with is, how do we treat it like a real resource also so that we account for it in our integrated resource plan? How do we value all of these customer-sided assets and resources and oil it up into a true integrated DSM as an input to our integrated resource planning? We are engaging with a whole lot of folks in energy efficiency space, who show up also in California, and things that start there, they want to see in our state also. And we need to figure out how to calculate all that. It is

completely different than how the utility has traditionally approached any of this. Right? And so I don't have an answer for you, but we're working really hard on it.

Respondent 2: Prototyping, I think, is critical. And when the Moderator and I worked on the Galvin Electricity Initiative, Bob Galvin, who ran Motorola, was just really big on prototypes, at city scale, not at, like you said, lab scale. And I think what we're seeing in the prototypes we're building is three levels of control: primary, secondary and tertiary. At the primary level, the engine, the battery, the UPS, the flywheel, will respond immediately, milliseconds to change perturbations in what's happening in the local distribution system.

A system we were running at a facility, our neighboring facility came over to us and said, "Wow, you guys, we're so glad you're there. Our voltage all summer long has been all over the place. It's affecting our motors, other equipment in our, and now it's rock solid." And that's because our generator was sitting there on that circuit holding the voltage rock steady for all the customers on that circuit, even though the utility itself, without that generation source, was having all kinds of problems on that circuit. So that primary level. Then secondary, it's like a master controller, which is processing the tertiary controllers, which are optimizing and looking at things. And I think it's time-framed. You go from milliseconds or cycles to milliseconds to then seconds or minutes in that tertiary control, or five minutes or ten minutes, whatever it is at the tertiary level. I think there's a lot of work going on right now on the control side to be able to have automatic response so you're stabilizing everything, and then optimizing over here on the other side, the control side. I don't know if that helped at all.

Respondent 3: I think it helped. I heard divide and conquer. You submeter and subcontrol

systems and allow them to make some autonomous decisions, and then that passed up to a much larger system. But a lot of times I think it's the communication protocols are what we have lacking. I think legacy systems for manufacturers, where they dominate a certain space, become a challenge coming.

But an interesting topic that I thought you brought up was, your generator from one customer was helping another customer, but that other customer wasn't paid for that service, because there's no rate structure to support that. And so I think that the rate structure is integrated with your question, because we don't know how to control the systems properly, because we don't know how we're going to be rewarded for the control that we might do. I think that's one of the challenges we have to overcome, is the rate structure needs to be understood so that as I build the control, and I build this divide-and-conquer system, I understand how I'm going to control these systems, and what level of control I need in order to get the most value from whatever rate structure may eventually evolve.

Question 3: Hi, thank you to the panelists. I just want to make a comment and then ask a question. I think one of the questions was, "Would utilities entering this space stifle innovation?" Yes. So there's your answer. And it's not just startups. I mean, we're talking about Fortune 100 companies globally that have heavily invested in the capabilities, hundreds of millions of dollars, to do distributed energy resources and efficiency, and they come to a state fully invested, with no request for rate-payer recovery. All risk is on shareholder and the executives.

So I don't really understand why a state, except for what they're used to or what they're familiar with, wouldn't opt for more innovation from not the utility. Just because of the different business models. The question I have, there seems to be a striking parallel between this discussion and

something from roughly 20 years ago, which created the Open Access Transmission Tariff. Striking parallel about utility-owned or not utility-owned, access to systems, being able to sell unfettered. And I think I heard someone mention a DSO or a distribution ISO, and the potential for an OADT. Now, granted FERC is one place to go to cover the entire, well, most of the country. So that's convenient for an OATT. This would have to be state by state, clearly, and that's complicated. But could you all comment on the need for an OADT and a DSO for this space to really grow and show its potential?

Moderator: No comments on that? I think we actually did, a year ago we did a panel on what you could do in nanotechnology, but go ahead.

