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Rapporteur's Summary*

Tuesday, March 26, 2019

Session One.
Competition in Transmission: Policy Direction and Experience Since Order 1000

In Order 1000, the FERC opened the door to building high voltage transmission on a competitive basis and turning away from the traditional right of first refusal. What, if any, changes have occurred in the transmission market as a consequence of this decision? What has been the effect on the costs and pricing of transmission? What impact, if any, has there been in regard to congestion and locational prices? Have we seen innovations in technology and/or rate design as a result? What impact, if any, has there been on enabling greater access to non-transmission assets to enter the market to compete for providing services that have historically been provided by transmission facilities? How, if at all, has reliability and/or dispatch operations been affected? Is there a need to develop a hybrid model of expansion where some circumstances require a first refusal approach while others lend themselves better to open competition? Based on experience, what are the best policy options going further?

Moderator.
Good morning everyone. Just a few opening remarks. Hopefully everybody got a chance to read the summary for this session this morning on FERC Order 1000. So, what are some of the key questions? What have been the effects on the cost of transmission, what has been the effect on reliability, and what are the best policy options going forward, including the current status quo as an option? Speaking about my company – and notice I'm speaking about my company and not for my company – we are one of the largest electric utilities in the country. We own over 40,000 miles of transmission line; enough to go around the globe one-and-a-half times. We operate in 15 states and we currently operate in four transmission entities including PJM, SPP, ERCOT, and MISO. We have historically been investing about three billion dollars a year in capital in our transmission. We are also active in the competitive market with over two billion dollars spent to date. So, I do believe we can provide a significant perspective here. We do embrace the changes that FERC Order 1000 presented since its issuance. Our experience has taught us much, I think, to date. One thing that we'll probably get into more today is that we tend to favor the sponsorship model - the best idea wins - over the cost-based model. We'll probably be talking about that more. We do support competition at a level that makes sense. We don't want competition just for its own sake, so we have to carefully weigh the benefits of competition--where we can provide the best value for customers against the real costs, and competition has some real costs, in terms of

administrative costs, perhaps inhibiting us, the utilities, from at times collaborating as much as we once did, and other unintended consequences. So, with that, I'll look forward to hearing the thoughts of our panelists today and sharing more of our perspectives along the way in the ensuing discussion that will come this morning I'm sure.

Speaker 1.
Good morning everyone. So, I'm kicking us off with an analysis that my colleagues and I have been putting together of the potential cost savings offered by competitive transmission. So I'm going to begin by giving you some background on where we – what the scope of the analysis is and what is the historical trajectory of transmission investments in the US and the current state of competition to kind of set the stage for talking and discussing with all of you today about the benefits and costs of competition in the transmission space.

We recognize there are many view points on this, particularly – and I think, to the moderator, you introduced it very well – depending on where you sit and what the current situation is for different utilities. We recognize there are many view points on this topic, and it turns out to be a relatively complex regulatory question, and I think it's extremely well-suited for this venue to discuss the tension and the give-and-take and, of course, the state versus federal jurisdiction issues and lots of tension about policy implications. And then we leave you with some conclusions and recommendations.

So, first of all, the focus of the analysis is really looking at the amount of investment in transmission over the last decade and the ongoing investment going forward and recognizing that competition, while introduced by Order 1000, has been limited in practice. We wanted to understand whether competition is bringing benefits to customers and, if so, how much and in what ways? So that's sort of the background and the context and the focus of the analysis.

So, what's the scope of the examination? We are focusing largely on regulated transmission, so, while it's interesting to discuss the competitive space in merchant transmission, we're really talking about regulated transmission; it's a public good, it has regulated cost recovery, and, typically, it's in the realm of established and, I'll say, nonincumbent transmission providers. So, the competition piece that we're talking about today largely falls into the Order 1000 space of regulated transmission asset investments subject to competition.

So, what's the experience so far with competition in transmission? There are many jurisdictions that certainly have complied with Order 1000. Different ISOs and RTOs have different frameworks and approaches, but, largely speaking, there is a process for inviting sponsors or developers to compete for certain projects in transmission. We include data from ERCOT. A lot of this discussion is in ISO/RTOs and ERCOT, and then we actually have some discussion about non-RTO/ISO regions. Outside of the US, Alberta and Ontario both have significant experience in competitive processes for transmission, and Brazil as well has auctioned off certain projects, and in the UK they have considered tenders for off-shore grid projects. And the reason these are important, while we don't yet put any of these in slides, are that those processes have already articulated that they've brought significant cost savings to customers, so I think it's relevant to consider international experience.

Here's a picture of the investment in transmission over the last couple of decades. As you can see, it's grown from about two billion a year in the late 1990s to about 20 billion dollars a year in transmission investments in the most recent five-six years. This is in the US and FERC jurisdiction so, you know, we're missing a few pieces of it, but, largely, it's steadied out in the last few years at 20 billion dollars a year. And, therefore, because we're spending quite a bit on investments in transmission, this matters. Right?

How much savings we can garner from using competition in this space really matters.

Just reflecting this slide here in a tabular form, essentially, it's over 10% per year growth in the ISO/RTO regions in the last five to eight years. It's slightly less for regions outside of RTO/ISOs – about 6% in WECC outside of California ISO and, in the Southeast, another about 10%. So, this just gives you a sense of the growth over the last close to a decade.

We started this analysis to understand potential cost savings from competition. We started gathering information from all of the ISO/RTOs – that's the first natural place to gather information – and we found that it's actually quite difficult to really gather relevant and enough data to understand how much investment is actually being made in transmission. We can gather data about investments already made, and we can gather information about transmission projects planned through the ISO/RTO, and it turns out there is a gap between the two, and the amount of the gap…we expected some sort of mismatch in the data because of timing, because of sources, because of treatment of revenue requirements and things like that, but we didn't expect the gap to be that large. And it turns out that there is actually a significant gap between what is being tracked and planned through the ISO/RTOs versus how much investment is actually made, and, across the ISOs and RTOs, about 47% are not actually tracked through an ISO/RTO planning process that has a full stakeholder process where the data is transparent. So, it actually makes the data process very difficult. And so, the number one thing - I will sort of steal the thunder a bit – is that transparency is lacking in this space. So, we don't actually have a good way of tracking the planning process, what projects have gone through, what are the costs, what are the initial cost estimates, what the costs actually turned out to be – not very well and not very clearly, and certainly not the entire universe of projects. So, again, we expected some gap, but we didn't expect the gap to be about half. So, half of the transmission projects in the United States that are in the ISO/RTO regions are actually not going through the full stakeholder process through the ISOs.

There are essentially two types of competition. In PJM and New York, it's a sponsorship model, where the ISO/RTO identifies a need and invites different sponsors to come forward with their proposed solutions to the need. Various different developers come forward with very different solutions at different costs. So, we observe that different innovations come through, different solutions, different technologies, but also different routing, and certainly even different financing. On the bid-based side, it's much more specific, where the ISO/RTO identifies the need, perhaps there's an open window to invite solutions, but then, ultimately, the ISO/RTO identifies the specific project, with specifications, and developers come forward and compete on more or less costs and experience and other O&M costs and things like that. So, the sponsorship model is broader, and what we call the bid-based model is much more specific to a particular project. And PJM and New York are the ones that are using the sponsorship model, whereas CAISO is much more on the bid-based approach.

Over the last, I'd say, five years, there's sort of been this eager waiting for projects to come through the competitor process and people trying to understand, you know, when do you get another window of opportunity where you're competing for projects? So, we endeavored to find out how much of the overall transmission is actually going through the competitive space. So, between 2013 and 2018 – and actually we included the other MISO project that materialized in 2018 – about 2% of the transmission investments across the United States actually have gone through a full competitive process. So, overall, it's been about 1.6 billion dollars out of 90 billion dollars over the five years or so and it's been about 2% of that projects. So, that also surprised us. I mean, I guess we knew it was small, but we didn't know how small it was.

This amount is relatively significant; that's about 300-something million dollars out of 20 billion dollar a year of investments in transmission. Here is a full list of all of the projects that went through a full competitive process, where a full set of developers come forward and propose different solutions and proposed bids. There are 16 projects in the US and three projects in Canada. So, we asked a question about, well, why is that? Why is the sphere or the universe of projects to be so small, and what is actually setting the criteria? And it turns out each ISO and RTO is doing it slightly differently. We also see a reaction from Order 1000. Even though every region has complied with Order 1000 with their filing, there's really a limit to how many projects – as you can see, 2% - how many projects actually come through the competitive process. And then we asked the question, well, how are these ISOs actually articulating the criteria for projects that are subject to competition? And the two rows where you see all the checkmarks, indicating projects that are excluded from the competitive process – they're actually, per Order 1000, projects that are locally cost allocated. That means that if the project cost is allocated to the utility's own rate payers – usually it's one utility's rate payer – those projects are not subject to competition, and, if it's an upgrade to an existing facility, it's usually not subject to competition. So, per Order 1000, I guess, FERC has decided that those are okay to not be subject to competition. And then, aside from that, there are other exclusions – sometimes *de facto*, sometimes specified – but, basically, as you can see, in ISO New England, MISO, PJM, and SPP, based on the need date, reliability projects are also not subject to competition. And part of that issue, particularly in New England - and I've seen this happen - is that, basically, you can't get any project through unless it's a reliability project, but then, if it's a reliability project that's needed within three years, they're not subject to competition. So, there is sort of this issue of setting criteria and also sort of getting around the criteria so that most of the projects are not subject to competition. And at the bottom here there's an exclusion based on voltage.

Now, one thing that's unique about New York and CAISO – is that their exclusions are less stringent than the other regions. And I guess what we take away from this is, if certain regions can be more inclusive, then there are not compelling reasons why other regions need to be more restrictive. So, if we were to revisit this thing again, the question is, can we open up more projects to competition? And that's what this table is intended to show.

Next, we look at, well, okay, if we're trying to understand the potential cost savings associated with competition, then we need to first understand what we are comparing it to, understanding fully that every single transmission project is unique; it faces unique challenges, particularly on siting, routing, and therefore uncertainties about the costs. We recognize that it's very challenging to compare everything on an apples-to-apples basis, to compare them relative to each other, but we attempt to do this anyway.

So we took a look at the various different projects for which we can get our hands on the costs associated with those projects, including cost escalation between initial estimates and final project costs. And, on average, (I know average kind of averages away quite a bit) the cost escalation is about 34% across the sample of these projects, which span five ISOs and RTOs. And you can see that even across the ISO/RTOs, depending on the different projects involved, there's quite a span between something like 18% in SPP to 70% in New England. So this shows that, historically – again, this is just over approximately five years – either the cost estimates are too low or there are reasons, and potentially very justifiable reasons, for cost escalations, but we do observe significant cost escalations from the initial estimate. Again, recognizing there are cost uncertainties, there are justifiable reasons for escalations, but this is what the data shows – that there are significant cost escalations.

So that's just conventional, traditional transmission projects. Utilities develop them, there's a cost estimate in the beginning, then the project goes through siting and various different challenging stuff, and then it ends up with significant cost escalations. Then we ask the question about competitive projects. For the 15 projects that have been solicited through the competitive process and the selected winner of those bids, what are they coming in with in terms of their cost estimates for the projects or the proposed cost for those projects? And we observe that it's about 40% below the initial estimate either provided by the ISO/RTO or the lowest cost from an incumbent utility meeting the same need. Okay? Again, this is surprising, actually, and it may be skewed by a few projects here and there, but this is the limited amount of data we have. In addition to that, in the last four or five years, many of the projects that have come through the competitive process and are selected come with a cost control or cost containment clause. Now, we understand that the cost containment contract is not perfect, and it can't be perfect because there are still uncertainties associated with these projects, and we also recognize that competitive projects are not complete yet, so it's difficult to compare apples to apples, but I think what we recognize is that, even if these competitive projects end up with significant cost escalations, they have quite a bit of head room before they reach the kind of cost escalations that we observe in the traditionally developed projects.

So here's an attempt to quantify some of this. So, if we put the bids relative to their estimated cost, and we say, if you had a head room and you also experience 41% or so cost escalations, what would that look like? And even with that, we observe about 15-30% cost savings; even if the competitively selected projects have some cost escalation, purely because they have included some cost containment and reduced cost estimates going into the competitive process.

Here's a table that shows you our estimate of the cost savings by ISO and by the project, and you'll see the range is across the board. What's interesting about this is that in Canada, the UK, and Brazil, they are also coming in with about 20-30% as the cost savings associated with competition. Okay? This is not perfect science, but we do estimate that the cost savings could be in the range of 20-30%.

So, I want to just dive in and say, if we had approximately 100 billion dollars of spending on transmission in the next five years, and if the current share of competitive projects is only 2%, what would happen if we increased that space to something like a third of the transmission investment? We estimate the potential cost savings, just over the next five years of capital spending, to be between six to nine billion dollars. So, I think that's a provocative number, and I'm very interested in your reaction and feedback.

Just in summary, here's a graph that shows how much of the transmission in the US is actually not subject to ISO/RTO full stakeholder processes, and then the gray on the side shows about the 2% that are subject to competition, and then, again, there's a repeat of the previous slide that basically says, if we increased the 2% subject to competition today to something like 33%, and we assume a savings of 25%, that amounts to six to nine or on average eight billion dollars over the next five years.

So, just very quickly to close this out, we do think that improving tracking and improving transparency on the costs would be very important for this industry, and I think there's a lot of room for improvement there, and, two, we recommend increasing and expanding the scope of competition. That's what I have prepared. Thank you.

Clarifying Question 1: You had a slide up there, I have to find it, that says something to the effect that only 2% of projects are subject to full competitive processes and then, at least for PJM, you showed two projects that went to nonincumbents.

Speaker 1: Correct.

Questioner: But are you defining full competitive process and an award to nonincumbents as the same? Because I would argue they are not the same. You can have a full competitive process and then end up giving it to the incumbent – it doesn't mean it wasn't a competitive process. So I'm trying to understand if you've melded those two?

Speaker 1: We went back and looked at that, and that's why, in this graph, you see that PJM has, like, two slivers of gray, and we recognize that there are other open windows where there was additional competition and it added to that gray bar. And I think, overall, it doesn't increase the 2% to more than 3% if we included those.

Questioner: My point, though, is, if we have an Order 1000 competitive process and the incumbent wins, I would argue that's a full competitive process, but you seem to be saying that's not a full competitive process, because the incumbent won. And I'm just trying to understand your terminology.

Speaker 1: I think we define full competition as if the incumbent actually competed for it - not that they won but they actually competed for it.

Questioner: Alright. Then I think the numbers are larger than that, but we can differ.

Speaker 1: It's not just an open window for incumbents to propose their own projects, so we do define full competition as some competition –

Questioner: If I can just clarify. Open window means anybody can submit a proposal?

Speaker 1: Correct.

Questioner: So, to me, that's a competitive process. You seem to be saying that's not a competitive process?

Speaker 1: It's not as full as we'd like it to be, but we went back and to look at that more fully, we did add the projects that are subject to all the open windows and I think –

Questioner: I think your numbers need some correction, but okay. Thank you.

Clarifying Question 2: I was wondering if you had any sense of the kind of statistical confidence level you have in this analysis you've done? I do note you said – I couldn't really see the slides from where I was sitting very well – but you indicated there was, I think, a 34% increase in a sample you took of some utility projects, which I think you said was small. And then you mentioned there was a 40% increase, I think, in some savings that you also indicated may have been skewed. Then you made an assumption that for a third of projects, costs could be reduced by 25%, I think. I just wondered what kind of statistical confidence level you felt that this analysis yields?

Speaker 1: That's a very good question. I did preface my remarks by saying that it's very difficult to find the data, and we spent a lot of effort to making sure that we had the proper data. I think every ISO would actually acknowledge that there has been cost escalation associated with transmission projects in the past, and I think probably all the regulators recognize that as well. So, of the projects that we can gather information for for the 2013-2017 period, this is the data that we find. Again, I recognize averaging takes some of it away, because there are some projects that meet the target initial estimate, but some of them surpass the initial cost estimate by 100%. And the report will actually have a table of all the information that's associated with this graph, but, on average, these are the numbers that we see.

There are projects where, you know, the ISO did not have an initial cost estimate because it's a sponsorship model, so we have to have something to kind of prepare as a reference. We're not biasing the results; we're just saying we need some kind of reference to compare it to.

Questioner: Is it fair to say that you're not that confident, from a statistical standpoint, but this was the best data you could find?

Speaker 1: We are confident of the data that we gathered, and, of the competitive projects, this is the entire universe of the competitive projects, and so we –

Questioner: Do you think it would be helpful if more data were compiled over time?

Speaker 1: I completely agree.

Clarifying Question 3: So, half of the transmission dollars that are invested occur not through ISO/RTO processes? I'm just trying to understand. That half, is that distribution investments, is it local transmission plans? What are the criteria that determine whether transmission investments go through the RTO process versus not?

Speaker 1: My understanding is that when a utility plans its local reliability projects – and this is not distribution, it's transmission level – many of those are either upgrades or replacements. They are not rising up to the ISO/RTOs purview. And similarly for the PJM supplemental projects, they are not going through the entire stakeholder process. So different regions have a different level of monitoring but, for example, in California, my understanding is that the utilities making upgrades on their own systems – many of those projects are not even documented anywhere in a public way, let alone ISO/RTO process.

Clarifying Question 4: Going back to the cost escalation slide – I think you had 70%, If I read that correctly, for ISO New England. I think you said the time period was 2013-2017. Is that the time period for ISO New England?

Speaker 1: Yes, but this includes all the major new projects in New England.

Questioner: So the 70% you have – those are for projects between 2013 and 2017?

Speaker 1: That's right. I actually need to double check whether there's a typo on this graph, because it shows a little bit earlier than that, but that's the intention - to track down all those projects between 2013 and 2017.

Clarifying Question 5: Back during the discussions of Order 1000, there was a lot of discussion that, if we opened up the competition, there might be alternatives to transmission. And I'm just wondering, based on your study, whether you saw alternatives to transmission being introduced, and what sort of cost savings were associated with that?

Speaker 1: We did not focus too much on alternatives, but, based on other experience, I think we're just at the tip of the iceberg on looking at alternatives to transmission. I think each RTO/ISO has a different process, but we did not look at the whole process and see how much the demand response or other alternatives or generation are solving the problem and what those costs are.

Speaker 2.

Thanks for the invitation to be here. I appreciate the opportunity to come back. I think the last time I was here I was talking about seams, and my theme was, "Stuck in the middle." And that's actually a theme that would work pretty well for this topic, too, but I don't like to repeat myself. So I started thinking about, you know, is there a theme that I could pursue? And I think Order 1000 is pretty exciting but, certainly, a lot of people don't, and that led me to think about my 13-year-old daughter, who thinks what I do is really, really boring. Now, in fairness, she thinks pretty much everything is boring, but one thing she does like is Hamilton. And Hamilton, the musical, got her interested in American history and the American Revolution. And so I started thinking, well, hey, maybe there are some analogies here. Right? Maybe the *Federalist Papers* are like the road to Order 1000, maybe our stakeholder process is like the Hamilton-Burr duel. Right? It looks like this is going to be a good theme. So, I'm telling her this this weekend, and she looked at me with a look of horror and said, "Mom, please tell me you're not going to rap?" [LAUGHTER]

I am not going to rap. But the slides are done, so we are going to talk about transmission. All right, so I'm representing an RTO, but I'm representing the MISO perspective, and so there's going to be some things, I think, that I speak to that are maybe different for MISO than they could be for PJM or California, just based on our structure. So, MISO is an RTO. Our focus is the reliable, low-cost delivery of energy, so that fits in very well with thinking about how transmission is an enabler to that. Our states are mostly vertically integrated, with traditional rate regulation. The exception for us is Illinois and a little bit of Michigan. We're very diverse. You can see from the map that we cover a large geographic territory: all or part of 15 states plus Manitoba, which doesn't deal so much with Order 1000 but are in this nonetheless. We have, I don't know, around 200 members across nine sectors: transmission-owning members, companies that are pure load-serving entities, competitive developers, independent power producers, people representing the environmental sector, and the like. Even within our member types, we have a lot of diversity. Our 51 transmission-owning members range from small public power entities to cooperatives to large investor-owned utilities. So we've got a lot of viewpoints, I will say, and opinions to match, as we think about how to go forward and plan transmission. The benefit of having such a large geographic region, though, is that it does provide some reliability and economic value in capturing that diversity, but, again, where the rubber hits the road is, how do you get people on the same page?

We have a history of facilitation of regional transmission investment, and I think that's really helped us deal so far with the transition we've had in the resource mix, so I think this is something everybody has going on, industry-wide. We've seen a big increase in MISO in wind generation, in particular, and then we are looking forward, of course, to even more changes in the resource portfolio mix and also to activity that's going on on the load side. But significant buildout does tend to come in waves, so this isn't something that happens every year. When we did the multi-value projects in 2011, it was 5.5 billion dollars. The last of those projects is actually in front of the state commission even today. So it's a long-term play. There was a lot of great engineering work that was done to make that happen, but, without a doubt, the number one key to success was the ability to get a critical mass of folks on the same page about the need for the transmission and the value of the transmission. And I think that need still holds true today.

When we think about Order 1000 and its goals in terms of increasing the amount of transmission projects, lowering project costs, innovation, the transmission alternatives, and cost allocation, you know, I share former FERC commissioner Tony Clark's opinion that some of these goals seem to have some fundamental tension that might be at odds with each other. So, from a general Order 1000 perspective, and we're talking about competition today, most of that's what MISO was already doing. Right? Regional planning – we had cost allocation and the like, and I think that was all valuable. We put in place a new competitive process. This wasn't a skill set that we had; this was something new that the RTOs had to do, and I think we've developed a solid and effective and fair process. Innovation - we're not seeing much, and we could probably have a whole different discussion on RTO structures and why that makes the consideration of non-transmission alternatives challenging in the first place, but I think it's also fair to say that the biggest driver for non-transmission alternative considerations is technology emergence, and I agree with Speaker 1 that we're really at the front end of that, and we're starting to see it.

So this picture of a battle is the MISO stakeholder process. Mostly, we don't have the swords, but sometimes people bring them. We don't have metal detectors at the door. But, you know, stakeholder consensus is the key to success, and it is a real challenge to get there, and that has always been true.

I could do another whole presentation on challenges for transmission, thinking about regional differences. Right? If you are in Mississippi, you know, maybe the poorest state in the union – you don't want to pay a penny more in your electric rates, no matter how much benefit that's theoretically going to bring you. And if you are in Louisiana, you probably want local solar; you don't necessarily want wind from Iowa. And trying to find a way to kind of bridge that gap and deal with the rising tide raises all boats is a challenge in and of itself.

So, we're early in our experience, because we do have this transmission comes in waves issue - as Speaker 1 mentioned, we've only had a couple of projects so far – but our early indications are that the Order 1000 process does bring some challenges. Probably the most obvious is there's an additional voice in the room. It's one more voice among many, so we bring that in. I think, more subtly, what people don't recognize from an RTO perspective, and particularly in a region where we do have vertically integrated utilities per state regulation, MISO is a little bit in a quasi-regulatory position, in a way we weren't before. So, if you are a state, I think you start to have some concerns about some jurisdictional questions. In MISO, you know, states like the idea of cost containment -- I think everybody likes that idea – and lower cost, but also they don't necessarily like the idea of somebody else making the decision about who may be able to come into their state; they would like to make that decision themselves. Perhaps they want more control over their existing utilities, which they can get, versus a competitor coming in. And so some of these, I'll say, political challenges are really the challenges that we are seeing.