Respondent 1: I would just say, I think that's a very hard problem when you don't know necessarily the system attributes you want to price. And when you're dealing with a significant fraction of participants in a distribution system that are not sophisticated players. And those are two challenges, and what's happened in New York seems to be a move with the market first, and I would sort of contrast what California's doing, which is subsidize the heck out of a bunch of things and put them out in the world and see what's valuable and what's not. I don't know which approach is the right one, but more information about where there are value creation opportunities seems important as a precursor to market design.

Respondent 2: I'll just comment that I think it's a great idea. And I don't know if there's a place you could pilot it, because I think the New York rev process would have come out completely different had they formed something like an OADT to take that concept forward, because it was just, to me, the REV process was taken over by the utilities, and just taken off in a direction that was just completely counterproductive to

what they were trying to accomplish in New York.

Question 4: Could I just follow up? Do you all have thoughts on just some of the basic system needs that are not out there? So advanced meters to collect that data, protocols to share one's authorized data. And I don't just mean consumption data, distribution-system-level data. What are the inverters saying? I could find a customer that's optimal for a behind-the-meter, distributed-energy resource, but on the other side of town, it might be optimal for the system. If I can find out both bits of information, I can go find a customer where it helps the system the most.

So we have a problem with no collection devices, no sharing protocols, and that seems to also proceed the need for design, because how do you even define value before you've identified the need or the customer? So could you comment on that?

Moderator: Actually, part of this may relate to the point that Speaker 4 was making about what data ought to be available, and what not? I mean, the first question is, who does customer data belong to? But then beyond that, you raise questions about system data, it's never been clear to me why that shouldn't be public information. And on flows on the system and where the constraints are in the distribution system. There's no privacy implications to that.

So one of the things that would be interesting is to develop protocols that reflect what data, simply there is no privacy. There may be some security issues, and I think we talked about that in that panel we did on security, but there's no privacy issues. Then there are other issues where there are privacy, but as Speaker 4 pointed out, some of them are historical, I think you called them low latency, and some of them are ongoing, like, am I out of town right now, that kind of stuff. And try to make some distinctions and protocols. I'm not

clear that anybody's ever really tried to systematically go through that. There's been no discussion about it.

But it would be useful to really figure out exactly what it is. And certainly for people that are selling distributed resources, whether it's demand response or distributed generation, the system data would be useful without even getting into the privacy data. Any other comments on that?

Respondent 1: Well, you say there's no privacy information on the system data, and I'm not sure that those users that want that privacy would agree. From my industry we have companies selling services where they'll take the aggregate sample data through a metered consumption, and they'll do a data analytics on that, and they'll subdivide the load into what they believe is consuming that power, when it turns on, when it turns off.

And so I think if I'm this hypothetical research laboratory, and I'm investigating certain areas, I would be afraid that someone would start to parse the data going into my facility to determine what I'm doing. I can't imagine an example of how that works. I was a skeptic when those that came out with the building software that would predict what has happened in the building, but I have a device on my home right now that samples the data and tries to predict what I'm using in my house. And it tells me every morning when my son goes to work at six a.m. that the garage door opened, because it has figured out what the garage door signature looks like. So I can imagine that privacy could be an issue at some point in that data.

Questioner: So what system data actually shows?

Respondent 1: I think it depends on what system data you're talking about. Are talking about flows on the system? I think that could show, yes. Again, it comes down to the amount of sampling

that you get of that data. If you're talking about an aggregate over a year, probably not. But if you're talking about the five-minute samples, ten-minute samples, or even smaller samples, which may be what you really need to understand the opportunities in the grid as we see it, then yeah, I think you could.

Moderator: Other comments?

Question 5: Thank you. Well, before I come across as a cranky old bastard, let me just point out that in 1980 I started working in solar energy, and if you had told me in 1980 that we'd have too much solar in California in the middle of the day, I'd say you were crazy.

Moderator: That establishes that you're old, not that you're cranky.

Questioner: Yeah, I get that. [LAUGHTER] Now for the cranky part. So I represent utility-scale solar and wind and all. We've been able to see over the last ten years sort of utility-scale photovoltaics go from 50 to 60¢ a kilowatt hour, down to two or three cents. And if you want to put storage on that, there's some deals that have been done for three to five cents. So solar has obviously proven itself to be a low-cost technology to deliver electricity. However, in California, we now have a situation where, now that we've learned to do this for two to three cents, let's go spend 20¢ a kilowatt hour to put it up on the roof and come up with something very different. And in some applications, I don't have a problem with that. But the vast majority of it I think, there is some concerns.

So there's basically two issues here. One is, I live in the SMUD service territory. It's a very progressive utility. It has a well-balanced renewable portfolio. They've been on the cutting edge of a lot of things in the energy sector for a long time. They have a NEM problem. For every dollar they spend on low income customers in a

subsidy, there's three dollars' worth of subsidy going to my neighbor across the street for his rooftop solar. OK? I'm a non-participant. I don't care if my neighbor wants solar on their roof. Cool. They can do whatever they want. I just don't want to have to pay for it. And my concern is that there's a growing problem in California where we have 6-7,000 megawatts of rooftop solar under NEM, with stupid inverters. They're the old inverters, and they're not smart inverters, so they're very limited in what they can do. Totally invisible to the ISO. And we are having to spend a lot of money upgrading things just to basically keep ahead of things.

So, one, is that I think there's an equity problem here from the standpoint of, we will take care of low-income customers, which we should do, and the people who are most capable of actually paying for electricity bills, homeowners with some financial wherewithal, are completely off the system. So who does that leave? And I think this is a growing problem that we're going to see in California, because you're going to have a bunch of people in the middle, middle-income people, basically, footing the bill. And that's going to be, I think, politically ultimately a problem.

So that's issue one. You know, how do we insure that people basically pay their own way? As I said, if people want to do microgrids and everything else, great. And if it has a value to them, they should do it. And they should do it out of their own pocket, and that's wonderful.

The second one, and Speaker 4, you may have some thoughts on this, is really the legal issue. And I think NEM, when it was first put together, and we may have moved beyond NEM, so I'll qualify that. But you know, the early FERC law on this, and I think it's still the case, is that they're billing arrangements. So it's not a sale for resale of electricity. That's how they get around it. It's just basically, you're trading kilowatt hours with

your utility, and FERC's not interested in that at all. I think that changes pretty significantly as you start putting large microgrids together, and basically selling power to the ISOs and whatever. And the question really is, we have a system, PERPA was based on avoiding cost, and we may be moving into a different paradigm. Is the law catching up with this? Or where are we there?

Respondent 1: Well, I would say to your first point that we need to evolve a rate structure as the context evolves, right? And it might lateral, I would say that NEM, on a straight energy rate, is probably not an appropriate rate structure in California, although we've moved to mandatory time of use, the time-of-use intervals are changing to reflect the solar peak, I think starting in December, at least in PG&E service territory.

And so there's a gradual evolution away from where we started, which I think is appropriate for lots of different reasons. As to the legal issues around DSO and sort of distribution-system transaction, transacted energy, I think there are legitimate legal questions there. They especially will arise if and when distribution-system investments have to be made to support aggregation that's transacted into a wholesale market. FERC is treading carefully there in rule 841, and I think there's a 841a as well. But until we see the case, I don't think it's possible to predict exactly how that comes out. Beyond saying that I think it's an important issue, and it's an important issue to focus on the jurisdictional question as the situation evolves.

Moderator: Questions, comments?

Question 6: I want to touch back on the question that's sort of relating what's happening on the customer-distribution level with the broader, larger wholesale market. And I guess ultimately where my question is coming around to is, what is really the role of FERC in sort of setting policy

or market design changes that are happening at the customer meter level?