In general, I just see an increased amount of suspicion across all of our sectors of everybody else's motives and, if your objective - which I think it is for Order 1000, including, in theory, the competition part - is to get more of the right transmission built, you have just an inherent hurdle there that's going to take some time to get through.

So, you know, I think this is clear but, you know, it's all about the Benjamins, or the Hamiltons in this case. So we talk a lot – and Speaker 1 talked a lot about – the dollars related to our experience from competition so far. So we have, at MISO, in our two projects, seen some innovations in cost containment, so we have seen that same trend. What we don't talk as much about is that we've got a lot of downward pressure to achieve that in return on equity. Whether that's a good or bad outcome can be up for debate, but it does seem at odds with some of the previous views on transmission. We talk a lot about how many projects are being bid and how many projects aren't being bid and what are those dollars and how do they compare.

I think one of the good things that has come out of competition is that across the board we are seeing more focus on improved transmission cost estimates, but the problem is, even with the data that's available, we're like at apples and kumquats, because we were just in a completely different paradigm a few years ago than we were now. The requirements for what was required for a cost estimate - they were much lower, and so it makes sense that you see difference. And we see, in general, that that's improving, even outside the competition. When we're talking about the dollar amount of projects being bid, it feels a little bit to me like we're rearranging deck chairs on the Titanic, if our real goal is to get more transmission built. When we look at the transmission that's been built in MISO (I'm going to exclude the multi-value projects which were pre-Order 1000) more than 75% of our transmission is upgrades to existing facilities, and that's a number that has not changed since competition. So there's a lot of suspicion that now folks are going for more localized projects, but that's not what our experience is showing us in MISO. And if we go to what's not cost allocated, it's pretty much everything except for those two projects that we have. So the reality is, we just aren't having, right now, the kinds of projects that seem to make sense for competition.

Will we have more? Yes, I think so, if we can get everybody on the same page, but I think there's more time in front of us, and it doesn't seem like a great use of our time to be debating about some of these, particularly these existing facility upgrades.

Probably the elephant in the room that we don't talk about as it relates to money is cost allocation. So, ultimately, this is about who pays. And that is not an easy question – reference my Mississippi to Iowa example earlier - and it's going to take a lot of work to get there. So we can talk all day about competition, but until we get some fundamental agreement on this question of who pays, I just don't see us making a lot of progress, which leads me, really, to my last point, which is the question of where do we go from here?

So, do we ditch it – ditch what we've got, or do we replace it? And I'm honestly not sure I care. [LAUGHTER] But there are a few things I do care about. I care about - whatever happens – removing some of the unnecessary barriers, or even going further and helping enable whatever the next set of regional transmission is. So, to me, competition is an issue. I do think it has, right now, a negative effect on our ability to get regional transmission, but, if we can solve some of these other questions, maybe we'd be having a different conversation. But, to me, we should be talking about, what is the value of transmission? Right? We're not talking as much about resilience anymore, but if we care about it, let's come to a common definition on how we value that, because that's not something we do in this industry. We've been using, you know, adjusted production costs for, you know, a couple of decades. We've got to come up with whatever these new metrics are for the value of transmission, and I think there's room to help with that. I think bridging regional differences would be helpful.

So, you know, my official position is, let regional differences bloom. Everybody's a little different, but the reality is also that if you have, you know, PJM that has a different approach to how you plan for a changing resource mix than MISO than SPP, you're not going to just bridge that gap overnight. So how do we think about that? And those challenges are much deeper than, "Just change your process." Right? Harkening back to my seams discussion, how do non-RTOs think about the usage and value of the transmission system, versus RTOs?

So I guess I'll conclude by saying, to me, the real questions that we should be focused on are really about, how do we get this necessary transmission built? And I think that if we focus on some of those more meaningful questions, we'll get to those overall objectives. Thanks.

Speaker 3.
I was laughing this morning because I said to my colleague, who is the one who normally comes to these meetings, "So your idea was that someone needs to come talk to a bunch of economists about why competition may not be good, so you picked me." [LAUGHTER] I understand. I've been in this position before. I spent a lot of time in DC, and nothing is ever all one way or another way, I guess, is what I would say. And I do appreciate the opportunity to be here.

I'd like to start out by just taking a big step back. Okay? Order 1000, at least in part, was driven by the fact that there was a sense that transmission was not being built to address transmission service requests; that incumbents were exercising some sort of market power by denying entrance, because they would not build transmission. Now there were regions that were already addressing that. SPP, for example, had a time-limited ROE (return on equity), where, if the incumbent didn't build within a certain period of time, others could step in and build it. The sad tale, I think, on Order 1000 is that the very regions that were where these problems existed, by and large, aren't doing anything under Order 1000. And so what we have is, you know, all the nonorganized market regions have no sort of competitive processes and have limited regional planning, and then, within the RTOs that have organized markets, there are states which have begun opting out through their state legislatures passing legislation on ROE protection. And so you can see there are some of those in MISO, some in SPP, and Texas right now is beginning to look at similar legislation. And you'll probably be confused, because you're looking up in New England and you're like, "Wait a minute, those aren't ROE areas." Well, I just put that in there because there are regions who are doing some sort of competitive process, but they're not really Order 1000 processes. There are RFPs for public policy projects that are being initiated, oftentimes bundled with generation; so off-shore wind, hydro coming in from Canada, and so, while there is some competitive component to this, you know, particularly in New York, which is a single state RTO, it's a much different process than what we're thinking of when we think of these sort of bidding processes, and the states have a lot more control. And I think that Speaker 2 probably made a good point, which is, you know, there are a lot of states which aren't necessarily buying into this value proposition, and some of that may be a control issue, some of it may be they just don't know what the benefits are – I can't say, I would only be speculating – but I do think it's important to note that we're moving in a direction where fewer and fewer people are opting into competition, not the other way. And so I think that that's an important backdrop for the conversation.

As these quotations on my slide illustrate, the RTOs are in a position where they're doing a lot of things they never did before. And, at least at the technical conference where these quotes were from – which was a number of years ago at this point – there were a lot of questions about, well – who is in charge of what here? You know? Who is doing what aspect of this process, and how does it work, and are we really equipped to do it?

I want to disabuse you of the notion that nobody thought about cost containment until Order 1000. This slide is actually from Brattle [LAUGHTER] - a 2011 report where they basically go through and talk about how people were looking at cost containment.

The issue of estimates and how people were sticking to estimates has been an ongoing concern for many, many years in RTOs and, generally speaking, based on the utility model, I get that, economically, there's not an incentive to control costs. Right? The more you spend, the more you earn. That said, there are many processes, and these have evolved since 2011, for reevaluation of projects if you go above the cost estimate. There are many RTOs, like MISO, that have very regular reporting requirements for project cost estimates and any changes. SPP had a bandwidth where they allowed some variation, recognizing the difficulty of estimating costs, but then, you know, basically said, after that, we can reevaluate.

Now, these cost containment mechanisms had the exact same problem that Order 1000 has, which is, okay, you went over, so what do we do about it? Nobody has an answer for that. We all know it's bad. (Okay, maybe it's not bad, maybe there are reasons for it.) But who enforces it, what's the penalty, what happens? Nobody really knows. And so it's primarily, I would call it, public shaming. What we're trying to do is say, okay, we want to push people to be more prudent. And I would also say that I take some exception to the idea that there are really no controls on costs. If you have a formula rate, your formula rate protocols allow informal and formal challenges to everything you do, essentially. It's not just about what data inputs you put in; it's how you calculate taxes, how you capitalize. It has become, at least in some areas, a complete fishing expedition to find anything or everything that customers want to question. Now, it may be that ITC has a more robust process there, because we don't own the generation or the distribution, so, if you're an incumbent and you own all three, maybe you're not asking yourself a lot of questions. I don't know. But the point is, there are processes in place, and customers don't seem shy about using them. And so I do think we need to not make claims that nobody was really thinking about costs until Order 1000. That's not true and it continues to be a concern.

Okay, so here's a key point I wanted to make, and this goes to Speaker 1's comments about the cost estimate projected savings in her report. There are a lot of different points at which we do estimates in the planning process and, because of that, you have to be very careful what you're comparing. So, when you look at that project initiation, and you see the huge bandwidth of how right that estimate may be, those are what we call kind of planning cost estimates. Right? And nobody's really expecting them to be close to accurate. When you talk about where we are in Order 1000 and what those bids are, those cost estimates are final project design estimates, and they're much more accurate. And so, what's the difference? Well, the difference is probably, you know - a project initiation cost estimate costs $15,000; a final project design costs a million dollars. That's what the difference is. And so what Order 1000 has us doing now is, instead of everyone doing sort of these initial processes and then, over time, gradually, as they know information, refining their estimates, we have a lot of people spending a lot of money to get final project designs, and there is a question about whether that is inefficient, because that's a lot of money. And I do have some concerns on the Brattle study that Speaker 1 was quoting. It's not clear to me that we're comparing apples to apples. I think that some of the data that she looked at were more initial project estimates for incumbent projects, versus the design-level estimates for the Order 1000 projects, so of course there's a bigger difference. And I would say that ITC has done some analysis, and our numbers in MISO come up with MISO being about 4-6% above estimate, and, in New England, about 1.5% above estimate. Those numbers will be released soon. We have a whole document that explains it, so you can all look at it and then ask me what the variable numbers are.

The other problem is (and Speaker 1 mentioned this, but I just want to highlight it) that, with the sponsorship model, it is very difficult to determine, you know, what you're comparing to what, because – and particularly in PJM – those estimates come in at different times, and the RFP changes over time. So it isn't that easy to just go, here's one, and here's the other, and here's how the difference is. So we're doing the best we can with the numbers we have, but I do think we need to take a little bit of caution before being too critical.

I would also say that, you know, we have a very large number of noncompetitive projects that we looked at to see if they were close to estimate, and we have a very small number of competitive projects that we looked at, and, just by fairness, you know, the results might be different in a bigger sampling. Right?

And then, finally, I would say that not all projects are created equal. So even if you decide, yeah, the cost estimates are really different, and competition is better; well, if you look at SPP, just as an example, only at the reliability projects with information that's publicly available, the cost estimate difference is negative – it is below estimate. So just expanding to capture reliability projects may not be where the customer benefit is. So we can't just make an assumption that, because of estimates on these bigger projects or where they are, that it would necessarily mean that bringing in smaller projects makes sense.

Moving briskly along – this slide is just making the point I already made which is how, over time, things become more firm.

Past experience. So, one thing we can look at is CREZ (Competitive Renewable Energy Zones). CREZ, of course, was a competitive process – it was a single state process – and we all looked at it as being a relative success, in the sense of connecting things. What we also see is that it ended up being 40% more expensive than they thought it was going to be. Now, in large part, that was due to routing changes. I think something like 600+ more miles of transmission was required than originally planned, but there were other things that changed. So I guess I would point out that competition in and of itself doesn't guarantee that costs aren't going to change. All it means is that maybe you're getting a lower project cost to begin with.

And that takes me back to my point about the problem of, if you go over that project cost, what happens? So then we get to the cap issue, because the other argument is that, well, the good news is that a lot of people are beginning to put caps on, and so that will make sure that we have more rigor in enforcing cost estimates. And the problem is this, as I see it – and this is from a developer point of view - there are things you know early and there are things you know late, and it doesn't matter who is building the information in, the information comes at the same time. And so, when I look at some of the exclusions or exemptions that we see in bids, it makes perfect sense to me, because, of course, you want to exclude routing changes, right-of-way costs, things that you're not…commodity prices…80% of transformers are steel. Did I know the President was going to put a tariff on steel? Am I held accountable for the fact that the commodity price changed? Nobody who does business does things that way. They put in pluses or minuses to account for things they know are likely to escalate. So one of the questions you really have to ask yourself, especially given that a lot of these competitor projects haven't been built yet, is, will they actually have the same escalation, it just hasn't happened yet? And many of them will fall within an exemption. Now, there are some caps that are a little different and a little bit more binding. Certainly NextEra put out one where they said they wouldn't recover any return on anything above the cap, which is a very bold thing to do, so I don't know where you are, NextEra, but congratulations. [LAUGHTER] But they also put a 10-year cap. Well, a 10-year cap is great. ITC actually looked at a 10-year cap, because you can actually project, with some level of certainty, 10 years, The problem is, what happens after 10 years? There's no cap anymore. So could you defer costs and push it through on year 11? Probably.

So, you know, there are all different ways to manage this, and I think that state regulators and people who are looking at this – the RTOs – need to make sure they're not in a shell game here. We need to make sure that you're actually getting some cost benefit, and just not the appearance of a cost benefit.

We also talked about the issue of what's getting built and not built. And I think Speaker 2 did a pretty good job talking about this, but I think we have to put this all in context. Order 1000 came right at the same time that the regions were already initiating major buildouts or were in the process of major buildouts. MISO MVPs (Multi-Value Projects), SPP Highway-Byway, New England's buildout, Texas CREZ; all of that's going on. MISO is putting into service - our project is the last MVP that will be put into service this year, so we're not even at the end of that build cycle yet, so it shouldn't be a huge surprise that we don't have a lot of big projects that are fitting into the competitive category. In and of itself, there's nothing nefarious going on.

I will say, ITC does believe that Order 1000 is negatively impacting the planning process. We do think it's causing compartmentalization, and that it's driving some less efficient solutions. That said, when you look at the MISO footprint or the SPP footprint where we're located, what's the hugest driver? The generation of interconnection queue. It's not because we manufactured it, it's just the way it is. And I think Speaker 2 made this point, and I would make it too, which is, let's not lose sight of the forest for the trees here. You know, connecting wind, which is hugely more economic than a lot of other generation that's currently online, is going to save people a lot of money. So creating processes that slow that process down isn't necessarily a good idea for customers. Time equals money. Right? And I would say that there are probably some entities who maybe don't have competition in their regions. They come into our regions, and they like the fact that they can compete, but they also like the fact that the process is really slow, because maybe it gives them some market power, because, while all of this takes forever to play out, they're already in the market. So we have to be cognizant of the fact that there is more than one way to play to your advantage in this game.

I would say, too, though I don't pretend to be an expert on this and what other countries have done, that one of the biggest challenges we have is that siting of transmission and all the rules around that are done by the state, not by FERC, and then FERC comes in and wants to put a competitive procurement process in place for the thing that the states are in charge of regulating. Look at Iowa as an example. We have assets in Iowa, along with Mid-American, you know, they want everything constructed so you can double circuit – even if you don't double circuit to begin with – because they think that, you know, right sizing is a good policy. Well, is that project going to be the most cost-effective project in a competitive process? I don't know. And so then you start wondering, well, is that why the states don't like this, because they have certain things they want to require, but maybe aren't able to, if cost is the main driver? And make no mistake about it, cost is a big driver here. When you look at the criteria, MISO has 100 different points you can win – is it MISO who has 100 and SPP has 1000? I can't remember.

So you look at that – I could tell you right now – take like 80% of those right off the table, because everybody needs them. Okay? So then you're down to, like, sticks and bones about, well, which percentage is differentiating this person from that person? And Speaker 2 knows better than I do.

Now, there are open solicitation projects, like New York and PJM, which are much more robust – a whole different kind of ball of wax – but in those places, it's really hard to judge costs, because you're not comparing comparable projects. So, you know, with respect to this motivation towards, you know, how can we control costs? Is Order 1000 a way to control costs? I would say it can control costs, and it could be useful in certain circumstances, but we have to be careful where they're deploying it.

Just as an example, SPP had a project which I think most of you know, the Walkemeyer project. It was a ten million-dollar project. It cost five million dollars to administer the process and, ultimately, the person who won the process cancelled the project. That's not efficient by anyone's standards. It's also not unique. California had a project in 2015 which they awarded to a foreign investor who subsequently went bankrupt. As of February of this year, they've announced they're no longer going to move forward with that project and, in fact, there's been no solicitation out of California since 2016. And then I guess I have to throw in Artificial Island – say no more. So, you know, our experiences haven't necessarily been all great. Okay?

So while on the face of it these projects may look like, yeah, we're saving money and we're doing this and we're doing that – some of them never even got built; some of them are going to get built and are probably going to be above what we think they're going to cost. So there's a lot to consider here, and it is a complex issue.

On transparency, we talked a little bit about the rate protocols and how people can see transparency. I can't speak for every RTO, because every RTO is different, and I'm not an expert on PJM or some of the other RTOs--New York and what not--but, generally speaking, stakeholders in the MISO and SPP region have a lot of visibility into what we're doing. If it's a project that is generated by a NERC reliability standard because they run a load flow and you trip something – yeah, it's not a big process because everybody knows you have to fix it. Okay? Now could that be a more robust process? Probably. I do think Order 1000 may be compartmentalizing how we think about these things, because instead of a top down, which would be like an MVP-type approach, we're doing a much more bottom-up approach, which may not be ideal for optimization.

And then my last pitch is just on ROE bidding. Most regions only bid project costs, but there are regions like MISO and SPP that include full revenue requirement bids, which means you're bidding your regulated rate of return. Some of you may be familiar with the fact that ITC filed the petition at FERC which ultimately was dismissed, but, subsequently, there was a technical conference to talk about this, along with a lot of other issues, and I continue to get no kind of satisfaction on where we're going with this, because the reality is, we have a cost of service model, and a part of that is that you get a certain rate of return that's determined through the DCF methodology at FERC, which, by the way, most of us have been in litigation on for years. Right? So, I bid a project, I put in my ROE, maybe I even downgrade my ROE, because I'm desperate to win the project, and then I still have to go to FERC and have a whole DCF analysis to figure out if it was the right ROE. Why am I bidding it? It's still regulated. It makes no sense. There's no upside for the developer. All you can do is bid below whatever your current regulated ROE is, and there's only downside.

I would also point out that there's no durability, and I think this is something NextEra tried to address in one of their filings that ITC has talked about. Anyone can come in at any time and change your ROE through a 206. So you want me to build an asset that's going to have a life of at least 40 years, probably longer, and I have no guarantee of how much money I'm going to make off of that project, but you want me to bid and be cost contained and do all these other things. How is that a desirable model, and also, how is it a sustainable model? I mean, one of the things we need to think about here is the risk profile we're talking about when we talk about electric utilities. We can contain costs, and we can do things that are reasonable, but the minute we start saying that we're not going to let you recover prudently incurred costs, your whole risk model shifts, and it doesn't seem fair, at least, that all the risk should just shift to utility shareholders. It does seem as though you could do some PBR-type approach where we share the risk on the upside and the downside, kind of like what New York does.

There are a lot of different ways to approach this, but the bottom line is, we have to think about how much capital costs, we have to think about what the states want, and ultimately we have to think about how we get the transmission built, which, I guess, is sort of the message I've been trying to deliver to people, which is, let's not get caught up in the elegance of our model at the expense of what we need to get done. And FERC has a number of proceedings that are going on: the ROE generic proceeding they just initiated, their incentives proceeding. They have other things that they are working on, like generation queue reform. All these things are meant to build more transmission, and then, at the same time, they're turning around and going, "Yeah, you know, you need to bid your ROE, so, you know, I don't know why we did a whole proceeding, and also no incentives, because that won't get through on the competitive process."

And so there's just a lot of questions here about how everything fits together for me. But I would close by saying this; I think that we need to get more information; I think that we need to recognize that there are opportunities for some benefits here, but just saying, "Well, we should spread it to every project everywhere, and that will fix the problems with this process," really doesn't make a lot of sense to me. I think that there are some things we have to fundamentally work out, and I think that we need to focus on the projects where we can get the most value for customers, because this process is, to quote Mr. Joskow, "Costly, complex, and time-consuming," and so we certainly don't want everything having to go through that process.

I don't know how you decide what goes and what doesn't go – I'm sure we can have a lovely debate about that. SPP put in a proposal that was a dollar threshold, and the Commission came back and said that was – I can't remember - was it arbitrary, capricious, or both? Well, whatever the case may be, I guess my question is, well, what wouldn't be?

And then there's the concern of gaming. Well, of course there's going to be concerns about gaming, because if you set a threshold, people can always game. And so one of the questions I have is, if you look at that map from the beginning of my presentation, and you start talking about what projects are in and projects aren't, and gaming the system, maybe what we need to do is create a system where people feel they have got a fair chance, and they feel like it's a good system, and then more people would be less interested in gaming. And I think that that's the challenge here, because we need to build some transmission. There's no doubt about it. All the signals in at least our part of the country show that. And we're not going to get big projects out there unless we can kind of get through this and how it relates to cost allocation and all the other things Speaker 2 talked about. Thank you.

Clarifying Question 1: Speaker 3, you used the CREZ as an example of a failure, and I'm wondering, when you used that example, whether you considered that that was actually a public policy, "Build it and they will come," project; it wasn't driven by any need, as you described, like the queue in MISO, or whatever. And, too, the costs were socialized there, so there really was no cost control. I'm wondering, when you use that as a paradigm of a failure for a competitive project, whether that actually plays into it, and distinguishes it from other competitive RTO projects?

Speaker 3: Well first of all, if I conveyed CREZ as a failure, that wasn't my intent. I actually think CREZ was a success. CREZ is very much like what we did in Michigan in our last MVP we're building, where you identified the areas where wind was, and then you had a project build so that people could get connected quickly. We support that model. My only point in pointing out the CREZ was that it was a competitive process, but there were still cost overruns. My only point was that, you know, even in a competitive process, where people are bidding and trying to be the most efficient they can be, there are still costs you can't anticipate. That was my only point.

Questioner: And do you think that was because of the structure of the bidding? In other words, because it was socialized, and people didn't see the actual cost? In other words, would there have been a way around it if there had been cost containment provisions as part of the competitive procurement?

Speaker 3: Well, as I said, it seems to me that one of the major escalators for the CREZ costs were routing changes and additional line, and so, unless you're going to say, "Well, you have to bear all the risk of a routing change through some kind of cap," I don't really know that any bid could have fixed that problem, and that was sort of my point. In my later slides, there was information that comes very late in the transmission development process which is part of the reason why estimates are challenging. And so you can get more refined. Order 1000 has driven refinement in cost estimates; people are getting better at it, and they're more aware of it, but, ultimately, there are some aspects of the way transmission is developed, particularly with the state jurisdictional piece (Texas is a little bit different because, you know, you're not FERC regulated) that do lead to these challenges. And so my only point was, I think CREZ is a success. If we all did CREZ, I think it would be great. But I don't think that we can just say that competition solves all these problems, because these problems are going to exist no matter who builds it or how they get it awarded.

Clarifying Question 2: You mentioned the Walkemeyer project, which you said had a ten million-dollar cost and was five million to bid? What's that bid –

Speaker 3: The process was five million dollars to get a bid put together for that.

Questioner: Where did you come up with the five million?

Speaker 3: That came out of the report out of SPP.

Questioner: The SPP report, okay. I thought the actual SPP costs were much lower and were all borne by the bidders, so it wasn't a cost to rate payers…

Speaker 3: Well, I guess you're differentiating costs between whose paying, and my point was just that the total costs were five million dollars. I guess I would question, if that project had gone into service, whether rate payers wouldn't have seen some of those costs, because we do see utilities creating regulatory assets through which they will then pass through deferred costs later, and then, of course, if there are cost overruns, those usually get put into rates as well. So I don't think we can just assume that because a developer bears costs, it won't ultimately find its way into rates.

Questioner: On slide 3 – and you said this was a Brattle slide on the pre-Order 1000 cost containment, one identifies the MISO 80/20 cost-sharing, and I just wasn't sure if that had been voluntarily used for any non-Order 1000 projects.

Comment: I'm a New York person – don't assume I know the answer to this. [LAUGHTER] The 80/20 …maybe back in 2011 somebody thought that's how the dust was going to settle here, but I don't think that's how the dust settled.