And on one level, you would think on a state-federal standpoint, they shouldn't be there. However, when one of the big arguments for capacity markets is they're needed because if you don't have sufficient installed reserves, you could have a generation deficiency where you never meet peak load, and the lights go out during a super peak.

The counterargument to that is, well, if prices simply go up enough such that customers voluntarily get off the grid, which is something that this kind of development would provide, you would never have supply and demand out of balance. You would never have a resiliency or an installed reserve deficiency, because the market would fix it. So my question is, and one of the examples that I have on this is, Baltimore Gas and Electric has about 8% of their super peak load is at the LDC level responding to prices, and they're paid I think \$1,200 a megawatt hour in the day-ahead market when they trigger you to respond, and you get about 500 or 600 megawatts and BG&E responding are high. PJM has scarcity pricing mechanisms, but this is outside of that.

So what you see as the load goes up, customers are being paid \$1,200. The load stops going up, but prices stay at \$50, even though it's 105 degrees in Baltimore and humid and there's all these actions being taken. So my question really goes to, are there design change, market design changes or FERC policies that need to be promoted to ensure that what's happening at the customer demand side, particularly with respect to responding to prices during scarcity events make their way into the wholesale market?

Moderator: Who wants it?

Respondent 1: Well, I think, to my mind, the big question is the opt-out provision. To what degree

is it permissible for FERC to require some sort of ability for demand to participate in wholesale markets? Or can they allow state-by-state opt-outs? And, again, we'll have to see, I would not offer a prediction beyond saying that I think in the long run a more efficient market will allow for demand-side participation. That's from a policy perspective probably optimal. But we also live in the real world where states value their prerogatives and their ability to control what's going on in their jurisdiction. And so how we evolve for that world, how quickly we evolve in that direction is the real question. I know that's not satisfying.

Questioner: I guess I'm curious amore about not necessarily so much where the legal is, but where should it go? Because I think you could articulate an argument for the states that, hey, you might not need to pay for capacity market prices if you are actually using these distribution resources to meet demand, to ensure reliability during super peaks, and by having customer actually respond. Your consumers are benefiting ultimately with the more efficient market.

Moderator: I think of it as a policy matter, that I agree with you. I think the political problem, which is what it is, is not just guarding their prerogatives, but it's also what would be required of states to participate in that kind of program. One is, they'd have to move towards dynamic pricing in a much more serious way than most states have chosen to do. And secondly, the customer is obviously going to opt-in or opt-out. So that's another variable.

But essentially, for FERC to offer that, saying, if you opt-in, you can do this. I mean, I don't see a problem with that, but I just see a lot of states resisting moving to the kind of retail pricing regime that, and it goes back to the thing I've always talked about, which is, we spend a zillion dollars figuring out how to have the perfect wholesale price signals, and then spend the same

amount of time and effort and money trying to make sure no customer receives the price. So what you're offering is sort of an enticement to avoid that kind of mutually-exclusive arrangements. But getting the states to move in that direction is not going to be easy. Not just because they're guarding state prerogatives, but just because the politics of moving in that direction are very difficult, even though substantively, I think your point is well taken.

Question 7: Just to that point, both PJM, I don't know about New York, but both PJM and ISO New England are reducing their forecasted load and capacity procurement based on behind-the-meter-resources. So we're already starting to see that happen, regardless of the jurisdictional issues. And you can shut me down.

This may be an inappropriate question, because I know we're here to talk about markets, but I guess my biggest concern with all of this still remains the reliability issue. And knowing what resources are there, and how much we can move off of a centralized grid to distributed resources. And if this is not off topic, I would love to hear some responses. And if it is off topic, I apologize. You don't have to answer.

Moderator: First off, no one's capable of shutting you down. [LAUGHTER]

Respondent 1: I was just going to say, I don't think it's off topic, because that's one of the central arguments we're having internally when we're trying to quantify what is this actual resource, and how do I boil that into my IRP, like I was talking about earlier? Because at the end of the day, reliability is what the IRP group is working on. They are planning to make sure that we are there at every moment of every one of our customers. And so since we've only completed one full DR season right now, they're just not comfortable. They're not there. We need to do more testing. We need to do different locational

tests. We need to try all the different sorts of things so that we can get people comfortable.

Now, coming from the customer technology side of things, I want to do that faster. I want them to just trust me. It's going to be perfect. Don't worry. But that's not how it works. So reliability at the end of the day is a core tenet in who we are as a utility. So that's always going to be a part of the decision making process. So not off topic from my perspective.

Moderator: Anybody else?

Question 8: Just a reflection, and then, well, let me start with a comment. Speaker 1, you had used the expression that if all power is green, why do we even need efficiency? I think that is a question that needs to be asked, because there actually seems to be a split in the environmental movement, in Maine at least, between one side will say the only green kilowatt hour is the kilowatt hour not consumed, which is quite astounding. That came from a federal senator.

And on the other side there's companies looking at the kilowatt hours that are negatively priced in ISO New England, and try to find uses for them. For example, in charging batteries might help, I don't want to get into proprietary details, but they've got ideas and ambitions on using it. So I think it's an interesting question to pose, and it needs to be posed more often, because if you're getting productive services out of that kilowatt hour, I'm all in favor of it seen being used, rather than just turned off, shut off.

The other comment is, and this is just trying to think more broadly about the impact on the utilities themselves, TNDs or restructured or unrestructured, the old vertically-integrated types, and we're talking about open access distribution tariffs. If any of you are familiar with the telecom industry, this was what led to colocation. It was a fundamental change in the

way that the telephone companies that operated for nearly 100 years. And it had consequences when there was subsidized access creating it on economic bypass, and it had beneficial consequences when there was economic bypass, when it simply, the phone company itself was delivering services or not delivering services that were needed, or delivering them very inefficiently and overpriced. So I think if we cross the threshold, we're doing exactly what went on in the telecom industry, and we should draw some lessons from that.

Moderator: Any comments? Lessons?

Respondent 1: I would just second what was said on the panel about this conflict between efficiency and clean. That's definitely playing out in California, and clean is winning. And that makes the older generation of energy regulators in California extremely uncomfortable.

But even the consultants that provide information to those people sometimes are uncomfortable with their results, because they pretty clearly show that as the California grid is evolving in a very clean direction, especially if you count large hydro and nuclear while we have it, efficiency at the individual building scale isn't the right way to think about the problem, except in terms of cost. And there are still significant benefits to efficiency, but they're very different and it's a very different justification than the traditional one.

Respondent 2: So I agree with that. That's what I see happening as well, is that, is efficiency perception-wise is not viewed positively when you compare it to green power. Renewable power is the thing people want. It's what people ask for.

The example I gave of the California homes is a classic case. You know, buyers will pay more for a home with solar panels on it than one that has

more insulation, because obviously they can't see the insulation. They can't point to it. They can't brag to their relatives that they have that. I don't think that my relatives out in California are going to call me and say, "Hey, I just bought a home with R30 wall insulation. It's really slick." [LAUGHTER] You know, but they'd call and say, "I've got some really neat solar panels, and I can do the following with them. I've got a battery that does all these wonderful things." And, like I said, you know what engineers talk about with their family. Right? [LAUGHTER]

Respondent 3: But you can tell them that the wall insulation's better for privacy purposes.

Respondent 2: There you go. Better for privacy purposes. But efficiency's not sexy. It's not the thing that sells. It's the old thing in the industry. I believe that what you'll see efficiency have to conform to is the smart building concept, where the smart building is really what we're after. What we do want is, we do want buildings that operate properly. Unlike where I'm sitting up here right now where we're all freezing, we don't really want to be really cold. We want to be just right. We want to have a little bit more control over our environment, from lighting to HVAC to the air supply.