Clarifying question 3: A quick question on your CREZ numbers. That seemed like a big increase in costs. I thought that the project went back for an increase in scope, and so I'm wondering if your numbers were apples to apples in terms of the amount of wind that they were trying to actually connect, versus actual cost increases?

Speaker 3: Well, I just took the numbers directly from the CREZ report on, you know, what the initial numbers were versus what the ultimate costs of the projects were, and I did indicate that a lot of the change was resulting from siting changes, so I think siting would encompass change in scope.

Questioner: I think they also went back to just trying to connect more wind. I'd agree with you that re-routing would be an increase in costs, but, if you're initially going to connect 5000 MW, and then you said, "Hey, you know what, let's build more and connect 7000 MW," that might not be an apples-to-apples comparison.

Comment: That element existed, but I don't think you can completely attribute it to that. So, in fact, the Commission has kind of opened up a rule-making or investigation, because what they found is that the bids that came in for CREZ, be it a competitive bid or an assigned one, it comes in at one price and comes out at 6X, or something like that. So they are looking into that, but there were also add-ons to the original CREZ; however, that does not explain the delta between what it's actually coming in at and what it was originally estimated at in the beginning.

Clarifying question 4: To your point on risk-sharing and the escalator provisions, my question is, what are the implications for how risk will be managed? What have been the lessons learned so far with how risk has been managed when we've had more suppliers do it? Is this analogous to how we saw risk incentives change on the generation side, which we have more history with? And what are the implications for ROE policy, going forward? Because, typically, if you, you know, de-risk a lot of investments, then you should see subsequent changes in ROE. Thanks.

Speaker 3: Well, I believe New York has a proposal that no one's ever used, I think, that talks about risk-sharing, but also talks about potentially reducing the portion of ROE to address that change in risk. Obviously, there's a connection between the two. I guess I would say that, right now, we have a ROE that's regulated that we potentially can bid. We can also bid below that ROE, presumably, and many people do. And so then the question becomes, well, how much risk on top of that do you add? And so I guess my point is only, if every major project, and perhaps even more projects if we expand, gets put into this competitive process, then I think we have to assume that the profile of the utility becomes more risky, and, if it becomes more risky, then we probably need a higher return.

I hear a lot of people trying to make analogies with generation, but it's a very different thing. Generators have all kinds of ways to hedge their risks, both financial and otherwise. They're not denied access to the market, because we're not bidding on who constructs the plan; we're bidding on the output of the plan. Many of them have a big upside, because of the clearing price, and so they get more than cost of service. Under no scenario do I see this process for transmission giving us above cost of service regulation. It's really a property right, almost. If you don't win, you're not in the game. And so what we see when we go to the street, for example, is, you know, where we could have said before, "Well, within our footprint, these are the projects that are in the MISO plan, and so we're going to have this much growth," as an example. We can't do that anymore. We can point to reliability projects, we can point to other projects, maybe, that we've won, but we can't point to some of these larger projects; the result of which, of course, is that the growth numbers for utilities are down, among other reasons. Okay? But the point is, it's part of it.

And then the funny part of that is those growth numbers go into the DCF calculation, which gives you a lower rate of return. It's all connected, and so pulling on one thread kind of takes you to another. And so I do think that, if you're going to extend Order 1000, you're going to have a whole scenario where people are losing money because they're eating costs on things, they don't win bids, a variety of other things. How do they ever get their money back? Because no model can exist where, you know, you've got a cost of service for your project, but you never get above cost of service to make up for the money you lost someplace else. And, I mean, there has to be some kind of mechanism there.

Speaker 4.

Thank you for the opportunity to provide a few thoughts from the LS Power perspective on the state of Order 1000, its benefits, and then also areas for improvement. We're excited as we look ahead in terms of what the opportunities for improvement could look like, but we also are excited from the vantage point that we see that when competitive windows occur (and granted, there have been limited competitive windows), we see that commercial innovation occurs, as well as technical innovation. And, in our mind, a big headline from Order 1000 and these competitive windows is its bringing commercial innovation that wasn't present in the bidding process prior to the Order 1000 process.

We look at the various cost caps that are being proposed, and they are real and enforceable. The cost caps are in the developer agreements, they're filed in the rate case at FERC, and that's a fundamentally different model than the world of cost estimates, and we see that the move toward cost containment and commercial innovation that these competitive windows has triggered is a positive development.

In the most recent Order 1000 window in MISO, if you look at the excellent selection report that MISO released on that competitive window for the Hartburg-Sabine project in east Texas, what we saw was that, of the 12 bids that came in, 11 of the 12 bids bid some form of capital cost cap in their bid, and that included not only the nonincumbents, as you would expect, but it also included incumbents as well. We're seeing, in these competitive bid processes, that the incumbents and the nonincumbents are bidding in cost containment. In the recent MISO bid – and this is not unsimilar to what we are seeing in other markets –we saw four out of the eleven bidders forego AFUDC (Allowance for Funds Used During Construction). Another nine out of twelve bidders forego CWIP (Construction Work in Progress) and other ROE incentives. Four out of the twelve bidders took the routing risk. We saw ROEs come in a full 100 basis points lower than some of the MISO average ROEs. We saw 11 out of the 12 bidders provide some form of certainty in their capital cost structure. We saw seven out of the twelve bidders bid some form of an O&M cap. That's a new development that's occurring in some of the MISO processes. And then we saw five out of the twelve bids bid some form of annual revenue requirement caps.

And this is just from one competitive bid in MISO, but we see this as what's happening in the vast majority of all of these competitive bid processes, whether or not it's in PJM, whether or not it's in California, whether or not it's in New York or MISO or SPP. And the marketplace - when there are competitive opportunities - is responding with commercial innovation, which is basically giving the potential to shift the commercial risk on these projects from rate payers to developers. We see that as a positive sign.

In addition to the commercial innovation that we see, we also observe that, in the last two years, the voice of the consumer is also growing and supporting competitive transmission. I might highlight that in PJM this last year, 84% of the Members' Committee supported more mechanisms in PJM to look more robustly at cost containment related to competitive transmission, and my company certainly saw that as a vote of strong support within the membership of PJM for more competitive transmission.

We see continuing signs that it's not only the new entrants that are saying, "Hey, competition is good," but, more importantly, we're see increasing signs that the consumers are saying, "This is important policy, our transmission costs are going up and we want competitive pressures." We look at the Brattle study, as they are walking through the results of it, and we see it as a sobering assessment of the state of Order 1000. When we are talking about numbers that say that only 2% of the FERC Form 1 transmission that's built in this county and is competitively bid, that number is just too low. So my company looks at the situation and looks at the Brattle report and we say, "Well, the clear response to that is, let's increase the number of Order 1000 windows; let's increase the opportunities for competitive windows." We think it's a clear record, and we look forward to seeing the full report.

And now we look at the situation and say, "Let's fix it." And our focus is saying, how do we reduce some of the carveouts to Order 1000 ? How do we increase the number of windows? How do we decrease the number of exclusions? Clearly, the issue with supplemental projects and the growing number of locally planned projects has to be part of the solution as well. There are too many carveouts, and there are too many end-runs going around order 1000.

And so I would simply conclude, in terms of the comments, that we look at 2019 and forward and say, the record is being clearly established that more competition is helpful, and that it's now time to expand and fix Order 1000. And fixing Order 1000, in our mind, means expanding competition, and the record is there for it. Thank you.

Comment: Can I just add one quick comment on that? On the O&M issue, I think that's an interesting point, Speaker 4, because, you know, generally speaking, a big chunk of O&M is an expense. We don't actually earn on it, and there might be negative aspects to deferring O&M. So I just put that out there as one comment.

Speaker 4: I would say, in response to that, in terms of O&M caps, that's an issue that's coming up in various markets. Some markets are saying, "Hey, we're excited about bidders bidding in caps on O&M," and other markets are saying, "We're not excited about it." And so, for instance, specifically in PJM, there were clear provisions in the *Tariff and Business Practice Manual* that said, please don't bid in O&M caps into this process. In contrast, if you look at the tariffs in CAISO, SPP, and MISO, they look at total annual revenue requirements as part of their bidding process, and so the issue of O&M caps has become a bigger issue in those markets. And we're particularly seeing the topic relating to O&M caps come in relating to bids on substations, and that seems to be where some of the most lively conversation is occurring.

General Discussion.

Question 1*:* How should the RTOs and ISOs weigh the overall cost of a project containing a bid, relative to offers of cost containment and certainty? For example, if a bid is higher, but it contains more cost containment guarantees, should it be favored, relative to a lower cost bid, and how should that be evaluated?

Respondent 1: Sure. So, you know, 100 points aside, it's not all scientific, but the way MISO thinks about it, at least, is we do a lot of scenario analysis around that, and then we use the results to make our final judgment, because even within the costs, you can understand what is your kind of realistic expectation and what could happen, and then how would that all play out, and then we use that to make a decision.

Questioner: Okay. And this is, again, open to everybody, but what do you all see as the role of the various entities? Is it up to the RTO or the ISO to monitor if a project is selected, of all the guarantees, the things that have been put in along the way, basically tracking any enforcement of various commitments made in a winning bid, and what's the role of FERC?

Respondent 2: So I nodded vigorously when Speaker 3 said that it's not really clear who is going to enforce any of this. [LAUGHTER] The position MISO has taken is that, ultimately, this is a question for FERC. So, we try to make transparent what is happening. We get regular status reports and updates and things, but our expectation is that, ultimately, if somebody has a concern, they're going to take it to FERC, because, at that point, the rates are on file at FERC. FERC made the decisions. The agreement is on file with FERC. So at least for MISO, that's how we theoretically solve the problem. I don't know what other areas are doing.

Respondent 3: From an LS Power perspective, we see that the issue of enforceability is clear from the standpoint that, when these cost containment proposals are proposed in the competitive bid process, it's not just a PowerPoint slide. The bidders are putting into the RTO the actual legal language that accompanies the cost containment bid. And so part of the evaluation process that the RTO uses in their selection process is looking at the actual language, the actual legal language that goes into the agreement between the developer and the RTO if they're selected, and that's filed in the rate case at FERC. And so we see that in our view there are two places of enforcement. If the developer does not comply with their cost containment, they are essentially, first of all, not in compliance with their developer agreement that they've signed with the RTO, and there are implications for keeping the overall project from that vantage point, but, secondly, it's also filed in the rate case. Basically, it's part of the actual rate case, and FERC uses that in administering the rate recovery.

Question 2: As a company, one of the things that we've struggled with on Order 1000 has been what the ultimate objective of the elimination of the ROFR provisions actually is, because, 10 years ago, I think, ITC was one of the biggest advocates for the principles of Order 1000 around the need for regional planning and the need for some type of regional cost allocation. At the time, if you would have asked us, you know, what are the top 10 things that are inhibiting transmission from being built, the elimination of the right of first refusal probably wouldn't have even made it on the top 10 list, because transmission was actually starting to get built at that particular point in time, and I think Speaker 1's slides actually reflect that.

The challenge that I think we have today is going back to the question, what was the original principle of Order 1000? Was it to get more transmission built regionally, or was it to have these processes established in different RTOs or different regions of the country that were going to make us get better cost estimates for transmission? I would argue it was actually the former, and not the latter. And, again, I think it's reflected in Speaker 3's slides that, when we estimated costs 10 years ago was, you started with a high-level planning cost estimate, and you narrowed the bandwidth as you got closer to the actual final cost estimate for the project.

So, as a company (I think I said this), we were very schizophrenic. I think we're getting a little bit better [LAUGHTER] in our mental perspective on this, but from the perspective of, should we support Order 1000 and these provisions? Should we look to change it? Should we look to modify it? Over the course of the last 10 years, I think we've finally settled on the fact that Order 1000 isn't providing the type of benefits that we seek from a regional planning perspective. And maybe there are benefits from the cost competitive perspective but, again, 2% in the amount of costs that we've seen just isn't really, I think, getting it done, from our perspective, and that's one of the reasons why Speaker 3's comments are the way they are.

The other thing I would say is, we have this Mongolian barbecue approach to Order 1000 and, I don't know if you've ever been to a Mongolian barbecue – you stand in line, and you make your dish based upon what you think tastes good, and you put it in a bowl, and you stand there and they cook it for you. I can tell you that, most of the time, it's crap – I mean, I wouldn't eat half the things the people in front of me make, or behind me, but I like mine, because I actually put the stuff in there that I like. I think we see that also in the RTOs. They've actually put in place these planning processes that, I think, are reflective of the regions, but, again, I think those differences that Speaker 2 mentioned are really what are the biggest inhibition to getting these cross-border projects built. I actually was going to ask a clarifying question, Speaker 2. A number of years ago, you presented seams issue, and I was just going to ask you for an update as to how that was going? [LAUGHTER] But nevertheless I think –

Respondent 1: Still not solved.

Questioner: Still not solved? So, how do you see Order 1000, or reforming Order 1000, in terms of getting back to that first principle of getting more transmission built, if it's truly needed? Because I think, again, you know, the gamesmanship and people pulling back, and all of the exceptions that were on the list are just indicative of the fact that it's not really working the way it was originally intended.

Respondent 1: At least for me, that's why I think that the competition question is maybe a little bit of a distraction, because, at least from the RTO perspective, if you think about our mission, which probably getting the right transmission built to provide the overall value, access to cheaper resources and things is probably our first objective, so it seems like what we should be focused on is, you know, cost allocation. Right? How can we get to a better place on cost allocation? We all want to come to agreement, and we go through all this work to do it, but, on the other hand, it's really folly to assume that, you know, in MISO, 200 members are really going to come to agreement on cost allocation that will have a meaningful impact on transmission building. I mean, I think that's just reality. That's where I'd focus.

Question 3: I'm trying to digest that last comment, [LAUGHTER] but it's actually related to the question I wanted to ask. And thank you for the presentations, I found this actually quite interesting, and there are a lot of issues that were raised. For Speaker 1, on that one table where you had the different areas, the RTOs and so forth, and the types of projects that are exempt and not exempt, and all the other kinds of things that are excluded, when I was looking at that, I was happy to see that when the costs are going to be absorbed by the utility and just put into their rate base, that's exempt from this process, and they don't have to worry about that. That's a good thing, because then that's matching the benefits and the costs and the people who are the beneficiaries, and they're going to manage it better, and we don't have to worry about that problem. So, all the problems we're worried about here are things where the costs are not allocated that way, not absorbed by the people who are proposing it, and you're going to be making people pay for it who don't want to pay for it. That's the fundamental problem.

So then we go back to the fundamental principle of Order 1000 (I hate to bring this up, but I can't control myself), which was that beneficiaries pay. So then it gets to Speaker 2's issue about cost allocation. And I think there's a quite simple conceptual answer to Speaker 2's problem. My conceptual answer would be, first, for projects like this, where you don't have people doing things and paying for it themselves, including merchant projects or locally developed things, but where it's a broad, large project where you're going to force people to pay for it who don't want to pay for it (and that's fundamental to all of this), you have to have, first, something that provides some control over that process, so you need a cost-benefit analysis. Right? Not just a cost analysis. You need a cost-benefit analysis, and Speaker 2 asked what we would do about the metric here, and then she dismissed the metric that seems to me completely obvious, which was the production cost avoided, historically, and she said that we need something else to get to the values.

So, my two-part question. Do we have any information on how well the cost-benefit analysis is going, and are we actually doing cost-benefit analysis? And then, secondly, how does this connect to cost allocation? And I've written about this at length and been completely ignored, because nobody likes the answer. [LAUGHTER] But I think this is actually a conceptually simple problem. I think it's a politically difficult problem, because it will put Speaker 2 in the hot seat, and she doesn't want to be. [LAUGHTER]

Respondent 1: I guess what I'll say for MISO is that, when we are looking at projects that just really aren't local, but are for local needs, we do do a cost-benefit analysis. And I think that, conceptually, is straightforward and works pretty well. Part of it is the political problem, because one of the things you run into is, don't give me a benefit that I don't want. And that's true, by the way, even for adjusted production costs. So in my simplistic example of Iowa giving zero marginal cost wind resources to Mississippi, Mississippi would say, "Eh, I see your cost benefit, but I don't believe it, I don't want it." That's your political problem. The problem I see with the adjusted production cost in the current world is, if we're headed (which we are) to a much reduced marginal cost (in some cases, we're at zero or negative, between the renewables and the low gas prices) the benefit that transmission is bringing is not really about leveling those prices. So then the question is, what is it? And, to me, that looks something more like reliability. But in the reliability space, to date, we haven't really provided a cost-benefit analysis. There's not a measure by which we look at that. And that's what it feels like is missing today, because the truth is, in Iowa, they would like to have their lights on, you know, even when there's lots of wind, and, if we end up with a lot of solar in Louisiana, they're going to want the same thing. The question is, how do you figure out who is getting what benefit and get it to them? So that's the problem I see.

Respondent 2: I would just add that one of the challenges we have is that we have categories of projects, and when we talk about what cost-benefit analysis we're doing, it's based on what bucket you're in. The only time we really breached that was when we did the MVPs, and we sort of looked collectively at all the benefits. So, you have a reliability bucket, you have the economic projects, you have the generator interconnection, you have the transmission service. And so one of the challenges with understanding the value of the transmission is that the benefits actually aren't in neat buckets. But no one wants to deal with that, so we just create the artifice of saying that they are. And so we've been more successful in driving larger projects and getting more infrastructure built when we've breached the division between those categories and said, "Well, let's look at all the benefits the project provides." And I would suggest that, if you want, you can look at the Wires website. There is a study that Brattle has done on the value of transmission and attempting to quantify different values like reliability, because the reality is that it's very difficult to get picked. Okay? Generation could get built much quicker. It's usually a more go-to solution. We don't even get in the game if the load forecast is reduced because of alternatives--DG, whatever it may be, such that the load doesn't suggest that you need to build.

And so one of the problems we have to think about, too, is benefit over time, and that's always been a tricky piece of this, because I could put a generator in now to solve a congestion problem but, over time, I may still need to build the transmission line. And so, are you just building both now, because it just looks better right now to do this option, or do we really need that option right now? And one of the hardest challenges we had when we were doing Order 1000 was to talk about the fact that you can't just do a slice of "who benefits right now" and say that that's how it's going to be forever, because that's not actually how the system works. Over time, who is benefiting changes. Over even weeks or days, the benefit can change. And so assigning property rights and trying to define things to that level creates a very big mess, quite frankly. And so I think, you know, MISO is able to get a portfolio of projects together and say, "Everybody gets their project," and that's how we got stuff through. And SPP had their approach.

It's becoming more complicated, though, because you've got importer and exporter states, at least in our part of the world, and those two people don't see the same things. And so I know there's a variety of things that people are looking at to try to figure out how to directly assign costs for renewables and the needs for renewables, but at some point we do have to step back a little bit and say, "Okay, it's not a secret to anyone that we've had a lot of dramatic weather, we have a lot of new threats, there are a lot of things going on in the system." I will tell you that, when our MVP gets placed into service (we're the last one in MISO), that asset will be fully utilized. So we're not overbuilding, and I think that we need to start with that understanding. At least in our region, that's not happening.

So, cost allocation is a huge sticky wicket. I haven't read what you've written, so I have to go find it now, but I would say that I think that part of the key here is understanding that people have to have confidence that they really need it. And, as Respondent 1 said, it can't just be that it would be nice to have, because having something I don't really need I don't care about. And so redefining the conversation, I think, is a big part of this, and making people understand the interconnecting nature of everything. And I think that, quite frankly, the distributed generation discussion has been a detriment to making that argument, because there are a lot of people who think that you can just sort of individualize reliability, as opposed to having a collective reliability.

Question 4: I appreciate the Brattle report, because I've been through so many of these, and a report comes out and says, "The RTOs aren't doing anything, here are the numbers," *et cetera*, *et cetera*, and implies, you know, that we're just sitting around and just handing out projects to transmission owners and not doing much else. I think the numbers mask what really are fundamental policy issues.

I'd like to sort of label five policy decisions that were made at the time of Order 1000. There were fundamental policy issues that were decided in ways that drove some of these results. And you can argue whether they were good or bad but, to me, that's more relevant than this just counting projects. Counting projects masks, to me, what is really the issue. And I'll give five policy issue decisions, as I read Order 1000, that were debatable, but were made. One was bottoms-up planning. Regions have to benefit. They're not going to do a top-down planning model. That was heavily debated. I remember those debates. It was bottoms-up planning to every region. That, therefore, leaves a lot of otherwise beneficial projects falling off the table, by just that decision alone. Number two was, I think, a recognition that owners of assets have certain rights. You can argue what those rights are, but upgrades were reserved to owners of transmission, probably because there was some concern about, if it's an upgrade, whether we're going to start sort of empowering incumbents to have CPCNs (Certificates of Public Convenience or Necessity) associated with upgrades. Okay? That's a fundamental issue that drives a whole lot of what is happening out there. Fundamental issue number three is that Order 1000 was tied to regional cost allocation. If it wasn't regionally cost allocated, you didn't have to do any of this. You didn't have to bid it out. We can talk about why that decision was made – I'm not sure I fully know why that decision was made--but that's what it's tied to; so, therefore, a whole bunch of things fall off the table.

Just two other fundamental issues. There's all this discussion about alternatives, and why don't you consider alternatives like distributed generation. The markets do that. Remember, this is not an IRP process; it's a transmission planning process. So the markets are indicating – or should be if they're working properly – whether there's a DG solution or a generation solution or a storage solution – something other than transmission. I don't think I need to create an IRP process to consider all these, because I'm already considering them. I'm sending the market signal. The last one, which I actually think was sort of the biggest problem, is one of the issues that, I think, fell off the table in the consideration of Order 1000. That was squaring the Order 1000 "beneficiary pays" standard with the standard for generator interconnection, which is "cost causer pays." Okay? Those two don't square. And I remember we raised it in the context, and the Commission said, in its lovely way, "Out of scope, get out of here, we're not dealing with that issue." That fundamentally took off the table a larger discussion of benefits.

So, any of these can be revisited and should be revisited, but I would just hope that we spend time on looking at these policy issues, instead of, "This region's good, this region's bad, who's up and who's down," because I think we're spending way more time on that than I think is worthwhile. Thank you.

Respondent 1: Even though the tables show the regions, they were never intended to be a scorecard of any kind. It was just the way that data was available, by region, because that's where the RTOs sit. And I also don't disagree.

Questioner: I just meant how they'll get played in this as scorecards

Respondent 1: I totally hear you, and I think that's very valuable feedback. I actually agree with some of the previous conversations about how we do need valuable transmission to get built. We need to get that done. And I also agree with many of the things said about cost allocation. I actually agree with Speaker 3 about how many of these projects have multi-value, regardless of what you call them, whether they're reliability projects, economic efficiency projects…We know that many transmission projects have multiple sets of values, and they change over time. It's conceptually simple to allocate cost to the beneficiaries. But not only are the politics difficult, but also articulating exactly who the beneficiaries are is difficult, aside from the generator interconnection issue. So, just from our previous conversation, I do think it's important to find the policy drivers to get valuable transmission built in a cost effective way.

And, again, the consensus is that some of the components of Order 1000 have negatively impacted the way transmission is being planned, in that the thought is, "Oh, if it's locally cost assigned, then I don't have to be subject to competition." And I do fear that, whatever solution you come up with, there's always a reaction. If you do believe the competition brings some benefits, and you do believe that having more competitive projects is valuable, how do we actually get that done without this negative reaction? I think the first step is to have some robust cost transparency, because, right now, there are many projects being built that go over cost estimates…whether it's due to cost estimates that are not accurate, or too early, and the bandwidth is really high until you really know the project. But we don't have a tracking mechanism for the majority of the projects, so we don't actually know…Over time, we're getting better at the cost estimate. But I'd like this to get to a place where the cost estimate actually matters, and the cost proposals actually matter, and if that's coming through the competitive process, then the competitive process is driving some of this attention to the cost.

You did mention something about leaving off a lot of beneficial projects from this bottoms-up plan. I'm wondering if you can elaborate a little bit about that.

Questioner: Order 1000 requires that an interregional project has to meet the beneficiary test for both regions. There are reasons why that was done. Again, for bottoms-up planning, there were reasons why that was done. But that does give you a different answer than if it was top-down, where there's a larger benefit, but each region doesn't benefit. That's tough. That's a tough answer. FERC didn't give that answer, but that's what I was referring to when mentioned projects falling off the table.

Respondent 1: Of your five points, point one and point three, I think, are important to address. The point that were not looking at cross-regional projects well, and we basically cannot get any of those built--that's an issue. And I think your point about Order 1000's competition requirements being tied to regional cost allocation…I don't know what the lawyers think in the room, but it seems like there's no reason to necessarily tie those two things. So I'll just leave it at that.

Respondent 2: To the point about the local benefits. I think what we see today, at least in MISO, is that local is actually local. I think the risk we have for the future is, are there incentives to make things local? And that hasn't played out yet. And this generator interconnection, which is a cost causer, versus the beneficiary pays standard, is a huge barrier, both regionally and inter-regionally.

Respondent 3: I would just jump in here and just say that when Speaker 1 said, "Well, you know, the estimates should matter, and the actual proposal should matter," to get the estimates to matter, you don't need a competitive process. We can do that without having competition. In terms of getting the actual proposals to matter, I think that you need to have some caution there, because a race to the bottom isn't really what we want. We want the best cost effective project, not necessarily the cheapest one. There are ways to make projects cheaper that aren't desirable. And so, while no one is suggesting that that's the outcome we want, I do think we need to recognize that, particularly if we have entrants in the space who aren't looking to hold the assets for a long time--who are looking to come in, get the right, and then arbitrage, maybe aggregating more than one project, maybe just getting the rights to build it and then selling it for a premium, whatever it may be. And so I just think we need to recognize that there are some challenges associated with that. It's not just as simple as saying, "Well, if we could just get more efficient, everyone would just do great." I think that's great, but we also don't want to create an incentive to just build cheaper to meet some arbitrary number.

Respondent 4: I think, when the Brattle report comes out, that it's time to start a national discussion on how to improve Order 1000 and how to advance the ball for more competition. And I think it immediately brings up questions, in terms of, how do you do this at a regional level, or do you do it at a national level? But the record is clear, in our view, about the merits of competition, and about the merits of what these competitive windows have brought, and it's really time to start the national discussion on how to improve Order 1000, whether it's at a national level or region by region.

Respondent 5: I'll add something to that as well. As Respondent 3 said, estimates do matter. And we were somewhat surprised when we saw the Brattle presentation, as far as the estimate that supposedly the incumbent utility projects were coming in at 34% above their original estimates. So we did a study of our own projects – a sample of over 350 projects that went into service from 2013 to 2018. This was the class 4 level, so our cost estimating standard was +50% or -30%. Forty-four percent of those project final costs were over that preliminary cost estimate, but 56% of those project final costs were below that estimate. We had less than 10% of the projects that were outside of that class 4 band, and we didn't do any adjustments for scope changing of those projects. So, at the end of the day, our total performance for those projects was 0.7% under the preliminary cost estimate. So I would agree with Respondent 3 that estimates do matter. We feel like we're doing good estimates. Of course, we back-cast to see, when one is outside the band, what could we have done better to get it into the band? And so at least all I could say is, for AEP, our evidence doesn't support this 34% increase, and I don't know if any other utilities in the room want to speak, if they've had an opportunity to take a look at their data, but that is not what AEP's data is showing.

Question 5: In response to some of the questions about this cost-benefit analysis story, let me say that there seems to be some confusion – as I have described and others have described – as to the difference between *ex-ante* and *ex-post*. So, cost benefit analysis is *ex-ante*. You do it before the fact. You do it before you build the project. Then you say, this is what we think. Should we go out 40 years? Sure. Okay, you know, should we value all the things – the reliability bucket – and add it to the public policy benefit and add it to the…right, you aggregate all the benefits. So it's conceptually quite straightforward. And I don't know how to do that calculation without identifying the beneficiaries *ex-ante*, because that's how you do the cost-benefit analysis:

"Suppose we build this project, suppose we don't build this project," you know, we have two different things and have a distribution of costs and benefits and all those different things, and then we can identify who's benefiting, and so on. And then you allocate the cost associated with it *ex-ante*, not *ex-post*. It is not hard, conceptually. It's not perfect, and cost-benefit analysis is not perfect, but all the information is already there, if you're doing it.

I think part of the problem is that sometimes the answer to that problem is, "This isn't worth it," because the folks in Mississippi who were identified as the beneficiaries say, "We don't want it." Well, New York has an answer to that, not in their practice, but in their tariff, at least, which is a voting rule. And if you can't get a super majority (in their case, 80% in favor of it), you don't build it. And so that's deferring to the market, and the beneficiaries get to decide.

So if you take the premise that all transmission projects that we think are a good idea should be built, well, then you don't need to go and ask the beneficiaries, and you don't need to have that conversation, but if you take the premise that maybe (though I doubt it's true) Speaker 2 is wrong in her analysis, and actually the beneficiaries are right, then I would defer to the beneficiaries and not go forward. So if you put all those ingredients together: you have to do cost-benefit analysis, you have to do it *ex-ante*, you have to identify the beneficiaries *ex-ante*, you allocate the cost to the beneficiaries *ex-ante*, and then you let them have a say in whether or not to go forward, and if they say, no, then no is probably a pretty good answer. And if they say, yes, that's also probably a pretty good answer.

Respondent 1: I agree with everything you said about how you do the calculation, and it's conceptually easy and, in a lot of cases, it's even technically not a problem. The discussion of the voting makes me nervous, because there are a lot of reasons people are voting that actually have nothing to do with the benefits that are on that page. And that's the political problem, right, that I haven't quite figured out how to solve. And so, from the RTO perspective, if my objective is to kind of maximize value for the region, it's hard to square those things. I think that's where the challenge comes in for me. It doesn't mean we can't do it. I mean, procedurally, it would be possible. I struggle with whether it is in line with my mission, but it's worth thinking about.

Questioner: Could I just respond to that quickly? I think that was an enormously helpful answer. And if we could frame the conversation, going forward, to address that problem and have people talk about it candidly, I think we could make real progress in this process.

Respondent 2: I would just add that, eight times out of 10, decisions on transmission and what's getting built and not getting built are about generation. They have nothing to do with the value of the transmission itself. So, I mean, you have to start from that premise and understand that a large percent of it is stakeholders or market participants, and they're looking at this from the perspective of who's a winner and who's a loser, and they're not looking at it from the customer value point of view. And, you know, FERC has this sort of robust regional planning, and that's why we have RTOs to create some sort of layer of independence on top of that, but, you know, the reality is that that's kind of how it goes [LAUGHTER].

And so it's not just that it's a little difficult to sell people on the benefit. It's also difficult to move the status quo because, inevitably, that leads to, "Well, you can get more wind in now, so we don't need that higher-cost base load." And I don't think I need to go dot-dot-dot to tell you then what happens. Well, now we've got to come up with a plan to save all the base-load generation – no offense to anyone in the room [LAUGHTER]. So, you know, I do think that there's a complexity there, and it is political, if you want to call it that, but it is also economic.

Question 6: I've been hearing a lot of discussion about what would seem to me to be two issues, and I just wanted to get the panel's view on how related they are. On the one hand, we've obviously talked a lot about competition and the extent to which projects put out to procurement in some form can lower costs. We've also heard a lot about establishing agreement within a region with many stakeholders to engage in a project that will then allow the developer to get cost recovery, dealing with the cost allocation issue. I'm kind of wondering about the relationship between these two. That is, does competition help or harm that forward-going process? And, Speaker 2, at some point in your early remarks, you said something that alluded to how this is a political process, and I think you alluded to idea that competition may or may not help, but I'm just interested in the panel's view on this, because my economic mind sees these as very separable. That is, we identify what the projects are, and I'm thinking particularly about regional policy projects, where we really have to get a complex stakeholder mix across both states and different, parts of the sector, and that's challenging, and MISO succeeded with that with the MVP project. New England has kind of failed and not been able to get around the different state views. And so I'm just trying to understand whether or not people think there's a relationship between these two, or whether or not we can really sever them and deal with them separately?

Respondent 1: Well, I think the first place to just start in that discussion is that you look at not only what Order 1000 said, but you also look at what the courts said. And the courts very strongly upheld Order 1000 across the country -- whether it was the DC circuit, the 7th circuit, the 5th circuit – they upheld the notion of Order 1000 and competition. And the premise in Order 1000 was always that there is a linkage between the ability to use the regional cost allocation framework and competition. And Order 1000…clearly, it's for more cost-effective transmission to be built, but the foundation of it was that, when there's regional cost allocation, there needs to be competitive pressures. And regional cost allocation under Order 1000 is, essentially, when two or more utilities, or their customers in two different transmission zones, are paying for the transmission. And so that's the legal foundation for Order 1000, and that's what the courts upheld. And so this idea that, "Oh, let's de-link it," that is certainly a possibility. It could be built upon, and you could expand competition to the local zones as well, for sure, but the foundation of Order 1000 is that competitive pressures come in when two or more transmission zones are paying for a line. And it's not tied to a particular type of project. You can't say, "Oh, well, we won't have competition for public policy projects if they're regionally cost allocated." Order 1000 said, if there's regional cost allocation going on for any type of project, then there needs to be competitive pressures from it. And then FERC also said there were certain types of exemptions, such as if it's an upgrade or there's a state regulation.

Question 7: Two things. First, a real quick comment. To the person arguing for *ex ante* cost allocation, people have tried to do this [LAUGHTER]. They've tried to do it your way, and, if you sat through the years – literally years or decades – of people trying to squirm away from that to get a favored position, it's very, very difficult. I mean, there are certain types of meetings I don't even consider attending any more, because of the frustration of that period.

But I wanted to follow up on what another questioner said, because I think it points out the need for a paradigm shift. Generator deliverability takes a big bite out of what might be deemed to be part of the upgrade picture, and that is costs allocated generators. And PJM has a different paradigm for that. You buy it as a generator, you own it, in the sense of property rights. There are no refunds. It works differently in PJM than other regions. They also have the load deliverability CTEL (capacity emergency transfer limit) structure, which isn't necessarily nonregional or zonal only, but a lot of it is, and so that takes another big bite out of it. Then you have the supplemental project bite, which we argue about enormously - it's like eight-to-one or nine-to-one of expenditures which are exempted are in supplemental projects. And so, when you look at that, I don't know if you get to 2%. You get a very, very small pie.

And then I couple that in my head with the fact that, in the abstract, there is a competitive vendor process here, but the group of vendors who actually do the work, they're the same ones that almost all of the companies use. I don't know if it's one-for-one, but it's a reasonable universe that is predictable, and that's where there is some competitive pressure.

And then we've learned some other lessons along the way about excluding incumbents and PURPA. All the early fights were about the exclusion of incumbents or limits on incumbents. So that brings me to a paradigm where you bid ROE (and I think you can lock it in) but what you do is you give some fixed share to the incumbents, and the incumbents manage a process and then they bid out equity. To me, that instantly yields a world in which we see a whole bunch of people who are excluded financially from participating that would see relatively low-risk environments and a huge pool of capital. Think about insurance funds or, you know, CalPERS is a good example of a historically super low-cost investor in equity on the generation side. And this needs a fix to Order 1000, but what it does is it recognizes the reality of the pool being small and maybe opens the pool by doing that, and it gets competition so that, for example, LS may want to do something, and they can compete on equity. The only downside is it tends to be a little stiff on innovation, because you're sort of going the traditional route. But the key points are keeping it inclusive of the incumbents and recognizing that you can do it on a project basis. That's how PJM funds things. Remove the reason to hide projects in supplemental, because they'd automatically come up for bid, and put the competition where it's transparent, which is in the equity pools, and find ways to lock them in while keeping the incumbents in with an incentive. You know, let them manage the process. I don't even really care about that. I'd just like to see the money competed out on the equity side, which is where I think the huge amount of savings are there, and they're there without fighting in the "who pays" world. Everything just goes on as it was. I'd sort of just like people to think about that. Any comments?

Respondent 1: Well, I would add that, certainly, if you look at what's happened in PJM in the last year and the discussions that have been going on in the stakeholder process relating to cost containment, the members voted for PJM to be putting together templates on looking at cost caps, ROE, and capital structure in the bidding process and basically limiting how they look at cost containment to those three main items. And my company thinks that's going to advance the ball significantly. There are other regions of the country that are going even further. But looking at the pool of construction costs, ROE, and capital structure, and competing on those items, is going to provide consumer benefits. There's no question about it, from my company's standpoint. And that's advancing it. And that's better than just saying, "Hey, you know, right now, look at our cost estimates versus construction cost caps." Well, if you start bringing in the world of capital structure and ROE into the competitive process, that also has the potential to bring consumer benefits.

Respondent 2: I would say first, contractually, you might be able to get at making the ROE that you win on the bid durable, but, at least in my conversations with FERC staff, the issue that was raised is that it's not actually a competitive market, and, until there's a competitive market finding, you can't allow that to set the cost. So I'm just putting that out there. I don't know how to fix it. Let me know.

Questioner: I agree. I mean I'm looking at a world where you get the project, and then you bid the equity.

Respondent 2: Right. And then, you know, if we want to get into a conversation about bidding equity and ROE, which are traditionally regulated, then we have to look at the idea that those prices can go above whatever the regulated rate is. So someone can bid 80/20, 80% equity. And I think that when we look at some of the markets we've see, for example, capacity markets, or when we look at the original wholesale markets, at least before the price of gas dropped and renewables became a lower price point, we saw movement up, not necessarily down. And I think that just assuming that, well, everyone's just going to race to the bottom and have the lowest number – maybe. Maybe there are going to be projects people don't really want to build, because they're not very desirable and you're not going to make a lot of money, and so people will bid higher numbers. So I do –

Questioner: That's okay though. We want to look..

Respondent 2: That's my point, though. I think what we have right now is a situation where you have a regulated rate you can't go above, and you're being asked to bid lower, and that's not really symmetrical. So that's my point.

Questioner: You don't have to bid lower, and there's no reason that the equity bids aren't compensatory with those expectations. I mean, I've watched project finance now for – actually the first one I saw was in 1976, 1977, pre-PURPA – and there's competition in funding, and people are willing to take risks, and they're willing to lock in. I don't want to put any of the attorneys here on the spot, but they can weigh in on how well you can do that within a regulated environment. It becomes a tariff. If you structure the contract right, it becomes subject to public industry standard. It's not flimsy. It's not a case where you can go in and say, "I don't like the number anymore." You have something that is durable.

Respondent 2: Well, I think the durability is a huge issue, because, of course, we can't bind future commissions or future RTO policies. And so, 40 years from now, who's going to be there to say, "Yeah, we know we agreed to this, but we've changed our mind." I don't know. If it's contractual and somehow you can make that sacrosanct, then maybe it works, but my experience has been that things change and so, you know…

Questioner: Our sales agreements stand for 20 years, and where they have satisfied the regulatory criteria, they have stood without intervention, not coming back in for "just and reasonable" consideration.

Respondent 2: I guess I would just say that I think that if we're going to have a competitive marketplace to do this, then it needs to be completely competitive. It can't only be kind of competitive on the downside for the developer. That's all.

Respondent 3: I just want to add to your list, though. I think, at least through the sponsorship model competition, we do see quite a bit of innovative solutions. Talking to different developers on different projects, you see that they come up with different ideas. It's not just technological – that, too – but also just finding the innovative solutions to a problem, and they do come to it with different offers.

Questioner: I admit that what I'm suggesting sacrifices some of that. It's just, you know, you get a perspective after banging your head against the wall for 20 years, and maybe you give up a little of that and make progress elsewhere, because we are so slow in the trade-off. Like you said, you know, you can get a generator going – it's still not overnight, but it's very, very, very quick, in comparison to transmission.

Question 8: Very interesting discussion. I'm leaving this discussion with the idea that transparency and competition could help to lower transmission costs overall. I've heard some pushback on competition, but I haven't heard any pushback on the idea of increasing transparency, and I'm wondering, Speaker 1, if you've gotten any positive feedback with respect to your transparency conclusion. And I was curious to know who commissioned your study, if it was commissioned. And then, Speaker 3, you mentioned that ITC is coming out with a paper of some sort, and I just didn't have in my notes exactly what that would cover.

Respondent 1: The paper is commissioned by LS Power, but the work is independently conducted. But you're absolutely right. I actually think it's very difficult to increase competition without having transparency first. And the way, in my mind, this works is that it's very challenging if you don't really know what all the projects are. We see some of the projects through the planning process, but we don't see all of them. As the questioner mentioned, you can, you know, sort of remove the incentive to hide projects. It's a little extreme, but there is a reaction to competition, and utilities do have a protectionist reaction to this, but, if we don't see the projects, if the information is not publicly available, then we don't even have a way to say, "Wait, you know, here are five different small projects you could do instead, but this is really solving a regional issue that really should be subject to competition." So you can identify specific projects and force them to be subject to competition, but I think it's very difficult to have a long-term solution without the transparency.

And then you asked the question, "Well, who's going to say no to transparency?" It's hard to push back to say, "Oh yeah, we really shouldn't have a national database and tracking mechanism." I mean we're living in the world of data, and we don't have enough information on the investments, and it's multi-billion dollars of investments over time. So it's hard for me to imagine why people who care about policy would say no to transparency, but the reality is, there are people who are pushing back on transparency and say, "Well, we don't really need it…it's local…let the utility do their jobs…it gets in the way," but I have a hard time imagining a long-term solution to drive competition without the former transparency question.

Respondent 2: I don't think most people would oppose transparency. Maybe I'd be surprised, but I would just say that maybe we have a difference of opinion in terms of, at least for current projects, how much transparency there is. On the competitive project side, I don't think there's a lot of transparency, because a lot of stuff is redacted. We don't have any idea, necessarily, all the time, who gets picked and why. There's just a lot there that isn't really as transparent maybe as it needs to be. But on current projects, like I said, you can find out anything ITC does through our protocols and, you know, all our project stuff is in MISO, and so it's pretty transparent. In terms of the report, it's not an ITC report, it's actually a collection of entities. We don't have final sign off, so I don't want to list all the names, but it will be out relatively soon.

Respondent 3: And I would add to that AEP, as well. I believe we're fairly transparent in our process; certainly, on the back end in our formulas, and everything which puts rate into service. There are all kinds of discovery processes that we follow. So we're open to a reasonable level of transparency within the confines of protecting competitively sensitive information and things like that. But it's a legitimate business interest.

Respondent 4: And I would respond on the transparency question by saying, we believe that. in the competitive realm versus the noncompetitive realm, there is a world of difference on the transparency. For instance, if you go out and you look at the competitive bid process in MISO or SPP or CAISO, whenever these Order 1000 projects have gone through the competitive process, there's typically a very robust selection report that is associated and tied to each of these competitive projects in terms of who bid, in terms of what the bids were, in terms of how they were structured, and there's a lot of transparency. But even more importantly, what's different about these competitively bid projects versus noncompetitively bid projects is, once they are awarded to whoever is deemed as the most cost-effective project, the developer signs a developer agreement with the RTO, and then, essentially, they have extensive reporting requirements that come with the development associated with that particular project. It's called a designated entity agreement or a developer agreement in most of the regions. And, basically, there are extensive milestones that are part of that developer agreement. There are extensive tracking and quarterly reporting requirements, and it's far more significant than what you have in the noncompetitive side of it. In addition, there are the credit support requirements that come with it as well. And I think one thing that isn't talked about that much in the realm of the Order 1000 world is that these designated entity agreements that the winning bidders are signing are basically producing a lot more information on what's going on on a quarterly basis for each of these projects, and it is more extensive than the noncompetitive world; especially compared to the world you see on the supplemental side.

Questioner: Is that information actually available on the OASIS, or how do people see it?

Respondent 4: It really varies by RTO in terms of where it's available.

Question 9: I think part of the premise in one of Speaker 1's arguments is that there are cost overruns, and this tells us that there might be room for help through competition, but I'd like to know if you've done any work to explain what the most common factors are that cause the cost overruns? I know that AEP, apparently, has done after-the-fact studies on why they had cost overruns, and I see that your list of risk factors impacting all projects, but part of the reason I ask whether or not you've ranked the reasons for the overruns is that I want to test whether you would be any more or less successful in evading these risks if you had a nonincumbent versus an incumbent doing them. For instance, on environmental issues, it's not clear to me that one side's going to be more advantaged than another one. On cost of capital, one side probably has a better position than the other one, just based on size. On right-of-way, one side probably has a clear advantage over the other one. So, is there a ranking? Where would I go to get that information? And has there been any comparative analysis about whether these are the main causes for cost overruns? Would you face more or less risk going the nonincumbent or the incumbent route in overcoming those risks?

Respondent 1: Oh, that's a really good question. For this study, we did not go into every project and understand what the causes are - if that information is even available. We have done some other studies in the past that look at the type of drivers of cost increases. You know, the word "overruns" suggests that they somehow did it poorly. Some of the cost increases are very legitimate. I think we acknowledged that, even with cost containment in the competitively selected projects, there could be cost escalations, including things like inflation on material, certainly routing changes that's due to siting reasons and permitting reasons; however, I think what we're trying to say is that, based on the data that's available and that we scrutinized, there is sufficient head room for the competitively selected projects to even have some cost escalations and still produce costs that are a lot less than what we have seen in the past. Now, one can say, "Well, our cost estimates are better, we are improving our cost estimates and so, you know, in the future even the noncompetitively selected projects will be less..."

Questioner: What I'm trying to get at is, what would those reasons be? Would a nonincumbent be smarter than an incumbent about route selection, or less exposed to environmental litigation about what the route would be? It doesn't seem like that's right. Would a nonincumbent be more exposed or less exposed to fluctuations in the price of cement or steel to build something? That, again, doesn't seem like something that they are more or less likely to get a better deal from. So what is it? Is it that they're leaner? So, do we expect to see the benefits on the return on equity that they're looking for? Is that – is that part of it?

Respondent 1: I think it's back to the transparency question. Even though, you know, you may say, "Oh, well, we looked back to our projects, and they're all on budget," when we scrub the data, we encounter a lot of information saying things like, "Oh, if you just went to that particular ISO's meeting on that date, there was a reporting on certain projects in a bundle, and you will find that there is an update on the cost estimate." Okay, if, anecdotally, somebody tells us. But there is no consistent standard way of tracking where the project estimates were – understanding there's a range and, you know, you get smarter and sharper about it and then where it ended up. So not all projects are like this, but for many of the projects, there's no monitoring. So I think it's really on the incentive side that it's different. I'm not saying that the contractors are different, and some contractors are better than other contractors, or that incumbents are doing it differently or worse, but I do think incentives matter. And I think, so far, we haven't had enough monitoring of the process and the cost and the spending, and I think what Speaker 4 was saying is that the competitive process puts more pressure on….one, you do do a much better due diligence up front, so that you know what you're getting into and what you're locking yourself into, and then, two, to keep the cost down, and we've watched developers that have won through the competitive process, and they're very, very careful about every dollar they spend, because they have committed to a particular cost. And I think that incentive matters.