We see more and more standards coming in, for example with schools, where they want to control how much carbon dioxide is in the atmosphere, so that the students will be brighter and smarter, because that will make all of our kids president someday. And those are the things that we're after. It's that smart building concept. So I think efficiency will have to mold itself to fit a different paradigm in the future. Again, as I mentioned, I think efficiency and that smart building will also play a role in some of these grid services that we talk about as well.

Moderator: Yes?

Question 9: I don't have a mike, but just a quick question. There was some reference to [SOUND OFF THEN ON]

Respondent 1: I think having a more independent oversight of the process, I think it got started in an independent way, but then it lost its, what I—

Questioner: I do see one of—

Respondent 1: I'm sorry, lost its independence in terms of all participating by all the stakeholders in that process.

Questioner: Well, I mean, specifically what would be the problem? Because I thought it was designed to be very open.

Respondent 1: I just don't think it came out that way. I think it was attempted, but it just, you had, a new utility group formed that sort of took control of the REV process. Hiring the executive director, and really had, to me, over-influence on what it was, because I think the commission was headed in a good direction. I just think it got taken off in a different way.

And I think some of the outcomes, and having some kind of open access distribution approach would have better served it. But I'd also like to make a comment about the electrification and the efficiency versus renewable. To me that seems like a debate about rebates and incentives, and not necessarily markets, because I think efficiency has come to a point where it is, it's just going. It doesn't need, necessarily, the rebates anymore, and it's rolling. And so I think there is this community that's fighting over incentives, versus there's a whole marketplace out there that's acting. And I brought the example up of building electrification.

That's not the efficiency way to go. And we're still 30 years away from 100% renewable. If not further away. And so it seems it's strange that we

get pulled by just what happened in New York REV, we get pulled by groups in directions that just take us completely off-track of what our real objective is, which is a more efficient, sustainable system.

And so that example I gave of building a new residential building in my town that's basically all-electric, and it's extremely inefficient. And yet we're supposed to be in this super high-efficiency time, and I've got unitaries, you know, you have heat pumps that don't really work in Chicago, efficiently. Down in the South, you know, that would work much more effectively, and I'm just looking going, "How the heck could a building like that get built today?" Now, it feeds the narrative of electrification to renewable, but now that building will be there for 30 years in Illinois, where we're not going to be even close to that in 30 years, just the way we're going. So it just seems like we get off track a little bit.

Respondent 2: I always had a question about the REV program that I have never fully understood. My understanding's always been that there's not an interest in investment in measurement, you know, instrumentation of the network. And yet there was going to be a market design process. And I think that I have always wondered how that could work, without a significant investment. I guess it's occurring in New York now, but you know, the REV program really began before there was an instrumented distribution system, what I would take to be the technical requirements for actually having enough information to operate and run a market. And that system is really expensive. So if there's not a political commitment to pay for it, I have questions about how effective a market design can be.

Moderator: Yes.

Question 10: This question is really directed to Speaker 2. You said you wanted to get down to real-time pricing, and I agree with you

completely. I think it's a very serious problem, and I just want to ask you, but I don't know the experience in Arizona, but I've done the calculations, in the past, for PJM, because the data was available. And this is time-of-use pricing.

Let's take time-of-use pricing as a generic idea, which is being pushed, you know, something we should be doing more of, and we could do better, and we could run all these systems and have these controls based on these time-of-use stories. And we've been talking about this for a long time. And this is really hard to do and get through the administrative process. And then you do the calculation, and you say, just looking at the wholesale prices, not getting into the complexity of what's happening on the distribution system, how much, if you had a perfectly designed time of use rate, which we can't get, but if you had a perfectly designed time-of-use rate, with 24 hours of time-of-use rate, and no revenue imbalance, everything was working perfectly, how much of the variants in the price that you wanted to signal to people to use would you capture in that process? And that's the proper measure of the welfare effects of this.