Respondent 2: I would just say that, if you look in your folder, my presentation is in there. The information on cost escalators, by and large, came from an SPP report that's a little bit dated. So I don't think there's anything intrinsically different between an incumbent and a nonincumbent on those factors affecting them. I do think that what we're basically saying is, you can either regulate to try to keep people to cost estimates, or you can use competition as a surrogate for the regulation. And the question is, which one is more effective? Because I don't think you have to have a whole competitive process to say that you have to stay within the bandwidth of your cost estimate. You could do that. I think the transparency thing is really interesting, because I think we were talking past each other a little bit. I think all the information is out there; I think it's not easily accessible, and so maybe the issue is that we just have to find a way to make it easier for people to find and aggregate it in some fashion. Because I do think that if you're involved in this stuff day in and day out, you see this stuff. Right? But if you're just an average person who wants to know, "Well, what happened with that project?" it's very difficult to locate. So I see your point on that. And I guess the only other thing I would say is that I do think that there's a fundamental question here about, are we really trying to get cost discipline on project costs and construction and get at the unfortunate incentive of gold-plating, and that's how we make money, or are we really trying to lower ROE and lower cost of equity and really get at some of the fundamentals of the regulatory compact? Because I think we're trading apples and oranges here. We're not really talking to what we're doing. If what we're trying to do is drive down ROE, well, that's a very different conversation than if we are trying to make sure that we're building the project the most effective way we can.

Session Two.
Gas and Electric Coordination: Evolution or Revolution?

The resilience discussion raises reliability questions about vulnerabilities in power supplies due to interruptions or shortages in natural gas. Economic efficiency dictates that short-term trading of gas supply and pipeline capacity to help meet power demands might benefit from more than the invisible hand. Market power in one market has been argued as affecting returns in the other. The benefits of organized electricity markets in improving market operations have been recognized. Would similar reforms in natural gas be helpful? Do reconsiderations of resilience need imply greater coordination between the markets? How might economic efficiency be improved through an explicit coordination of dispatch? Given the different physical scheduling and trading practices in natural gas and power, how difficult would it be to formalize coordination? How would reforms affect current trading practices? Is the invisible hand already working well enough? Are market operations and market monitoring reforms needed? Or should the oversight regulators leave well enough alone?

Speaker 1.
Thank you very much, Moderator. Thank you, Doctor Hogan, and thank to the Harvard Electricity Policy Group for having my organization as a participant here. And it's also an honor to be with these panelists. My organization fundamentally believes that well-designed markets that efficiently allocate capital provide benefits to rate payers, to shareholders, and to the environment. And we understand the critical role of gas in terms of decarbonization and in our energy system, and so we've been working on this issue. I've been working on gas, electric coordination for at least seven years. And, actually, many of the core messages that I'm going to present today are messages that I've been presenting for most of that time.

So, here's a summary of my presentation. FERC's market evolution, starting back in the early 1990's, towards competition and unbundling transportation services has been extremely successful, but requires updating. There are some vestigial design elements that predate what is now the largest user of the gas system, which is power generation, and have the effect of preventing contracting between power generators, the largest user of the pipeline system, and the pipelines upon which they rely to get fuel and generate energy. In addition, those impediments to contracting also are obstacles to scarcity pricing.

One of my themes here (and I'm going to basically credit Dr. Hogan for this) is that, as we reviewed the extensive academic material on scarcity pricing in the electric markets and sought to do the same in the gas markets, we found that there's a bit of a dearth of academic material on the gas markets as to the impacts and the need for effective accurate scarcity pricing. So, lastly, (and this is the main point of my presentation) market rules which facilitate contracting between generators and pipelines and improve scarcity pricing for power generation takes will stimulate investment and innovation, because of course pipelines are not the only answer to eliminating scarcity and channeling investment.

So, just a little bit of background here. This picture shows what some of the effects of FERC Order 636 and its progeny were. If you recall, in 1992, FERC issued Order 636, which fully unbundled transportation rates, separated them from supply, took the pipelines out of the merchant supply business, and it established the firm and interruptible market paradigm that still exists today. And so, what this chart shows is how that firm and interruptible paradigm is translated, from a rate design standpoint. The concept is called "Straight Fixed Variable" rates. Essentially, all of the fixed costs associated with pipeline capacity are built into a reservation fee, and all of the marginal costs are built into a commodity cost, or a commodity fee. The point here is that pipeline shippers generally pay for pipeline capacity through reservation charges that apply every hour of the day, 8,760 hours a year, and these are "take or pay" contracts. Whether they use the capacity or not, they pay those reservation charges, and, as you can see, those reservation charges make up the lion's share of the cost of pipelines. The commodity cost, or the usage cost, is what's paid for by interruptible customers. And that's what merchant generators largely rely on. What they rely on is interruptible capacity, where they can bid those marginal costs, which are rather small, into their hourly offers in the electric markets and hope to recoup them, whereas it is not cost effective for them to seek to sign long-term contracts for capacity and bid those into the markets. And, of course, power generation is now the largest user of the natural gas system, and it's growing. We're in about a 90 to 100 Bcf per day natural gas market. Power generation is somewhere in the area of 40 percent of that, at about 42 Bcf per day. And the reason that power generators do not sign long-term, firm contracts for capacity is because not only is it a challenge for them to recoup those costs, but also they cannot include those sunk costs, those capacity payment costs, into their hourly offers.

But there's also a pipeline cost and use equation. In other words, if you're paying for pipelines, but are only operating them at a 50 percent capacity factor, you're still paying for that capacity. So, this was an analysis that a consultant for us undertook, and it shows, basically, that a gas-fired power plant, operating 16 hours per day, five days per week, with two weeks down time a year, essentially amounts to a 46 percent capacity factor for a gas pipeline, and their actual transportation costs amount to $24 a megawatt hour of fixed costs. So, obviously, the more a plant runs, the lower that cost is going to be, but as we get into a more renewable paradigm, we're going to see these plants running less, but providing that extremely valuable peaking service.

The natural gas market is premised on price signals as the impetus for capacity investment. I would imagine most people here are familiar with the concept of basis differential, but the basis differential is just actually the difference in price between any two pricing points on the system. And the idea is that if that differential is so great that it's more than the cost of adding new capacity and signing a long-term contract, then some entity would sign a long-term contract to eliminate that basis differential. But what we're seeing in the marketplace is that basis differentials are decreasing, particularly as the system gets built out. What we have is a system that is premised on the value of point-to-point capacity. And that's what a basis differential essentially triggers. It shows the value of point-to-point capacity. But, as we build out the system, and as we have now four to five different production basins geographically dispersed around the country, the value of point-to-point capacity shrinks. And shippers have multiple choices from which they can get supply, and pipelines from which they can contract to get supply.

All of this means that the paradigm that is the impetus for the development of pipeline capacity is changing. A classic example of that is Transco (the Transcontinental Pipeline), which is the blue line that runs from the Gulf Coast all the way up into Pennsylvania and New Jersey. Transco's now bi-directional. So, what's the value of point-to-point capacity on a bi-directional line? I would respectfully suggest that Transco is probably the most important storage vessel that we have in this country when it comes to natural gas. Six billion cubic feet a day, which goes in any different direction. But they're not getting compensated for those services. They're not get compensated for providing variable flows to generators, moving gas from here or from there or storing it. They're getting compensated for one thing. Point-to-point capacity. From my point of view, that means that they're leaving money on the table. And as we see a more reticulated system, we see the ability of the natural gas pipeline system, broadly speaking, to provide enhanced delivery services and to provide enhanced flexibility to meet the needs of a peakier and more dynamic electricity system. But fundamental to at least our premise, in terms of the market design refinements that we're supporting, are that those just in time deliverability services are unpriced in the market. We still have a marketplace that is premised on just the daily value of capacity.

Here's an example of a misalignment. This is an illustrative slide. We undertook very detailed analysis, over three years, using EPA, ISO New England, and Platts data relating to the interaction between the gas markets and the electric markets in New England in particular. And the blue horizontal line represents the daily index price for gas. That's the published price upon which transactions are generally based. The green line essentially represents the revenue per million BTU that a power generator garners from combusting that gas and participating in the electric market. So, there are a couple of conclusions that come out of this. First of all, if a generator is paying the natural gas index price, it's paying too much for part of the day and it's paying too little for part of the day. The gas is worth more or less than its paying. Now, in reality, power plants don't generally, or often they don't, pay that daily index price in the spot market, but there's been a long history whereby market monitors on the electric side would mitigate hourly offers from generators based on the standard created by the natural gas index price. Now, more recently, some of the RTO's have started providing more flexibility to generators in terms of how they price, and how they offer gas. But, historically (and there's been a multitude of FERC cases), generators were mitigated based on what the daily index price was, notwithstanding the fact that that's not what they were paying to obtain fuel. Likewise, the natural gas market presumes ratable flow. And ratable flow means, essentially, that from the time that a shipper nominates and starts taking gas, they take roughly the same amount of gas every hour of the day. But, in fact, virtually no generator operates over the course of a full day using ratable flow, and the last time we checked, somewhere around 10 percent of the transactions in the gas system used the provisions of tariffs that allowed for non-ratable takes. In other words, 90 percent assumed ratable flow, but more than 60 percent of takes were non-ratable, across the whole system. And for generators, that's essentially 90 plus percent of takes, and I've heard that from several of the pipeline operators. So, the fact is that there is not a means to price or value those non-ratable takes, and in fact what's happening in the marketplace is the pipelines are providing a service that has value to the power generators, without it being priced. And I'm a lawyer, but all you economists know the answer to this question. What is the extent of demand for a valuable service that has no costs? It's infinite. Right?

The other assessment that we undertook was just comparing the generators' hourly gas spend with what the compensation was in the electric market. And this is a pretty loose conclusion. I wouldn't say this is that rigorous, but our general conclusion is that if there were structures for the generators to create an efficient and transparent market for hourly flows, or sub-day, sub-hourly flows, that they would earn sufficient revenues to cover those costs.

Because we're EDF, I've learned that it's better for me to express the perspectives of market participants that invest money and risk capital than environmental advocates. So, I just thought I would put up a couple of quotes from some of the market participants. API, essentially, has agreed that in terms of seeking "energy pricing reflective of real-time market fundamentals" and that "Stale day-ahead energy pricing produces inefficient rates." PJM has constantly been talking about this, most recently in the resiliency docket. The Desert Southwest Pipeline Stakeholders have also talked about the need to obtain and to price natural gas that's needed to backstop the intermittent nature of renewables. So here's my rhetorical question. If reliable operation of the electric system depends on variable hourly delivery service, shouldn't the value of that service be reflected in the markets?

I thought I would provide an example of how it is that price formation is being diminished and, in particular, scarcity price formation is being diminished. I know nobody can read that, but that's an operational flow order that was put out by the Algonquin Pipeline in New England during the bomb cyclone of 2017, that very cold weather event. And essentially what they say is that non-ratable takes on their system will have adverse impacts, and they urge their interconnected point operators to take ratably and not non-ratably. So, play that out to the extreme. Essentially what are they saying to the power generators that are their point operators that are taking flows? That the way that we can provide you gas doesn't work for the way you use gas. Right? But here's the interesting comment. The way that the RTOs are dealing with this challenge is that they're exchanging information with the pipelines, and they're basically dispatching generation based on the capabilities of the pipeline to provide fuel. They might be deploying oil units. In other words, supply and demand in the gas pipeline side, as between generators and pipelines, is being moderated, not by price and not by market, but by exchange of information. And that is not a cost effective way, that is not an efficient way, to send a price signal or to eliminate scarcity.

So, this gets into some of what our recommendations and our problem statement have been, which is that the pricing disconnect prevents an expression of the value of investment or innovation in the next needed increment of capacity to overcome a constraint, in order to provide gas for a generator. And, Dr. Hogan, this is very much akin to the work you've done in ERCOT, where you've pointed out that even slight impediments to scarcity pricing have significant implications to market participants' willingness to risk capital. And I would respectfully suggest that some of what the RTO's are doing, through sort of out-of-market resource allocation to resolve fuel supply challenges, actually impairs price formation and impairs those investment signals. And, of course, I understand there is a reliability aspect to this, but, nonetheless, we're not going to get the investment we need. We're not going to get the kind of price formation we need. And, ultimately, we're not going to get the resources, whether that's demand response, or storage, or LNG storage, or compression on a pipeline system, or more pipeline capacity, without having those kinds of efficiently and transparently created price signals.

So, I just want to conclude with what EDF proposed as a solution here. We proposed what we call Shaped Flow Contracting. Let me just step back for a second. FERC Order 809, which was the Gas Electric Coordination Order of 2014, directed NAESB to explore options for faster, more flexible scheduling. I'm on the Board and Executive Committee of NAESB. We proposed a standard for "mutual agreement" contracting that would allow a shipper and a generator to nominate and schedule quantities of gas that vary by hour over the course of the gas day. Now, think about this for a second. There currently is not a standardized means for a shipper to nominate and schedule quantities of gas that vary by hour over the course of the gas day. The same service that the largest user of the pipeline system relies on, there isn't a standard way for them to even request it. So, our thinking was that if we could get a standard like that created, we could start price formation around the hourly value of that fuel and the hourly value of that supply in a more efficient way than we do it right now.

So, these are our recommendations. There's a need to standardize terms for generators and pipelines to contract. When your largest user's not contracting with the pipelines upon which it depends, you don't have a resilient system. And so, we proposed adopting a shaped flow protocol to germinate that just-in-time deliverability market price. The flip side to this is to allow generators, in their hourly offers on the RTO side, to have the flexibility to include those prices in their bids, which many of the RTOs have been moving forward with efforts to enhance. We also want to invite pipelines to charge for those shaped flow transactions and earn incentive returns under FERC's incentive policy, which has seldom been used. And, on a case-by-case basis, it would be appropriate at times to look at how individual pipelines are serving these non-ratable flows. There are certainly people at FERC who think that the way it's being done now implies discrimination, but that's for another day. So, that's my presentation.

Moderator: Before we move on Speaker 2, maybe we should take a couple quick clarifying questions. Yes?

Clarifying Question 1: I participated extensively in the NAESB electric gas coordination. And as I recall, there are actually a couple of pipelines that do permit non-ratable nominations. And as it was explained during the process, it seemed that it wasn't as much a tariff issue as a technical issue for some of the pipelines. It involved re-metering, or whatever. Your statement seems to be implying that it's a tariff design issue, whereas I believe, based on those discussions, that some of the gas pipelines are in fact already doing it, and the pushback from the others was that it was an operational, physical challenge. Could you talk about that a little bit? I don't know if you're making that distinction.

Speaker 1: Thank you for pointing that out. Under Order 636, the Commission essentially required the pipelines to provide to their legacy customers "no notice" rates, which essentially end up being non-ratable flow rates. So, yes, almost all pipelines are providing non-ratable flow rates to their legacy customers. The problem is that interruptible and secondary firm customers have no entitlement to those services, and they're not priced. So, I can't speak to the technical issues. I can tell you, since you raised it, that at NAESB, every single pipeline, every single RTO, every single supplier, every single end user voted in favor of our proposal, but it didn't pass.

Questioner: How did it not pass?

Speaker 1: There was a segment block.

Clarifying Question 2: A quick question on your shaped flow protocol. Is this meant to be sort of free form, so that you could actually have any kind of shape you'd like under the proposal, or is it more, a case of, well, there's the flat rate, and then there's one standard shaped rate?

Speaker 1: It's meant to allow nomination that varies quantity by hour over the course of the day, and the proposition is that generators know their business and they know the marketplace well enough that they would be able to formulate that shaped flow nomination during the nomination cycle, and presumably that would then help create a pricing structure around…

Questioner: So it could be just a free form, and then the proposal doesn't include any sort of penalties or new pricing structure around not making your schedule?

Speaker 1: No, it does not. It's purely by mutual agreement as between a pipeline and a shipper.

Clarifying Question 3: Just clarify for me...implied in this is the gas day, and then intra-day for that product?

Speaker 1: Yes.

Questioner: OK. I'll think about how that works. Doesn't that create a commodity risk that makes the shaped forecast sort of a feedback loop in there, because of the two times flips?

Speaker 1: I agree with that, and, in fact, we know that any time someone takes non-ratably, they're either leaning on the pipelines' park and loan service, or they're leaning on someone else's ratable capacity.

Questioner: I understand. I'm just saying that this would be a dependent property that goes into the mismatch of the time steps, as well for a day ahead.

Speaker 1: That's true.

Questioner: So, whenever you were saying this, you're implicitly acknowledging the two days.

Speaker 1: Yes.

Clarifying Question 4: I have one clarifying question. The operational flow order itself, it sounds like you're saying that's an ineffective way of managing scarcity. I just wanted to get a little bit of clarify on that.

Speaker 1: So, the operational flow order (OFO) is not an ineffective way of managing scarcity. It's the way that the OFO is reflected in the marketplace that essentially becomes ineffective. Because then you end up seeing sort of an out-of-market incursion in order to make selections based on those communications between the pipeline and the RTO about who should be dispatched, who can get gas, who they have sufficient pressure to provide gas to…and that's what I see as an out-of-market incursion.

Clarifying Question 5: Don't you think that this is being done by marketers? The generators hire them, and then the marketers take and give the generators what they need, and then they market that gas--so that, in fact, it's being done, but maybe not on as transparent a basis as you would like?

Speaker 1: Yes, I mean, on a daily basis there are thousands of transactions where marketers are taking the ratable flow rates, the capacity rights of a shipper, and divvying those up into non-ratable chunks for generators and others. We just don't know what the spot market price or values of those are.

Speaker 2.

Good afternoon, everyone. It's nice to be here again. This is definitely one of my favorite conferences, because you always get good, engaged participation and informed questions. So, I look forward to the discussion.

The reason I think I'm on this panel is because New England has long been the poster child for gas-electric coordination problems. It's unfortunate, but that's how it is. And those issues go back to, really, the winter of 2004, when we had a severe cold snap, and gas generators were calling our control rooms saying, "I can't get gas. I can't come online." And our control room was…they were tearing their collective hair out. And that lives with us until today. Honestly, we're still trying to sort out the issues surrounding that, and so what I'd like to do today is give you sort of a brief taxonomy of why we had that problem, the things we've done since then, where we are today, and, probably most interestingly, where we anticipate going forward to, you know, I'm not going to be so bold as to claim, we will put an end to all of our gas issues, but to what we hope will be a major step towards helping resolve those issues in the future.

So, why did we have problems, starting in 2004, with lack of gas supply in New England? There are a number of issues. We don't (obviously) have, in New England, any local gas supply. We also don't really have any natural storage facilities, so we only have very expensive storage facilities. We're at the end of the pipe, which is problematic. If you look at PJM or MISO or ERCOT, they have a much denser network of pipes that have bidirectional flows. Ours are pretty much one way only, and are limited by what we can get through New York, as well. We also have problems, because New England is not an easy place to build infrastructure. It's not easy to build infrastructure, because it's population dense, and people don't want to see new infrastructure. It's also true that, especially in the last half dozen years, people especially don't want to see infrastructure that they believe will contribute to continued C02 emissions. So, regardless of how you feel about that, that's the reality in New England, and it matters in trying to get things built. Remarkably so.

And then we also have issues with low-price gas. It's creating this problem, because it's displacing oil and coal units that are retiring. Most of our coal is now gone. Our oil seems to be on the way out. So, we are becoming increasingly dependent on gas, due to its inexpensive nature.

And then, finally, there are information problems. Speaker 1 hit on some of these, but it's been pretty clear, when we look at what has happened over the last 15 years, especially 10 years ago and more, that the lack of understanding of the gas industry by the ISO and the lack of information sharing and situational awareness have been problematic.

So, that's sort of a list of some of the causes of the problems that we've seen. What have we done about that? We've done a lot of things--so many that I can guarantee that this list is not going to be complete. But the main things that we have done are, first, coordinate much better with the gas side. It was a long and painful set of conversations to get us to where we are today. But we think we're in a pretty good spot, in terms of getting much more information from the gas dispatchers in Houston. We download our own information. We run our own models, modeling the gas system, modeling which generators have gas. I will say, it's far more than our operators ever thought they would have to do, and much more than they would like to do, in terms of monitoring the gas system, but they feel that it's necessary to do that, so that they are aware of the gas situation in New England and the gas situation that their generators face. We've instituted hourly offers, which I'm happy to say have worked quite well--so much so that even our operators grudgingly admit that it's made a big difference in how generators interact with us and with the gas pipelines. That is, now that generators can update their prices every hour, they are much more willing to go out and buy expensive spot gas when we need it. In retrospect, it's clearly pretty basic, but it made a huge difference, and it's really transformed a lot of our relationships with our generators. We've done other things, like improve our scarcity pricing. That is, our scarcity prices are now higher than they used to be, so there's a greater profit incentive for generators to get fuel when we need it. We've done things like improve peaker pricing, and institute pay for performance in the capacity market, and we've done band aids, like winter programs that have literally paid to put oil in fuel tanks--not that we want that to be a long-term solution, but that's sort of indicative of the issues that we had, that we were willing to sort of go outside the market and pay generators—we were willing to sort of pay for inputs, when what we typically want to do is pay for outputs in our market. So, that's sort of some of the things that we've done historically to get us to where we are today.

And where are we today? I think we are at the point where we recognize that it's highly unlikely that we're going to get significant new infrastructure built, at least over the near term, in terms of fuel delivery. What we're really focused on is wringing as much as we can out of our existing infrastructure, or making sure that the current pipelines are utilized to their fullest extent, that our LNG facilities are utilized as much as they need to be to meet our needs, and that we don't have inefficiencies or informational problems that prevent the smooth functioning of the system that we do have. What we did last winter was do something called the operational fuel security analysis, or OFSA, which was really an effort to say, "OK, how tight is our system? Do we actually have enough infrastructure to meet our needs, assuming the infrastructure is used optimally? And then, assuming that it's used optimally, how sensitive are we to certain pieces of that infrastructure going away, whether it's because of retirements over many years, or because of critical incidents that happen and take something out of service, or how does it change when we get new, more renewables on the system?" So, that was a very big study effort with our stakeholders.

Hopefully, people at least understand where the ISO is coming from in terms of our concerns about fuel security and what motivates us to take the actions that we have taken over the last year and that we expect to take in the future. I'm not going to go through all the OFSA results. Suffice it to say that if we utilize the infrastructure that we currently have well, we should be OK, but it doesn't take much of a perturbation to cause problems. And depending on how our energy system evolves in New England, it could either get a lot better or a heck of a lot worse. And, in our estimation of the probabilities, probably getting worse is more likely than getting better, absent any action by the ISO.

So, that's sort of where we think we are today. Going forward, we see a lot of risks. We see the states investing very heavily in energy efficiency and behind-the-meter solar, and it's having a real significant and measurable effect on our system. And, in general, that's a good thing, except for some of the downstream implications. And one of the main implications is, it is leading us to an oversupply situation in our capacity market. So, we are currently buying three to 4,000 megawatts above our installed capability needs. And that's leading to very low prices, and it's leading to a lot of the existing oil units, which we count on for a handful of days every winter to meet our electricity needs, to want to retire. And our markets aren't sending, we believe, sufficient signals to those oil units that they are valuable, and that maybe some other unit, an old gas unit that doesn't have dedicated gas service, that has a relatively poor heat rate, maybe it would be more economic for that resource to go away. Instead, it's the oil units that are going away, and they're the ones that have stored fuel that we count on during these critical periods.

So, that is the backdrop, and what happened just about this time last year was that Mystic 8 and 9, which are two (by my accounting, and maybe I'm showing my age) relatively recent combined cycles that were built in the Boston area that are fed exclusively by imported LNG, so that, while they're gas fired they don't depend on the pipelines…So, they're two roughly 700 megawatt each combined cycle units that, if you look at our awesome model that I just mentioned, contribute a lot to our fuel security, because they are connected directly to an LNG facility that has days and days and days of storage, and they don't place any burdens on our pipelines. They tried to retire a year ago today. So, what the ISO did was, it took the unprecedented step of saying, "Look, we can't let you retire because of fuel security concerns." And we did emergency tariff revisions to allow us to do that. We spent a lot of time negotiating with Exelon over what the contract should look like. We then spent some time litigating over what the contract should look like, and it was very controversial, and I certainly understand why. But, based on the awesome analysis we had done, and our operational experience, we firmly believe that it was necessary to do that. So, that said, it is not something that we want to do again, if we can avoid it, and we feel an obligation to get to the root of the market problems that led us to feel the need to do that.

So, where that has led us now is to what we in New England refer to as Chapter 2B and Chapter 3. So, I'll unpack that for you. I honestly can't remember what chapters one and 2A are, at this point. So, fortunately, you won't have to listen to the recitation of what is embodied there. But Chapter 2B is really a short-term measure that says, look, we recognize that by intervening in the market and preventing 1400 megawatts from retiring in a 3200 megawatt market, we had a big market impact. And how can we, in some crude way, try to compensate the resources that were negatively affected by that? I can guarantee that we didn't do it perfectly. But at this point, Chapter 2B is what it is. We just filed it, I believe, last week. So, it's in front of FERC. I won't talk about it anymore, because last I knew there were some FERC folks in the room, and it's also not as interesting as Chapter 3.

What Chapter 3 is, is our longer-term set of market fixes that we hope get us out of this box of holding resources for reliability, and sweating it out on cold winter days. Posturing units, which means basically telling units that are economic to run, "No, we don't want you to run today, because we want to save your limited energy for tomorrow or the day after…" we want to get out of that business. In a perfect world, we'd get out of the business of monitoring the pipes too. We would put that all squarely where it belongs, in our view, in the risk manager departments of all the market participants who operate in New England.

How are we going to do that? Well, we have what will be a lengthy white paper that's supposed to come out April 1. I haven't heard that it's going to be delayed, so I expect it to be out April 1. Fortunately, I'm not writing that this time, so I'm not as front and center, but it's going to talk about three areas that we want to improve and lay out the specific market changes that we want to enact to improve in those areas. The first is to strengthen the financial incentives to implement more robust fuel arrangements. So, I mentioned that we want to make sure we fully utilize our existing infrastructure. One of the problems we have now is that our LNG facilities are not fully utilized. In fact, they're constantly telling us they're going to go out of business, which obviously doesn't square with the rest of the story I just told you, right? We're dependent on these resources. We need them to meet our critical needs, yet their owners are telling us they want to go out of business. Now, let's put aside the posturing. You know, everybody always tells us they're not making enough money in our markets. So, put that aside. There are some objective reasons to think that this is, there is some truth to this story. So, what we want to do is enhance our market so that there are incentives for gas-fired generators to go out and sign longer-term deals with these LNG facilities, to make sure there's actually LNG in the tank when we need it in the tank, and not just counting on whatever speculative LNG the tank owner may bring in--you know, one or two cargos a winter in hopes of selling at premium price time.

The second thing we want to do is reward resource flexibility. That's sort of an ongoing theme, but it's become much more important in our markets now that, A, we have more renewables coming in, so we have that volatility, but also what we've recognized in the course of our costs analysis is how vulnerable we are to disruptions in a fully loaded gas system. So, one of the themes has been to efficiently utilize all our resources. Well, if you're utilizing all your resources efficiently, it doesn't take much to knock you off that path. So, we want people to invest in additional flexibility, as well.

And then, finally, I mentioned posturing a few minutes ago. We want to enable market participants to better coordinate their use of limited energy reserves over multiple days. We don't want to be in that business. We don't want to be saying, "Hey, oil fired unit," or "Hey, dual fuel unit, I know you're economic today, but we don't want you to run today because we think we're going to need you tomorrow." That creates lots of problems in the market. We shouldn't be in that business. It potentially takes profit away from these resources, and when we try to compensate them for that lost profit, it's not going to be the right number. And there's some moral hazard involved, too, because we get resources that know we might do that to them, and they change their bidding behavior. So, all that is undesirable. We want to put that squarely back on the market.

So, the three specific things that we're looking to do include, first, a multi-day ahead market. Right now, we have a day-ahead market. We are looking to have the energy market settle up to six days in advance. Our current thinking is that we'd start with two or three days in advance (and every intervening day, of course) and work up to having longer as the market demonstrated need, and, frankly, as the software and the computer hardware improved enough to make that work well. It gets remarkably computationally complex to do a seven day, 24 hour a day market, all with different prices in every hour, to clear all that at once. So, we're going to probably start on the shorter end and, depending on need, move to a longer end.

We're looking at new day-ahead ancillary services. We have long seen an issue with our current ancillary services, specifically the reserve markets, where we pay you for offering to provide them, but if you actually don't deliver, there's no penalty for that. So, what we want to do is move to a world where we also have day-ahead ancillaries, so if you say you'll provide 10-minute reserves a day ahead, and if you don't deliver it in real time, there's actually a financial obligation. Unless, of course, you're delivering energy already, et cetera, et cetera. But if you just aren't able to deliver one of those products, you actually pay a price for that, which we think will help make it work better. And, incidentally, which still relies on the real time markets for those things existing. And so, day ahead would also include, in addition to the typical reserves that you're used to, two other new reserve products. One is a reserve product that is essentially the delta between our forecast load and the actual day-ahead cleared load, which is, frankly, fairly *de minimus*, but is important for some other reasons.

And then, finally, the most interesting new reserve product we're looking for is, essentially, replacement energy for real-time operations. So, the idea would be, we would buy a certain quantity of megawatts in the day-ahead, and we would pay whatever the market clearing price was for that. And, in turn, a resource that cleared that would have an obligation to provide energy at an offer price in the real-time, and if they didn't deliver that energy in the real-time, then they would have to buy out of their position at the real-time energy price. So, it puts a subset of generators on the hook to be able to deliver, or face high real-time prices that they have to pay back. So, that would be a very important component of it, and the thinking there is that it would give generators an incentive to engage in long-term contracting--for example, LNG availability from Repsol or from Distrigas. So, if you know that you are on the hook, potentially, if there's a contingency in real time, to provide six hours of electricity, you would make sure that you had the fuel to do that. And we would expect you're going to get paid five, six, 10 dollars a megawatt hour, depending on the day, just for saying you're willing to do that. And you would then get paid for your energy in real time, as well.

And then, finally, we would couple these things with a seasonal forward market. The seasonal forward market would most likely apply primarily to the piece I just talked about, which is the replacement energy. And that would enable people to sign, if they chose, multi-month-ahead contracts with LNG suppliers.

Because it's going to be co-optimized, all these prices are going to cascade into the LMPs, so there'd be a significant LMP effect, as well as a reserve price effect.

The only other thing I would note would be that these changes almost certainly all make sense in a world, even where we're not fuel short, but where you're facing a lot of renewables and intermittent resources, because you're going to need these same sorts of services. So, thanks for bearing with me and I look forward to any questions. And I'm sure there will be a lot.

Moderator: Thanks. I'm going to hold off on clarifying questions to the proper discussion. So, I'm going to hand it over to Speaker 3.

Speaker 3.

Four years ago a group of companies I'm associated with wrote a proposal to ARPA-E to develop what we call the GECO approach, the Gas-Electric Co-Optimization approach. Three years ago, we finally got a contract with ARPA-E, and I really appreciate the opportunity to be here and share with you what our achievements and findings are. And we believe it's pretty relevant to the discussion that we're having today.

So, the project team consists of a number of great organizations. The Newton Energy Group is the primary recipient of the award, and a second very critical participating party is the Los Alamos National Lab, particularly the group of physicists and mathematicians who came up with the unique capability to have a scalable method for transient optimization of pipeline activation. We also have Boston University, Polaris Systems Optimization, which provides the electric system modeling capability to share with Tabors and others, helping with the market design and other aspects of the project. Now, the disclaimer is very important. What I'm saying is just our opinion, and cannot be attributed to anybody else and especially to Kinder Morgan, who actually helped us a lot with the data and expertise on the pipeline side.

So, I'll start by maybe restating the operational and market challenges of gas-electric coordination, then discuss the three components of the GECO project, which are transient optimization, the concept of the gas balancing market, and how it can be used in gas-electric coordination. I will maybe touch base on the modeling tools and share with you some numerical experiments with modeling tools that we developed in this approach.

So, in terms of the motivation, this is a very good quote from a presentation made in October of last year by the Vice President of Kinder Morgan, talking about the challenges created by the change of the fleet of generating units in the United States, specifically with respect to the operation of the pipelines. First of all, we have a lot more gas that is being moved along the pipelines to serve generation, and the way its moved is very different now, especially in places like California, where you can see tremendous ramps that may be required to compensate for the changes in solar energy. And while gas-fired generators are especially flexible, they can support significant ramps, but the question is, to what extent can these ramps be supported by pipelines? We normally do not think about processes within the pipelines much beyond, well, there is gas, and we can take it, but in reality, once you start taking this gas pretty fast, that creates a very specific phenomenon in terms of how the pressure within the pipeline changes and how the flow within the pipeline changes, and at some point you may actually create an unfeasible situation, simply because you've taken this gas pretty fast.

So, all of these aspects become very important. We haven't thought about them before. And that motivated the funding of the project by ARPA-E, because they realized that it's important for supporting emerging renewable generation.

If we look at gas-electric challenges, there are two aspects: operational and planning for the long term. On the operational side, flexible gas-fired generation lacks fuel supply flexibility. And that flexibility in the electric system is very important, because we don't really have much in the way of storage for electricity itself. We don't have the equivalent of the line pack that's available in the pipeline. And the unpredictability and variability of gas-fired generation is a significant challenge to the pipeline.

If we look at the long term, then the gas fired plants tend not to procure firm gas transportation, as Speaker 1 explained. Essentially, there have been severe gas pipeline constraints that limit supply for gas fired generation.

These problems will only be exacerbated with the continued displacement of coal with gas fired generation all across the country. But we feel that what we should do is to sort out the operational challenges. If we can out sort the operational challenges than the planning challenges would follow. But if you do not do it right at the hour by hour level, then it would be very difficult to deal with this on a long term.

So, in order to do that, again, what are the deficiencies, in terms of today's coordination problem? The gas fired units are very flexible. They're capable of change on short notice. And, actually, some of these units are not even committed in the day-ahead market. They're only committed in real time. So, there's no capability, even, to procure gas ahead of time, because they don't know whether they're going to be running or not. They provide the bulk of operating reserves, and therefore they need to have access to gas to provide these reserves, and it's very difficult to forecast for them what the burn rates will be. The pipeline, on the other hand, is very unhappy about that, because they say, "Well, we don't have enough visibility. We cannot predict how much gas the electric generators will take."

So, the problem is, there are no liquid and transparent intra-day gas markets in which the gas could be bought at a price, and the price would guarantee delivery. So, we know that most gas fired power plants purchase gas bilaterally. They get it from marketers or from asset managers who manage a portfolio of gas resources, but at the same time they do not have the physical capability to guarantee delivery at the time when it's needed, because at the end of the day they are only paper devices. They do not control how the gas flows on the pipeline.

So, we really need to get down to the physics to understand what's going on. So, look a little bit at what happens in one day, if we line up the electric day versus the gas day. So, at the time when the power plants submit offers to sell into the day-ahead electricity market, the only thing that they have is effectively some estimates of the gas price that they can get from the traders and the asset managers. After that, the market clears. So, they already took a financially binding position to generate. They guarantee the LMP that they're paid. The price of gas is sort of known, but the delivery is not. Then it goes into the process of nomination. So, it goes first through the timely nomination, which is also not finalized, because most of these power plants do not have what is known as a primary delivery point. But if they are not on the primary delivery point, they can be bumped. They're typically on the secondary delivery point. So, only at about 2100 hours, when nobody's is any longer bumpable, can they have a guarantee that they will actually get the gas they need, with one important exception. They guarantee the pretty much ratable quantity of gas taken, with the same quantity every hour over 24 hours. In reality, this is not how our plants run. So, that's the challenge. And the uncertainty in that also complicates the work of the pipeline.

So, the pricing signals are insufficient. There is lack of temporal granularity. What Speaker 1 was showing is completely accurate. If you look at how much power plants will be willing to pay for gas, this is an amount up to LMP/HeatRate-Variable O&M costs, and that's a number that changes over the course of the day. Now, the gas market currently provides five prices per week, and they do not reflect intraday change in the value of gas. And we see the same thing in terms of lack of spatial granularity. Operational problems (congestion) may occur at the station level. Different compressors, different places. The prices are set at the broad zonal level, and they provide no locational differentiation within zones. So, two power plants within the same zone may be affected differently, but they don't know about it.

So, the ARPA-E funded project was basically designed to help address this issue. The project objective is to develop methods, models, and algorithms, and also create associated market design to see how this method could be actually used in real markets and also demonstrate, through simulations, the efficiency of this. So, we started three years ago. It was initially supposed to be done a year ago, but we're still working; we'll be done this summer. So, with all the technology in place, we are now finally getting to the point of conducting simulations.

So, the approach has three components. The first, at the core, is this transient optimization of pipeline operations. The second part is what we call the gas balancing market, and we'll discuss quickly what that means. And the third part is how to rely on the gas balancing market to efficiently coordinate pipeline and electric networks.

So, on the transient optimization, and why it's important, I'm not going to go through the mathematics on that. But, effectively, if you think about markets based on transient optimization, they can provide the clearing of supply and demand transactions, and at the same time determine operation regimes for compressor stations. The outcome of that would be to define the economic value of natural gas at any point in time and at any location within the pipeline. And receipt and delivery schedules could be guaranteed at a price. So, that's what we want out of this. And transient optimization as a tool is similar to how we use unit commitment and security constrained dispatch. The price guarantee works because prices are consistent with the physics of gas flow. That's very important. We're not looking at the pipelines as kind of paper devices with paper allocation of capacity. We're looking at the physics, how they actually work. And because this optimization relies on the physical flows, we know that, at the end of the day, if we get a solution, that solution would actually be implementable in real pipelines. And what it does is it provides access to pipeline capacity consistent with granular prices, rather than on a first come, first served basis, or other less efficient mechanisms.

Now, the reason why we're talking about this now, not 20 years ago, is because until very recently, it was just a mathematically intractable problem. In Australia, in the Provence of Victoria, that type of a market has been in place for quite a while, but it's not a very big system. It was feasible to do there.

How do we envision this working? You can think of a pipeline network as a trading platform. So, there is a two-sided auction that takes place. The auction is actually conducted on a pipeline network subject to engineering constraints. The buyers and sellers submit price and quantity offers and bids. The offers and bids are node-specific, and this is essentially a dynamic problem, with hourly time step for an optimization horizon--we believe it should be 36 hours. And I'll explain why. So, the auctioneer's objective function is to maximize the total market surplus over this period of time, and the result would be prices and schedules and compresser operations schedules.

So, one element of this would produce what we call the locational trade value (LTV) of natural gas. (We were told never to use the word "LMP" in the gas context. It just doesn't fly there.) So, these LTVs are highly granular. They can be determined at any node, any pipe, and they could be done hourly or on a sub-hourly time span. They're consistent with the physics of flow and with pipeline engineering constraints. And the transacting parties can have a guarantee of delivery at a settled price.

So, what are we trading? The idea is that what we should be trading is the differentials between the tradable quantities. The tradeable quantities are scheduled day-ahead, and that market is already in place. There is no need to change it. All we need is to actually start trading in close to real time and to accommodate the need of the parties to deviate from the scheduled quantities. So, what's offered are the deviations. So, it's essentially a balancing market. It's not the full day-ahead market.

So, what are the important principles? First of all, we do not believe that it's necessary to create something like a multi-pipeline RTO. That would be very difficult to do. The market could be set on an individual pipeline and could be basically pipeline specific. It could have voluntary participation. If you don't want to trade your imbalances, you can just operate the way you are today. So, it will effectively honor existing transportation rights and contracts. But you can trade your daily imbalances. And because it's done using transient optimization, it ensures deliverability. The intra-day transactions are conducted in a liquid, transparent, flexible, simple manner. Pricing signals are provided to everybody. And we have a more efficient utilization of both gas and power systems.

So, how might it work between the gas and the electric system? The market can notionally begin at the close of the evening cycle, because at the end of the evening cycle, all the transactions for the next day have been scheduled. Nobody is bumpable anymore. So, now people can actually say, "OK, I know I'm guaranteed daily delivery. All I need to do is to trade it around. When I don't need gas, I can sell it. When I need more gas, I can try to buy it." So, at that point, the power plants could submit, because they know they've been scheduled to run in the day ahead. They can submit their offers to buy gas and offers to sell gas when they don't need it. That goes into the gas balancing market. The gas balancing market should clear from 2100 hours to the beginning of the gas day, which is 9 a.m. the next day, plus another 24 hours. That's where 36 hours, the minimum, comes from. So, essentially, it can go and repeat itself every hour or every several hours. So, the current clearing becomes basically the spot price of gas in that point in time and the rest is the forwards, and people have an opportunity to revisit and sell and buy. So, this way once they get the gas prices which are locational and time specific, these gas prices can go into the electricity market and since the bids could now be changed every hour, so that would be accommodated there and we would have a very flexible structure in which the two systems would coordinate.

Now, on the pipeline side, that would create immediate benefit, because higher gas prices would be transferred into redispatch of generation away from the constrained pipeline system. It will also help pipeline customers make investment decisions, because if you anticipate the sort of scarcity price and if you can better manage your risk, you can decide how much firm transportation you need, as opposed to no firm transportation. Pipelines would benefit because they would see better granularity in prices and could more precisely identify where the problems are. Because currently they don't really rely on transient optimization. They can't quite say, "OK, what's the value of upgrading that compressor or laying another pipe?" And that would help them actually justify investment decisions before regulators, because now they could really learn something which we call in the transmission system, the adjusted production cost to assess the benefits.

On the electric side, that would support, again, trade. The procurement of reserves, everything. The gas purchases would be simplified and would have a lot more transparency. So, there are kind of numerous benefits.

I'll just go quickly with some illustrative numerical results, because we've got the SCADA data. We tested the SCADA data through the models. We made sure that the models are accurate within SCADA measurements, and then we did some simulation analysis. So, here is the data for a piece of a pipeline, I wouldn't say which one. I can't. But we have data which were from hourly metered information during the Polar Vortex period, February and March of 2014. So, it was pretty distressed conditions. The segment serves three combined cycle plants. And, essentially, we started by kind of simulating the system and then trying to do some optimization on it. So, the first question was quite interesting. What would the locational trade values look like at that period of time, compared to the market index? So the red line, is our day ahead index, traded on ICE. And the colored lines are basically hourly locational trade value of different power plants on the system, and the exit point and the entry point of supply. So, as we can see, there's quite a bit of a structure there. The second part is we said, "Let's pretend that we add some number of highly modern combined cycle plants." So, we put them in, and we said, "Well, if we add more power plants at these locations, where the existing CCGTs are, and assume that if everybody else is served as was scheduled, we asked at what capacity factors these power plants could operate, given transient optimization and the given level of supply. So, we looked at that and found quite an interesting result. We could add one more power plant that would be operating at close to 90 percent. If we add two, that goes down. If we add three, obviously it goes below. That's understandable.

Then the question was the following. What if we assumed that all other buyers at other nodes would be willing to sell up to five percent of their purchases at the prices that we determined for the base case? What would happen in the system? So, that's what happens to these capacity factors. If you've got enough trading in the system, it's essentially price sensitive demand response. You can significantly improve the deliverability of natural gas to the power plants.

So, in conclusion, adoption of transient optimization methods would definitely benefit the industry in ways beyond the obvious. Because there are a lot of things that we just can't anticipate what could happen. The gas balancing market, as proposed, would benefit both sectors. It would preserve existing structures, enhance efficiency, and enhance reliability and resilience. It could be implemented incrementally, and it doesn't probably require any major regulatory overhaul, because we're not suggesting changing the existing market, we're only suggesting creating a market where none exists. It's actually very similar to the Park and Loan service that's already in place. It's like a glorified Park and Loan service. The only difference is that we're not required that the same party should have balance buy and sell positions. We're just saying, "Well it has to be collectively balanced, not individually balanced." And the way it's procured is not on a first come, first served basis, but in a more organized fashion. Otherwise, this is pretty much the same service.

Now, why is it not easy to implement? Well, first of all, the pipeline must want it. There's got to be some incentive for them to demonstrate the benefit from that, and to find a painless mechanism that would generate more revenues for the pipelines while still not interfering with the existing market is actually not easy. On the other hand, they kind of look and they say, "Well, does it help us to build more pipe?" But maybe a solution could be to build upon the Park and Loan tariffed structure and demonstrate that they can probably get more of that service out and that helps them to increase their revenues.

So, that's one side, but the other reason it's not easy is that I just want to tell you that we built a unique modeling capability. We can simulate the interaction of the gas and electric system at an incredible level of detail, in order to test various market design structures, and it's very realistic, because it's, both on the electric side and gas side, physics based.

And one other item is that, as we have been working with that, we have realized how different the two industries are in terms of available data to do any kind of analysis and modeling. I mean, compare what you get through FERC form 715 on the electric topology side and what you can get on the form 567, and how unusable it is on the pipeline side. So, it's a huge difference. Something needs to be done, if we want to move forward. Thank you.

Clarifying question 1: I missed the very beginning. Does the model have, in your hourly intertemporal box, the ability to move the gas in time through compression?

Speaker 3: Yes.

Questioner: When you hit a constraint that binds, ideally you would want to show it as a contingency on the electric side?

If I just look at the gas alone, I'll see the price. I've got that. OK. But doesn't it have the potential to change the contingency for the operational configuration on the electric side? That is, change the outage mode of what would happen if, for example, you lost gas compression, or you lost a compression station, and then you put yourself at the constraint...

Speaker 3: Essentially, it would not deliver enough gas, and the electric market would have to respond to it.

Moderator: Is your question, is it really a security constrained optimization?

Questioner: But across the markets. I see how he's feeding it up and back, step by step, and I'm wondering if the result changes the constraints in the next step. Maybe that's a better way of saying it.

Speaker 3: Well, if the gas is not delivered then the system has to, the system has to respond. So, if you have enough reserves in the system to do that, then you're fine. If you don't, then you've got a problem.

Questioner: That is to say, you have to build in the contingency on the electric side.

Speaker 3: In a way you would have to. That's right.

Moderator: I think you'll get your question somewhat answered from the next discussion, so, Speaker 4.

Speaker 4.
First of all, I want to say, Speaker 3, that that's really a great innovation. I'm just coming here, from a power market participant perspective, to give some observations. And I'd like to raise questions, not to provide an answer.

Basically, this slide shows some recent extreme gas/electricity interdependency events. You can see the polar vortex in the system, and how it effects, in PJM, in NYISO, and the New England ISO, the availability of gas power plants. And also observe last year, in the summer, the gas leakage at the Aliso Canyon storage facility, in combination with gas pipeline outage, manifested as a max-burn constraint in the CAISO electric grid. Also, during the last month's cold events in the Pacific Northwest, we saw SoCal and PG&E city gate gas basis jump, and that resulted in severe congestion on CAISO electric grids.