And the answer for PJM is approximately 28%. So you'd capture approximately 28% of what you're trying to capture by going from flat rates to time-of-use rates. I think spending a couple of decades trying to capture 28% is probably a waste of time, and that we should just fight the battle and go all the way down to real time, because otherwise, when all these other devices are out there, people are going to be doing things which are actually counterproductive, because we're not sending them the right signals. Same issue I had before. Does that jive with your experience in Arizona about the scale of these numbers? And how urgent it is that we actually get something that respects the real-time prices?

Respondent 1: I think that's an excellent point. I don't have a number to share with you. I'm sure we have that someplace. And I'm going to go back and track it down. But I think we have to get closer to the real time than we are today. I don't know how feasible real time is, simply because of the latency between how frequently we read the data, how long it takes to get back to us, and then how long it would take us to actually send feedback to the customer. I don't have a good sense of what that complete cycle would look like. And I don't know how achievable it is, because I imagine just the volume of data that we're going to be creating in that world. Right?

We already have tons and tons of data. But we're not using it today. And to me, that's a huge gap that it's sitting right there in front of us. Why are we not using it to make more intelligent decisions? Why are we not using that to inform our customers so that they're better educated, and they're making better decisions, because in the absent of that, all we're doing is, we're putting out these time variant rates, which work better in our service territory than the flat rate for all sorts of reasons.

If you've been to Arizona, and if you've been to Arizona in the summertime, it's pretty hot. So we want to shift as much load out of that on peak period as we can. Our summer load is more than double our winter load, and so that's a significant challenge for us to overcome every day. And so, how do we get more real time? I don't know that where we're at today is the right answer, but I don't know how we're going to get there in a meaningful way. Or what is meaningful. I guess the question is, what would be meaningful to the customer? Is it real time, real, real time? Or is it 15 minutes? Is it five minutes? Is one hour enough for them? I think we have to do a lot more work in this space than where we're at today.

Respondent 2: Can I respond to that question with a thought? You know, one thing that strikes me about the challenge of getting toward real-time pricing, I was surprised by your number. I thought it would be lower for the effective, capturing the time-of-use variants in the real time price and time of use.

One thing that strikes me is the potential that electric vehicles have for increasing consumer acceptance of real-time prices. We have two EVs in my households. We have a Tesla and a Volvo. The Volvo is completely dumb with respect to rates, and the Tesla has programmable charging that just tells it to turn on or turn off depending on what the rate is. It strikes me that if there were more car, and the Tesla is connected to cellular networks at all times.

It strikes me that that is an opportunity for introducing real-time prices to retail customers that's pretty unique, because you're deploying systems, pieces of technology where you have controllable load, where you have the potential to fully charge a vehicle and not impact customer intuitions about how much charge they need, at least under most circumstances. You can always override it, right, and just pay the price. But there might be potential there that doesn't exist in many applications.

I would argue that the key barrier to real-time prices is public perception. So if you could put a consumer product in lots of people's hands that involves exposure to a real-time price and increase comfort with that idea, you could change a lot of things in the rate conversation at the utility commission level.

Moderator: Last question.

Question 11: Thanks, everybody. So I've been listening here intently, and I wanted to pick up on some comments. You know, energy efficiency and demand response is a really big part of what's

happening in the country right now, and it's being driven through all these programs that are being run, whether by the utilities, aggregators actually participate a lot, and in ERCOT they're a big part of it.

And I just wonder if, even if we get the price signals out there, when you look at the economics behind the energy-efficiency calculations, they look very far out into the future. They're sort of really facilitating making decisions for consumers going forward. Do we think if we get them the better pricing, are we going to get enough response from them? The way that I think about this is, much or many of the energy efficiency measures that are being implemented have a shelf life, seven years comes to mind, I think, with how long they last.

So even though they get accounted for in the demand forecast at the ISOs, which is really becoming important, they expire. And then I kind of wonder if in some timeframe we've got better pricing to folks, would we then be bridging the gap? And would the actions get taken? Or are we envisioning that we'll have devices that actually just take the actions for us? And it's just kind of curious what you think about that, those prospects. Thank you.