So, it's getting to a tipping point, with this strong coupling of the gas and the electric systems. So, basically also, this is my comments to Speaker 2. I have found that a high capacity reserve, we have to hold on the power side. When you couple the markets, your ideal is the total reserve margin, right? To the question that was just raised, I know PJM this year will implement pipeline outages as a minus one contingency into power electric grid operation. Basically, should the gas power plant also know the information about the power side of operations? So, power shall be a contingency on the natural gas pipeline. So, it's just joined properly.

One more comment to add in is, the new power plants generally are cleaner. New gas power plants are cleaner and are more likely to be built closer to the load centers to relieve electric grid congestion. But this increased natural gas offtake from those gas power plants is actually transferring the stress to the gas pipeline networks. That is what we observed. So, gas power plants are likely to ramp up or ramp down to balance intermittent wind generation. So, under the non-firm contracts, the offtake from the gas power plants basically is transferring the dynamics into the gas pipeline networks with muted market signals and less optimal controls. So, the reliability of electric grids is now hindered by the outdated operation of the gas pipeline network. So, just to come back to the conclusion, we need a gas day-ahead/intraday spot market to replace the single day-ahead pricing of the existing distributed bilateral gas market. We want to continue that transparent centralized clearing mechanism, while respecting the physical constraint of gas dynamics and the pipeline compressors to reduce off-market gas pipeline curtailment.

So, the gas/electricity market is a seam issue. We know about ISO seam issues between markets. I think that there is a strong seam issue between gas and electricity. So, under the current separate gas and electricity markets, the gas generator is exposed to the risk of selling electricity with an uncertain ability to procure gas or interrupted supply due to gas pipeline curtailments. So, distributed gas spot markets based solely on bilateral transactions ignore gas physics and pipeline network constraints and results in markets that are less transparent, less liquid and increase the probability that gas generators will experience unanticipated curtailment at delivery. The existing paradigm of a single day-ahead settlement price is insufficient to provide transparent market signals and associated control optimization for the dynamic offtake from gas power plants, as they tend to act dynamically to balance intermittent wind and offer ancillary service. Gas spot markets will benefit from locational hourly prices for both day-ahead and intraday supply/demand, allowing pipeline operators to optimally prepare the line pack for offtake by gas power plants. Also, talking about the financial perspective, the gas futures markets may extend beyond the current limited set of gas hubs to provide perfect hedges for the individual gas generator's risk exposure to the gas price volatility resulting from pipeline network congestion.

So, what's been done so far? I think you already heard a lot, so I will skip this part.

So, basically, we need a gas LMP (I know some people don't like to call it "gas LMP," but just for the people on power side and our familiarity with dealing with LMP, I call it the gas LMP market.) So, we need a gas LMP market, coupled with the electricity LMP market, to guide the optimal operation of both pipeline networks and the electric grids. A single price for the day-ahead is not sufficient to guide the optimal time-dependent setting of the pipeline compressors for non-firm offtake by gas power generators, which may lead to underutilization of gas pipeline capacity. The stale single daily prices are out of sync with the dynamic price of electricity markets. And also, a cooperative effort is needed between ISOs/RTOs and gas pipeline operators to establish gas pricing nodes that correspond to the existing electricity pricing nodes where the gas generators are located.

And so we go further. We need a gas FTR auction to guide gas pipeline and storage investment. So, we know electric grids have experienced significant buildup and upgrades as developers have benefitted from getting proceeds from Financial Transmission Right, FTR, auctions to help finance needed transmission projects. As the dynamics from electric grids have been increasingly imposed on the gas pipelines, it becomes increasingly apparent that pipeline assets are underbuilt when compared to relatively overbuilt electric grids, and the existing storage capacity seems more and more inadequate to accommodate the increasing offtake swings from gas power plants. As a result, volatility is increased in the gas markets and the pipeline operational stress is also increased. So, currently gas pipeline construction proposals need to secure sufficient amounts of firm subscription before commencing construction, which creates high barriers to gas pipeline project investment and hinders the much-needed pipeline investment to accommodate the increased supply/demand for natural gas. Also, storage investors and gas power developers need a gas FTR market to better hedge the long cycle weather risk, as well as the pipeline outage/maintenance risk exposure.

This is the mathematical formulation behind it [shows complex mathematical slide]. I won't even get into it. [LAUGHTER] I reference Speaker 3's paper. [LAUGHTER] Basically, you can see the constraints. So, the nodal flow balance, compressor boost, the pressure limits... all those physical operational limits are included. That's why it somehow warrants the feasibility of delivery.

So, is a gas LMP market technically doable? Is a gas/electricity co-LMP market technically doable? We have availability of off the shelf, production level, large scale optimization solvers, and also we also have validated the gas dynamic models for pipeline simulation. Also, large scale computing capability has significantly improved over the last 20 years. Eventually, can a generator just simply input its heat rate curve into the coupled gas/electricity co-LMP market to sell its electricity production into the electric grids, meanwhile procuring the needed gas from the pipelines? This is just a question for smart people to answer.

And another question, on the FTR side--is a gas FTR auction technically doable? Is a gas/electricity co-FTR auction technically doable? Similar to FTR auction for electricity, we'd need monthly and annual auctions where gas power generators can simultaneously hedge both power side congestion risk and gas procurement basis risk. So, there's an arbitrage opportunity between the electricity grid congestion side and the gas grid, gas pipeline congestion. Which way's more economically efficient to do the upgrade? So, that's the fundamental economic reason for doing this analysis. And the auction model needs to pass the Simultaneous Feasibility Test [SFT] for credit adequacy. Eventually, can a generator just simply input its heat rate curve to the coupled gas-electricity FTR market to optimally hedge its congestion risks from both gas pipelines and the electric grids?

And the last ultimate question I have is, basically, ISO the independent system operators, should its role be that of a co-host of a gas and electricity balancing market? Thank you.

General discussion.

Moderator: This has been a very interesting discussion. I like the starting point of setting up the issue the way Speaker 1 did. I like the practical overview of what's going on at least in the electric operations side and coordination that Speaker 2 provided. And then we had the potential solutions, kind of looking forward, and it really does seem like the gas side is kind of where the electricity side was maybe 20 years ago, and looking at, how do you operate these markets in a more transparent way? So, with that I'm going to open it up to questions and discussion.

Question 1: This question is for Speaker 2. Were you saying that your long-term plan was, say, a week ahead for a given day, then maybe three days, and then a day ahead? Or, were you talking about 168 hour full commitment in a rolling 168 for like a week ahead? I didn't know which one you were saying.

Respondent 1: Let's see if I can say it more clearly. What we're thinking is, we already have a day-ahead. We'd have a two-day-ahead and a three-day-ahead for a single day.

Question 2: This is going to have the appearance of a clarifying question, but it's actually trying to get at something tougher. So, in the very early days, I think it was 1996 or 1997, if I get my dates right, when Andy Ott was running in parallel the LMP system, but they actually weren't using it for settlements, they were just shaking it out in PJM, and it started to produce results which didn't surprise the system operators, but surprised everybody else, in the sense that it would be going along and the price was $30 a megawatt hour, and then in some locations it was $432 a megawatt hour, so given the impact of congestion and the way the transmission congestion constraints worked, it could be that you'd have to change the dispatch of multiple units. And so, you could end up with a situation where the highest price in the system was a large multiple of the most expensive plant that was running, for example. And you could demonstrate why that would be true. And he did, and people said, "Well, how does work?" and then he went through the arithmetic, and they started to internalize this in the electricity system, and now you see this, just looking in the data, all the time. It happens all the time.

I don't have a sense at all of what the gas side is like. I understand the principle, but let me simplify it a lot. So, we'll have no storage. The only thing we've got in the short run is line pack, that's it. And if I took the 24 hour ratable take and I compressed it, and compressed it, and compressed it, and compressed it, and then I took it all out in the 24th hour, and everybody did that, my suspicion is that the machine would break, but I don't actually know. And this actually kind of matters, in terms of how serious this problem actually is. Or, is it the kind of thing where, you know, it's an issue, it's important, and economists love it, and it's more efficient, and all that kind of thing, but the capability of the system, in the aggregate, to absorb the kinds of aggregate changes that actually take place is actually quite large, and mostly what we're looking at is institutional inertia. Some want to do it, just because it makes their life more complicated not to have it. But the physics aren't going to drive us to something which is like what we see in the electric side, where you have these complicated interactions because of the loop flow effects and all that kind of thing. So, what is the scale of the problem here?

Respondent 1: I guess I'm probably in the better position to answer that, because we've done the numbers, somewhat. So, let's start with the unconstrained case. Let's say that we're looking at 24 hours, and nothing is constrained in the pipeline. Then we will see the same price in every hour, over these 24 hours. That is obvious.

The constraints here are quite interesting, because you have three types of constraints, in general. You have compressors, and a compressor can be binding at the maximum horse power. You have a maximum allowed operating pressure, typically at the discharge point of a compressor. And then you have a minimum pressure that you must maintain before you send the gas out. So, what happens is that any combination of these three can become binding somewhere, and create, first of all, price effects…again, there is a difference. When we look at it in a steady state, in order to achieve price separation, the pipe must be binding at both ends, and the low operating pressure must be binding at the receiving end to see the price separation. In the dynamic cases, they actually differ, because even with one side of this pipe beginning to bind, there would be price separation, but it would not be instantaneous. It will evolve over time and with the speed of sound. It's like a price wave begins to propagate through the pipe, and it moves with the speed of sound, which is pretty fast, but it's not instantaneous. So, in general we can see that in a meshed enough network. Or, even not meshed enough, but it's like a lot of places where these constraints may evolve. If they were evolving in the same place, we could figure it out, and then it's not really a big deal. But, as we know, when situations change in the electrical system, the same thing will be here--it will be at different points and times, and the different conditions would be merged in a different place, which is not going to be very predictable. So, we can't anticipate this price movement around the system. I don't have enough statistics so far to compare how it would look. But you saw the picture that I was showing on one of the slides, where we did see kind of jumps up and down on prices and the separation at different places within about 200 miles of a pipeline system. Did that answer the question?

Questioner: No. [LAUGHTER]. But it was very interesting and helpful, and I'm trying to think about it. I mean, I understand what you're saying, but does the price go up 10 percent an hour, or does it go up 1,000 percent an hour? I mean, I don't know. And so, what is the impact here?

Respondent 1: Well, I think the answer could be, it can move a lot, because what affects the price is not the congestion itself, the same way as in the electric system. The supply and demand do. And in this case, the supply may not vary too much in price, simply because it may have different places, but the price difference between them may be relatively small. But the demand side, being power plants at different locations with different heat rates and different LMP structures, that's where a lot of variability may emerge. So, it's like you have a lot of locations in the system with the different bids and offers. And it's the variability in these bids and offers, combined with the system constraints, that creates the diversity.

Respondent 2: May I respond as well? I, of course, have not done the kind of analysis that Respondent 1 has done. But we are always closely looking at pipeline scheduling versus end of day deliveries when it comes to constrained days. And we see a rather typical pattern. For those of you who are in the gas pipeline business, you know that the pipelines provide a cleanup cycle, which is the cycle where, essentially, at the very end of the gas day, sometime around eight or nine in the morning, they allow a shipper to correlate their final nomination to what their actual take was. And we find, across the board, that it is very, very typical, during that cleanup cycle, in many different pricing regions, for there to be hundreds of thousands of dekatherms of gas that get kind of cleaned up, whereby the nominations get reduced down because they didn't take that amount of gas. And I think 40,000 would be enough for about a 600 megawatt power plant. And you think about the time of that, that's happening at nine in the morning. So, that's right after power plants ramped up and would have needed the gas. So, I just want to express that the magnitude of balancing system-wide, versus shipper by shipper, as you and I discussed earlier, and putting a price on that is very, very significant from a pipeline utilization standpoint.

Respondent 3: I think, too, that the answer to your question is somewhat system dependent. In other words, different systems have different capabilities and excess capacity to operate--whether they have storage, whether they have their pipeline system, how long their pipelines are--it seems like those all are part of the factor of whether they have physical surplus capacity to operate within or not. And that would dictate, I think, whether you would see these prices really start to separate, based on those conditions.

Question 3: Speaker 2, you talked about a number of new products. And I was a bit unclear as to why the product to essentially commit a generator a day in advance, why that's not already the incentive, and why they need the product in the first instance. Because it just seems to me that if they're infra marginal they get a day ahead position. It seems like a redundant product, then. If they're not, and they're just barely off of it, wouldn't they have an incentive to be dispatched in the real time, if they become essentially marginal in the real time? So, what is the product giving you that you don't already have?

Respondent 1: I assume you're talking about the replacement energy product, which is sort of the most significant new one. And what it's giving us that we don't have today is generators who are not committed in a day-ahead market. So, this is specifically exclusive of that. We would have an option to force them to generate. And if they didn't choose to generate in real time or were unable, they would have a buyout provision. So, it's really that they would be selling us an option, and they would get an upfront premium for that. So, this is not resources. We don't really have a problem with resources that get day-ahead commitments to produce. What we do have a problem with is, we clear all these units a day ahead, then some of them don't produce, and we then look for the fallback generators, and those are unavailable, because they didn't make fuel arrangements. Does that get at your question?

Questioner: Oh, I see. So, it's basically an inducement to get a fuel arrangement, and that's the basis for the…

Respondent 1: Yeah, and you might wonder why we're only getting around to this after 20 years of operation, and the reality is, we used to get that for free. When we had a fleet full of oil units and not so many gas units, all the gas units could get gas, because we didn't have much demand on the system, and then we had tons of oil units, and they just had the free oil in the tanks. So, even if we implemented this to the market 15 years ago, the price would have been zero all the time, or the only thing you would have priced was the outage risk in real time.

Questioner: I guess the idea here is that you need this because the real time is a bit more brittle, and you wouldn't now count on resources that you would otherwise would have had. In the real time, units become unavailable.

Respondent 1: So, they were implementing a couple things, and one of them is, we're going to true up to the load forecast. So, let's assume we true up to the load forecast and that's always correct. If nobody ever had an outage, we wouldn't need this service. But life happens, so.

Questioner: I had a quick question also to follow on. You said you were going to try to expand, maybe to six days or maybe even more, but six days in the day-ahead perspective. And then you also mentioned a load forecast sort of differential contract. Do you anticipate the load forecast differential to be sort of financially settled? So, a financial contract? Basically, trade to try to make sure your forecasts are as good as possible, or is there another mechanism in there? And then, would you have virtual trades throughout the whole period?

Respondent 1: I don't know the answer on the virtual piece. Up to six days, that's sort of the maximum we're looking at. So, we have a day ahead now. We're looking at two days ahead for the same real time, and then three days ahead, and then potentially expanding it, depending on how liquid that is. I think the expectation is that we would have financial players in those advance markets, just like we do in the day ahead today. I think that would be important to have. The piece that you talked about, which is the true up amount, would really be a lot like the replacement energy, but the expectation is that the resources would actually run. It wouldn't be a contingency. It would be, we're going to enter into a forward contract, so let's say our load forecast is for 20,000. The day-ahead only clears 19,000. So, we're 1,000 short, by our forecast. And put aside what it does to the riskiness of the day ahead market and stuff like that. We would pay an extra 1,000 megawatts to say, "Look, we're going to run you in real time. We're going to contract with you in advance to do that." I think that piece (and this where I'm talking a little bit out of school, because I'm not the designer) is important, because if you're going to buy the replacement energy, in order for it truly to be a replacement, you have to have fully met your expected real-time needs. Right? And if you don't true up the day-ahead and real-time in that way, you might have this persistent shortfall which you're actually covering through your replacement energy. So, I think that shortfall bit is to make sure that, when you're actually going and buying the option contract on replacement, that's truly what you're getting. You're not actually mingling those two things, which have different values. Because one's going to run with 95 percent certainty, and the other's going to run with five percent certainty.

So, I think separating those two is an advantage, but, like I said, I'm talking a little out of school on that, because I'm inferring that from what I've read, which is incomplete.

Question 4: So, I want to be a little contrarian here. It sounds to me like we are very much in search of a problem. As has been noted, there are reasons why we needed LMP pricing in the electrical world. All of your presentations seemed to ignore the whole structure of the gas market and its property rights. Companies such as mine invest five, 10 years out. We have a completely dysfunctional electric market. It has too many reserves, so, therefore, the generators don't get properly compensated, and therefore, they don't necessarily sign up for the kinds of contracts that you would like them to sign up for. We have very functional gas markets. Supply and demand actually works. When there's scarcity, we have high prices. My company has tons of industrial customers. They switch to oil. They get off the system. DR exists. We manage it. We manage it very well. We have transparent pricing. We have ICE (Intercontinental Exchange). And granted it's not always liquid all the time, but it's pretty liquid. It seems to me that the only times we have issues are when we have a polar vortex, maybe a couple of hours a year, and is it really worth undermining a market? It's kind of funny that you said the gas markets are 20 years behind the electric. I would say they're 20 years ahead. They actually respond to supply and demand fundamentals, which our electric markets do not do at all. Partially by design, but partially because they're so darn mitigated at this point. They're really not markets.

So, why are we doing this? And I'm excluding New England. I do recognize that New England has perhaps a build problem. But, otherwise, I don't really understand the whole push. And I'm not an economist. I realize that perhaps we'd like more transparency, but it's efficient. And marketers are doing everything that you've talked about. They balance. You just don't see it. I admit the transparency may not be there. So, why upend and industry that's basically functional to accommodate an industry that's basically dysfunctional?

Respondent 1: I'd love to take that one. So, we're in a situation where merchant power generators are the largest users of the system. Right? And they're not contracting. They don't have contractual relationships. They're totally reliant on interruptible power. I think it's certainly fair to observe that that system has held up, to date. The question is whether, on a going-forward basis, that is going to be able to continue to send the right kinds of investment signals to channel capital. When I have conversations at FERC, for example, one of the analogies I use is, is it better to subsidize coal inventory because you're worried about resiliency? Or, is it better to close the contract gap between the largest user and the pipelines? And I understand the role that the marketers take on here. I would observe, in that context, that the majority of pipeline capacity that has been deployed has been producer push and marketer driven, and only to a limited extent supply pull. And when it's supply pull, it's virtually always LDCs, rather than power generation. And so, the fundamental question is, are we efficiently allocating capital? I understand that there are parties that benefit from the system. I think our proposition would be that having more efficient and transparent price signals would more efficiently allocate capital which would benefit rate payers, shareholders and the environment. And I would further note, and this is kind of like, when there's a cold day asking, "Where's climate change?" But, I mean most of the midstream companies right now are struggling terribly, from a shareholder value standpoint. So, certainly, there are investors…I work closely with an investor that has $6 billion dollars invested in gas utilities who agrees with us. Because he's concerned about what the implications of the current incentive structure are to the health of the industry and shareholder returns. But I complete appreciate your point that the system has generally held up. There's been a few belt and suspenders types of approaches, as we know. And, certainly, there are incumbents that benefit from the status quo, without a doubt.

Questioner: If I could just respond. It's interesting. I don't disagree with you about the concerns, but getting transparent price signals is not the problem. It's getting generators revenues. What I hear you saying is that you want them to invest in more firm transmission. That may or may not be a good outcome for consumers long term, to have every generator investing in firm transmission, but, more importantly, they're not getting the compensation signals. So, all the price transparency in the world won't change a generator's risk profile in investing, just because the prices are out there, if the compensation's not out there. So, that's something, from a societal perspective, where we need to decide whether it makes sense to have all these generators paid more to buy "firm" transmission, and whether that's more efficient than the system we have today.

Respondent 1: Right. And, to your point, when you look at the Levitan Report (the Gas-Electric System Interface Study) in the EIPC (Eastern Interconnection Planning Collaborative) process of 2015, it's exorbitantly expensive for generators to back up all of their capacity supply obligations with firm transmission. That's not feasible. But I do think that some of the roads that, for example, as Speaker 2 just explained, ISO in New England is pursuing, of incentivizing, or at times sort of compelling, generators to back up some of their supply obligations with fuel supply arrangements, that's all fair game, as well. I mean that there are kind of a multiple parts to this equation, but, as you know, I believe that price coordination is one of those elements.

Question 5: Yes, thank you. I want to follow up a little bit up on the whole question of what will be the response here. I do get the intuition and the understanding that you'd like to see essentially LMP-type pricing here for gas supplied during intraday markets. I'm trying to get a sense of what the elasticity response will actually be, and I am thinking about New England in this. During the summer there's vast excess capacity on the pipelines, so help me here. Is there a problem, ever, in delivering gas in the summer? In the wintertime, we have the constraints that arise because the gas LDCs are meeting home heating demand, and I don't expect that's very elastic or price sensitive at all. And so I'm trying to get a sense of what you might actually think would be the responsiveness here. And, with respect to the generators, if gas prices are generally going up, as they do in the winter, the oil can become merit order dispatch, and then the oil units runs, so the gas doesn't even win in their auctions.

And, finally, trying to think through the physical response to all of this on the pipeline side, if I understand you right, what I guess you would see would be some incremental demand for more compressors, perhaps, that would be able to pull gas faster into a region than would otherwise be the case. But how would that price signal be registered in providing such compressors, which are rate-based and not in the market? I'm just trying to think through what the actual physical responses are to the price signals and wondering how much it will matter.

Respondent 1: Let me try to answer that. Definitely, once you implement the transient optimization, the way the pipeline would operate compression will change. And it will change more dynamically in response to the pricing signals coming from the supply and demand. The way it is now operated, it doesn't look at how much revenue it is going to get from a given receipt point and how much cost occurs at the given delivery point, or the other way around. So, the economics of how you would operate compressors will be different. And that would be the response.

The other side of that response would be more granular pricing when there will be constraints in the system. I'm not saying there always will be. It's just a good business practice to run compressors more efficiently. But when they are constrained, then they will determine who is willing to pay more for full capacity on the pipeline, in the way that that is not done today.

Questioner: But you're effectively dispatching the compression.

Respondent 1: Yes.

Respondent 2: I'm going to harken back to Professor Hogan's scholarship at ERCOT, where even the slightest disturbance of scarcity price signals has implications for investment. And I think, when we talk about how we want price signals to be triggering. So, we've heard Respondent 1 already point out that that price signal might actually trigger demand response in some instances. It might trigger gas storage. It might trigger compression. But if we don't have efficient and transparent price formation around scarcity events, then we essentially get none of those things.

***Question 6*:** I guess I have a little bit different perspective than the person who asked Question 4, in terms of how functional this gas market is for supporting its largest customer. And one of the things that I was just sort of interested in the thoughts of the panel on is the fact that a lot of the focus was on issues around intraday gas needs and intraday pricing. But kind of buried in Speaker 3's presentation there was a statement that caught my eye. It seems like low hanging fruit, from the gas generators' perspective, in terms of things that could be improved in the gas market, and that is the fact that the gas market only provides five prices a week, but we have seven days a week. And that's, of course, because typically the gas package for the weekend trades as a three-day package: Saturday, Sunday, Monday. And that gets even more interesting when you have holiday weekends, and then sometimes you have holiday weekends with changes in months in the middle of them, so you get these weird gas packages. But one of the things that we see fairly frequently is that for better or for worse, a lot of the holiday weekends, particularly, seem to coincide with times when you can have extreme weather events. So, we've seen just a lot of examples--President's Day weekend, Martin Luther King Day weekend, the New Year's timeframe--and then we've had some good examples, I think, in New England around Labor Day weekend this last year. Where the first, say, couple of days will extremely mild weather, and then you'll have, rolling in right at the end of that weekend, either hot weather, in the case of Labor Day weekend, or extreme cold weather, as we've seen sometimes, recently, on President's Day and Martin Luther King days. That creates a real challenging situation for the gas generators trying to figure out how to purchase that product and leads to some, I would say, very inefficient environmental answers, because you end up getting stuck buying ratable volumes across that four-day period. You've got to figure out something to do with it so, you end up running the units through days when they're not really needed. And, therefore, you tend to do it at very inefficient levels, and then you get into the extreme day, and you often don't have as much gas as you'd like. So, I'm just sort of curious about what it is on the gas side that is driving that kind of persistence of the multiday gas package and why there's maybe a resistance to simplifying that. It feels like very low hanging fruit to get better price signals and better use of the resource if we could split that up.