Respondent 1: I would say, I don't know the scale at which we would see any kind of behavioral change. But what I do know is that with our modernized rates, with the demand, the three-part, and the time-of-use rates, we're already seeing a significant change heading into the on-peak period. And so I can't help but wonder how much more change I would see if I was able to get information to customers in a more timely manner.

In my role in customer technology, the very first question I have to ask myself on any project is, what's the customer experience going to be with this product or service? What's the customer

journey going to look like? And how do I make it as best and as meaningful as I can make it? And one of the challenges that we get with the demand and time-of-use rates, well, mostly with the demand, is they've already blown it out, and now they can't do anything about it. They set their demand. They probably set their demand for the month, and now they're upset. And customer satisfaction is a huge part of our decision-making process. It has to be. And so, I don't know how much more change we might see, but we have to be better than we are today.

Moderator: Any other questions, comments?

Respondent 3: So just a final point on yours, your question, is I think you'll see, you talked about devices making decisions for you. I think you're going to see more of the devices making decisions for you. I think that, when you talk about residential, there may be some cases where residential will change their normal mode of operation, and whether they'll keep that is unclear. But I think you're going to see devices having to make a lot of these decisions and receiving the price signals if we can get the communications worked out.

Moderator: Last question.

Question 12: Thank you. So I had one quick question to maybe put to the panel. I thought it was very intriguing how Speaker 3 has particularly said this, but perhaps the initiative was already kind of moving away from the utility into the private sector, or at least the impetus for controlling this or managing it.

But I thought perhaps there's a reason for that. Maybe incentives aren't quite right, especially in a regulated environment. And if I were a utility executive, I would want to have the appearance of doing all these great things. But in reality, I want to make sure I have plenty of opportunity to invest in the distribution system. And so

inefficiency's actually a really good thing. Right? Inefficiency means the denominator can get much larger, because you need more resources to manage the same number of people.

And is this an issue? I mean, we haven't talked about it yet. But is this potentially an issue where in some sense utility executives are probably thinking still, "Wait a minute, how could I make sure I still have a good opportunity for investment here and growing the base?"

Respondent 1: So from the utility perspective, I would say, with regard to how do we make our investment decisions, a reasonable level of certainty that we're going to get recovery is part of the decision-making process. So I think Speaker 4's slide with the pros and cons laid it out very well. Those things that we've already received approval for, they're very scalable. We'll blow it up, and we'll do it well.

When there's something new that's coming along that we want to do, and the process to get it approved from our corporation commission locally, it's a long, protracted process, then the decision is, do we want to wait for recovery? Or, are we confident enough that we will put shareholder money at risk? And that's not an easy decision to make. That's a decision that you have to take to approximately 14 different executive committees to try to get people comfortable with. And then you'll do it all over again just to make sure.

But in the example of our Take Charge AZ pilot, our electrification pilot that I was speaking about during my presentation, that's just such an instance where our executive team is so passionate that this is the right thing for us to do that we are putting shareholder dollars at risk. But that's one pilot. That's one project. And there's so much happening in the world, and so many things that our customers want, and so many things that we want to do, that we are kind

of cycled or held back a little bit because we need to know we're going to get some level of recovery.

Moderator: Which goes to the question that we discussed a little bit, but not a lot, which is, should this activity be regulated at all? Or should utilities that want to do it set the spinoff subsidiaries to do it in an unregulated environment? But on that tease—

Respondent 1: I apologize. I just want to add one more thing. Or do you just create a sandbox? Can your commission create a, here's a bucket of money that you're going to go and get innovative and develop new solutions that work for your customers and for your systems. And then operate within that bubble?

Moderator: Sure. Just don't call me from Jamaica. [LAUGHTER] OK, so I want to thank, join me and thank the panelists for an excellent job. [APPLAUSE] And we'll be sending out notice about the next meeting. Thank you.