Respondent 1: One of the really great benefits of the natural gas market and its function is that it operates largely bilaterally. And, of course, one of the great challenges of the gas markets is that they operate largely bilaterally. [LAUGHTER] And so, ultimately, I don't really know what the answer to your question is. I would respectfully suggest that a lot of what you've heard from this panel is implicated in what I call the "rational commercial stalemate," where the incumbents (and those incumbents are essentially the marketers in the LDCs, the pipeline, and the merchant generators) derive benefit from the system the way that it exists now, notwithstanding the fact that it doesn't operate as efficiently as it could. And so, while it's not directly responsive to your question, my proposition is, how is that stalemate going to get moved forward? And there are a lot of different manifestations of that stalemate. I would imply that maybe that's one of them.

Respondent 2: I would just concur that changing it so there were at least seven prices a week would be very beneficial. We're constantly running into those issues for everything from market monitoring, to scheduling, to our day ahead market. So, I mean I don't know what it would take to change it, but I'm 100 percent with you. That seems like it would be a big improvement.

Question 7: I think Speaker 1 and Speaker 3 laid out the case for the idea that if we were to do a gas dispatch and to do it differently, there would be implications for how you would run your systems. And in California, as we're really working to both ramp up really fast and trying to reduce the amount of curtailments for the clean generation that we do have on the system, if something like this were in place tomorrow, and we had this market up and functioning, how would you approach your dispatch differently? How would you approach what you would do in your control rooms differently?

Respondent 1: Well, I'll do what I can to speak for our operators. I am guessing they would feel that they could sort of back off on a lot of the modeling in the gas system that they do. I mean, we've hired a gas specialist, and their job is to get intelligence on the gas systems to support a model that we've developed on pipeline flows and gas availability and stuff like that that our operators somewhat resent having to do because they look at that as something that should be somebody else's problem. They should be able to focus on their own knitting. And I think the biggest thing would be that going away and the confidence that the gas system would respond as well as it possibly could to contingencies on our side. Now, I think people worry, "We have a contingency. Is the gas side (maybe because it's a weekend or maybe because it's three in the morning) really going to respond optimally and in a way to sort of wring as much potential out of the gas system as possible?" So, that would be my sort of immediate answer.

Respondent 2: I don't see our operation fundamentally changing. Our variable demand, as represented by the net load curve, will be what it is, and that's what we're trying to follow. I think what would change is the dynamic nature of the pricing inputs. So, rather than having an index that is stable over the day, it would be dynamically changing, and that would allow us to ration or dispatch resources and kind of get the gas and price it when we most need it. And I think it would be mainly driven by the fact that the dynamic nature of the gas price will now adjust for those conditions, and it would allow us to optimize better.

Questioner: Just one really quick follow up to that. If you knew better the cost of gas generation, because we had better gas prices as an input for this, if you could see that better, do you think that would change, longer-term, the products that you would use for your steep ramps up and down? Do you think that knowing the true cost of being able to respond to that ramp is going to actually change how you are responding? I would hope the answer is yes.

Respondent 2: Yes, it could, because I think, if the cost of the ramp became high, you would then get other products that potentially could ramp, whether it be electric demand response or electric storage, to help navigate that ramp, and those prices would be sending signals for those other capabilities to come into the system. So, I think it would.

Respondent 3: And, at the same time, the pressure placed on the pipeline would be mitigated. So, it would benefit both industries.

Respondent 2: I didn't mention it earlier, but, as a result of Aliso Canyon, we do enforce, on the electric side, a gas burn constraint. But it's not driven by the gas price. It's just a hard constraint over the day, and I'm just trying to shape the gas burn when it's most needed. The price sensitivity would add another element to that, but we're already effectively optimizing on a limited amount of gas burn at times.

Question 8: I've got two questions. One's for Speaker 2, with regard to the replacement energy product and sort of how that obligation relates to the obligation to perform as a capacity resource in your markets. The question for the rest of the panel is, how do we go from where we are to where we might want to be? Particularly given, as was pointed out, that, first of all, this is a physical rights market. This is a market dominated by LDCs with property rights, whose purchasing practices are regulated, at best, at the state level, yet FERC has regulation over these markets. So, I'd like to get people's thoughts on how this thing moves forward.

Respondent 1: We view the replacement energy product and the capacity resource obligation as compliments. In all fairness, when we first developed Pay for Performance (PFP), we hadn't identified the particular nature of this problem, and we think it addresses lots of things. And the primary thing PFP does is it gets the scarcity price right. I mean, now that we have PFP, it's really semantics whether you call the capacity market the capacity market or just an extension of the energy market, because you're really selling peak scarcity prices forward.

But it turns out the problem that leads to people not making the fuel arrangements is different than the one that PFP solves, which is getting the prices right. It's a combination of the fact that people need to make fixed upfront investments and the fact that, if they make those fixed upfront investments, they actually change the price in a material way. And, well, you could solve this by making the PFP penalty very, very high. That would distort other parts of the market, because you would then be signaling, when you're scarce, that electricity's way more valuable than it truly is. It's really a non-convexity, because you have this fixed cost that needs to be incurred in order to deliver later. The best way that we see to do that is, instead, in conjunction with PFP, engage in an option contract with the resources that you think you're going to need. Like I mentioned, I'm probably not going to be able to do justice to this in a verbal answer, but this will all be laid out in the paper that ISONE intends to put out on April 1.

Moderator: What about the second part of the question about how do we go from where we are to where we think we want to be, if it's where we want to be?

Respondent 2: That's a good question. I can kind of see that if we try to go incrementally, we probably can't, except that we need a willing participant on the gas side who would agree to be kind of a guinea pig. And that could be some pipeline company which says, "Well, let's try to optimize, because we now have optimization tools we didn't have before. Let's try to optimize park and loan service. Let's see how it works. Can we take this park and loan service and, instead of doing it on a first come, first serve basis, do it as an auction?" And if that works, then it's very easy to take the next step. The other option would be that, if it's an institutional problem, perhaps some private equity group would take over a pipeline. I don't have any other advice.

Respondent 3: This is just my conjecture. Maybe the ISO can have a clearinghouse functionality first. Basically, establishing ways to be recognized out there. There's a figure called a gas marketer. Somehow, they can clear through the ISO. It depends on how much ISOs can get the information centralized. But then, later on, we added all marketers into the market. So, actually this is basically how Europe is doing that—with a centralized, transparent functionality. Then, eventually it's like a diverse market.

Respondent 4: So, the panel that we heard from earlier on Order 1000 was also wrestling with the question of, how do we integrate competitive forces into what's fundamentally a cost of service infrastructure business? And let me start by saying that, notwithstanding this discussion about price formation, I think it's really important that the pipeline industry remain fundamentally a cost of service business, because that's the way that they can obtain revenue certainty, by which they can obtain financing from Wall Street. That being said, there are kind of two things that are going on that are in our favor. The first one is, as I showed earlier (and probably some more empirical analysis is worthwhile--this is mostly sort of qualitative) is that the value of point-to-point capacity, by which pipelines are compensated, is going down. And we're seeing a huge amount of capacity on existing pipelines. And many of those pipelines are looking for new ways. They did do things like postage stamp rates to generate new revenue streams in light of the fact that the value of their point-to-point capacity is diminishing. The second potential thing in our favor is where we're seeing some pipeline expansions, it might be in the interest of a pipeline that's seeking to expand in order to gain, let's call it "social license to operate" approval, to be willing to take a step forward to bring forth some of these pricing deficiencies. And I think that can be done through a pricing pilot. I mean, it doesn't need to be top secret. We've had extensive conversations with commissioners and FERC staff around their precedents for pricing pilots and allowing incentive rates of return, where the pipelines still remain fundamentally cost of service regulated, but are able to earn additional revenues and return by providing these kinds of services. We believe strongly that just starting one of those pilots and starting to record the requests and starting to see how that plays out is a beginning point. But, ultimately, I guess we'll see.

Question 9: I have a few questions. I think they're relatively short. The first one is whether, under this proposal, generators would be able to change their bids in real time? There are real time bids in real time, but I don't know that they currently are in the markets in general. And how would that be addressed, in terms of whether there's any market power or other concerns, and have you thought about that? The second question is more general. There's obviously been a lot of flexibility added to the system after the polar vortex in 2014--oil backup storage, LNG, other types of reforms and activities. I'm curious to what extent you've seen those be successful. We had a very extreme cold weather event at the end of January this year that did not result in significant pipe price spikes. Have some of the reforms that the market has actually done actually dissipated some of the need for this type of thing? And my third question is for Speaker 1. Is it EDFs policy not to oppose new pipeline capacity into New England, either as a condition for people doing these kinds of reforms, or just in general, if these reforms are implemented?

Respondent 1: EDF hasn't opposed any pipeline.

There was one affiliate transaction project, I'm not going to name names here, where they turned back capacity, left their current legacy supplier high and dry, so that they could build an affiliate pipeline, for which they were the only, the affiliate was the only shipper. But that was an outlier.

Respondent 2: Since we're going backwards I'll answer the middle question now. I think it's safe to say we've seen noticeable improvements, over time, from additional dual fuel capability. I don't know the number off the top of my head, but I believe it's in the thousands of megawatts, which is great. And we've seen other things that have changed. The flip side is, we've lost a lot of old oil and some coal. We're losing Pilgrim at the end of May. That's 900 megawatts of baseload capacity that doesn't lean on the gas pipes at all. And we're losing lots of other oil over time, so it's really an interesting sort of race between the market changes that can happen in a positive direction…some of them are due to just natural market forces. Some of them are due, presumably, to some improvements we hope we're making. It's that, versus the fact that we're sending retirement signals to a bunch of these old oil units, because their capacity factor's three percent. It's really hard to make a living at a three percent capacity factor, especially because what it really means is that, whenever you run, you're at best a break-even proposition. You're really just in it for the capacity payments. And, this year, you're down to $3.80 a kilowatt-month for three years out. That's not a lot of money to run your 40-year-old oil unit. And what the offset does is it tries to gauge the improvements we're seeing, and we try to incorporate those and even project them with all the renewables the states are buying and see how that compares to the losses that we're experiencing through retirements and other things.

Respondent 1: With regard to the first question, I think you're going in early bidding.

Respondent 2: We currently have hourly bidding. The operators were initially skeptical, and that's a nice way to put it. They actually now have come around to recognizing that hourly bidding's been essential for getting the gas supplier generators to be much more willing, and before they were rightfully recalcitrant to get gas intraday and come online intraday when we need them. It's been a huge help.

There is monitoring associated with it through the market monitor. I guess I probably shouldn't characterize how successful it's been, because I'm sure there's somebody in the room who's had a bad experience with that. But from the 50,000-foot level, at the very least, it seems like it's enabled it to operate in a fairly effective way.

Respondent 3: For the CAISO, we have hourly bidding day-ahead, and then we have hourly bidding in real time 75 minutes before the hour starts. We are making some enhancements with regard to the startup and minimum load or the commitment cost. There's a limit on how much you can bid those that is tied to the gas indices, especially on those Mondays after the weekend, and we're looking to make some improvements there to make them more responsive to the changes of conditions.

Respondent 2: Our market monitor has protocols to deal with intraday gas because they recognize that the day ahead index is not very helpful. And it is explicitly intended to allow somebody to say, "Look, I've got to pay 12 bucks. I know day ahead was five, but it's 12 now, and I can demonstrate it through whatever means," and it seems that that works, and it clearly makes a difference.

Question 10: I guess the one question I have with respect to the more granular spatial and intertemporal price is whether or not there are many studies out there that have gone and tried to see what the potential gains are. Just, empirically how much do we think this matters? And those impacts could be in terms of reductions in production costs, underutilization of capacity, or even some sense in which the prices are pretty competitive, and the extent to which those might be biased one way or the other, compared to what we would get if we had a full blown intertemporal LMP-type model. And I'm just wondering, is there any study of that, and, Speaker 3, is that something you folks are going to be looking at? And, if not, it seems to me the first thing to do is to analyze if there's much of a gain here, rather than kind of setting off and trying to build the model, if there's not really a problem.

Respondent 1: Well, that's an excellent question. And some preliminary results we haven't actually published yet…we're looking at the improvement in social welfare, and the figures are like, maybe, seven to ten percent, which is not trivial, I think. I mean, obviously, you wouldn't see, like, a 20 percent improvement, but --

Questioner: Is that seven or 10 percent across the whole year, or seven to 10 percent during certain periods when there's a need?

Respondent 1: During a certain period of time when there were severe conditions. I completely understand the skepticism. On the other hand, let me pose the question in a different way. There is the capability to optimize the system and produce benefit. And we understand that. Because optimization does that. Once you start optimizing, then the next question you will ask yourself is, what is my objective function that will be optimized? It's a very simple question. Say, well, that pipeline just minimized the fuel cost. And now, that may be a legitimate objective function, but then you can say, "Well, actually, this is not the right objective function to use. The right objective function is to maximize the market surplus." And once you do it, then you got the prices for free. Why would you turn them down?

Question 11: I think there's been a lot of discussion over symptoms of what we see in the natural gas system, where we see opportunities, we think, to optimize the organization of merchants in pipeline arrangements, and then we kind of jump straight to some proposed solutions. I would rather kind of dig down and say, all right, well, what did we actually learn from the symptoms that we're identifying? What's the source? That is, separating symptoms from the source of any perceived problems. And then, from that, maybe we can discuss what the policy implications are.

So, a lot of it, goes back to conversations on, "All right, we don't see intraday liquidity." A lot of these questions came back up a few years ago, when FERC was doing gas/electric coordination. And there were a lot of questions along the lines of, "All right, well, let's look at reformulating the nomination cycles." And then there were a lot of looks at liquidity. So, it does beg a question of, is the liquidity not there because the demand's not there? Is it that we don't see enough merchants valuing flexible pipeline service? Sort of a market design question on the electric side. And then, on the pipeline side, if, in fact, we do see the merchants valuing it, then why wouldn't the pipelines be responsive? Why are we seeing some pipelines offer more flexible services and ratable takes? Are there some legal barriers here? Is the fact that things are going away from point to point mean we need to rethink property rights and the way things are defined? Are there more network externalities? Is there market power in some of these areas, where pipelines may not be responsive even if merchants are properly incented to contract for flexible services? What are the marketing government failures that are actually present here? And only from there can we kind of identify the sort of things that would need fixing. Thanks.

Respondent 1: I can respond anecdotally. So, what was one of the first things that CAISO did after the Aliso Canyon? The facility was limited to such a great extent. One of the first things the PUC did was they tightened balancing requirements for people that were taking gas out of the system. So, that's just an indication that tightening balancing led to more efficient utilization. That's one.

I think, when we look at events like the polar vortex of 2014, hourly reoffers has been the most important policy response that has mitigated price spikes during events like that. I guess I don't really have anything more to add to that. I think there is certainly some episodic evidence that doing things like this provide benefit. There are analogies that can be carried forth from other markets, if that's helpful.

Question 12: I'm puzzled about a statement that was made that the gas pipeline business is facing sort of this inability to remarket capacity that's been released coming off contract, and so forth. And it puzzles me, because, unless demand is going down, it must be a change in behavior. Are LDCs changing their ability, or what is the cause for some of this that you're describing?

Respondent 1: So, actually *SNL* publishes, on a periodic basis, the list of contracts that have been turned back on pipelines across the country. And the list is getting larger, not smaller. And the fundamental cause is because the systems are getting built out at the same time that you've got geographically dispersed production that diminishes the value of point to point capacity. So, that, ultimately, is the cause, but I'm not a market participant. I have no money invested in this. (Actually, I couldn't have my job if I did.) But the people that I work very closely with are investors in the midstream segment, and they strongly support the kind of platform that we're advancing, exactly because they're concerned about the health of the industry and the way that the current system allocates capital. I mean, I don't have a better answer than that, but that's real. We meet with these folks all the time. They are one of the largest investors in the midstream space.

Question 13: Earlier, you mentioned the gas burn constraint. Did you price that?

Respondent 1: Yes, the gas burn constraint, when it binds, it will affect the prices.

Questioner: And it's real time, or a day ahead as well?

Respondent 1: They can do either one. And what it does is, gas prices going up in an area will naturally push electric supply outside the area. So, sometimes that's sufficient. But if we are limited in our gas burn, we will put that constraint on, and it will basically force the electric generation outside the area as well, which can then cause congestion on the electric system.

Questioner: The other question is for Speaker 2. Is your replacement energy product that you're talking about nothing more than just a day ahead, real time, 30- or 10-minute reserve product? You said it a couple times. I can't figure out what's different.

Respondent 2: We would have both. We would have a reserve product that would settle against real time reserves, and it would be co-optimized, and it'd be a separate thing which says, "Look, if we call on you day ahead, you are obligated to run or pay back at the real time price." That would be different than the reserve product, which is, "If you're not providing reserves in real time, you would pay back at the reserve price."

So, they're different in that way. Because the reserve price is going to be different than the energy price. Right?

Questioner: Well, I understand that energy assignment, but your replacement energy assignment, I don't see the difference between that and the reserve. That's what I'm missing.

Respondent 2: Yeah. This is sort of my first public running out of this, so I don't have all the answers down in terms of how to phrase them in a sensible way yet.

Questioner: And one more piece, and I guess this is for Speaker 3. In the abstract, all the constraints you're looking at could be put into the electric commitment dispatch, right? And vice versa. And I think you commented that

that's not realistic or may have institutional regulatory problems. If there are these kinds of gains, don't you really need to iterate more? I mean, it would almost seem that you'd exchange prices up and back every hour, something like that. Isn't that sort of the implied by what you're doing?

Respondent 3: That's a very good question. I mean, the question is, institutionally, how many iterations can you really do within an hour, right? So, it's a challenge. So, six would be actually very optimistic, I would say. So, we're learning that, if you do it every hour and you do it kind of dynamically, you can say, "Well, actually, dynamically it will converge." And, in the same way, you do not really iterate day ahead and real time multiple times. So --

Questioner: Well, but you could. I mean --

Respondent 3: Well, you could. You could run stochastic unit commitment, and that would be one way of doing that. So, it's a good question. This is what we build the tool for, to experiment with.

Respondent 2: I think I formulated at least a partial response to your question. So, remember this is all co-optimized. So, prices cascade, and the replacement energy product doesn't have the 10- or 30-minute requirement. So, we'd still buy 10 and 30 reserves a day ahead, and then we'd buy this replacement energy product, which might not be able to be online for two hours. So, when you do the co-optimization, those are going to be presumably less valuable than the others, and you're going to hopefully sort correctly. Presumably, the fast responding units are going to end up in the 10- and 30-minute bucket, and they're going to be worth, presumably, at least as much as this replacement energy.

Questioner: So, it is another reserve product with a kind of…

Respondent 2: Yeah, and the quantity's going to be determined differently, because we have NERC things that say 10 and 30. The numbers we've been throwing around are two to 3,000 megawatts worth of reserve product. I don't know what the length of time associated with that is. I just don't know the answer yet.

Questioner: The concern I have is that when you start doing that, then you may be bringing out a whole bunch of stuff at minimum to satisfy it. And that has a whole other distortion impact.

Respondent 2: True, although, remember, we're going to be price cascading. So, like those, presumably it's going to be expensive to do that. And that's going to make that product expensive, and everything else…

Questioner: Exactly. Those kinds of reserves are expensive.

Respondent 2: They may be, and that's why there's going to be, I'm sure, vigorous debate in New England about how big that tranche is.

Question 14: What I've heard today actually are some interesting potential ideas for here in California, because we do have some very real problems, and I also want to lay out sort of being the ghost of Christmas future, since you're the ghost of Christmas present, in terms of where we're going with this. California has successfully built about 16,000 megawatts of new gas, very efficient fleet. We've got a lot of renewables that we brought online, and this has represented a very interesting challenge for the ISO, which they're dealing with pretty well. The problem we face, certainly with the gas fleet, is that the existing infrastructure is pretty pathetic. You mentioned Aliso Canyon at least a half a dozen times today. So, we have a storage system that shouldn't have leaked, but leaked. You had the San Bruno incident that happened some time ago, on a residential level, but we also have three physical constraints on the system in southern California which have had significant ramifications on my member companies, who are generating electricity there at a significant cost in southern California.

And so, the issue of going forward, as someone mentioned earlier today, is, well, the rest of you are reveling in the fact that you replaced coal with natural gas. In California, gas is the new coal. OK? And so what we're hearing is a lot of people wanting to do away with gas completely in the fleet. They want to basically electrify all the homes in Los Angeles, and all of these are very interesting things, but the problem we've got is, we currently have an existing infrastructure that needs to be upgraded. You can trade in your car next year, but if you need a new brake job today, it's probably prudent to take care of the brakes. And that's kind of what we're facing today.

So, the question then is, how do we basically find resources available to beef up that infrastructure, in anticipation that it's going to be shut down sometime in the near future? I think we're going to be facing a major policy question here in the next few years whether any of that makes any sense. Because for the current structure in California, you need the gas fleet in order to make the solar fleet work. Because even in California, the sun does go down on a frequent basis. I think last year CAISO had almost a 15,000 megawatt ramp. So, this is pretty significant, and the question is not about correcting minor inefficiencies in the existing gas infrastructure. It's the fact that you have an infrastructure that's falling apart, and how do you put enough resources in it to keep it around long enough for this transition? True or false? [LAUGHTER]

Respondent 1: I think you outlined the challenge correctly. And it's not just the electricity infrastructure sector. It's the multiple sectors, and how do you bring these sectors along at the right time with the right level investment, knowing that some of these things are going to not be used in the longer term, and how do you transition this? And I think that's part of the challenge that we're facing. I don't think that challenge is unique to California. I think that challenge will be faced in various forms in other places. So, I think it's a general question.

Wednesday, March 27, 2019
Session 3.
Utility Liability: The Pros and Cons of Socializing Risks

The liability of utilities for damages or injuries caused by them or their agents in the course of meeting their service obligations has been an issue in writing both laws and tariffs for some time. Recent issues involving electric utilities and gas companies in both California and Massachusetts have raised the profile of what had heretofore largely been below the public radar. Setting aside the specifics of the California and Massachusetts cases, what are the larger issues at play? What is the right balance between socializing and privatizing liability? How much of a moral hazard, if any, do we create, if we move away from imposing liability on the party responsible for a loss? In making these decisions is it necessary to distinguish between different types of liabilities, such as ordinary negligence, recklessness, product defects, and/or deficiencies in the delivery of adequate levels of service? How do we factor in the physical risk environment? Should there be geographically differentiated rates for customers reflecting the physical environment in which they are located? How should policy makers and regulators balance between safety and reliability in terms of what is expected from regulated utilities? Does the scale of the liability impact the decision on who should bear the risk of loss?

Moderator.
This panel this morning is on utility liability, particularly focusing on major natural events. I don’t think, as we sit here in a beautiful hotel in the service territory of the Pacific Gas and Electric Company, that I have to tell you why this might be relevant. Things are interesting these days, and we have just an outstanding panel.

Speaker 1.
When we discussed doing this topic, it appealed to me, because, actually, before I became utilities commissioner, one of my areas of law practice was insurance reform, that is, suing insurance companies for how they did business. The reason I ended up as the public utilities commissioner is because I was in line to be the insurance commissioner, and the insurance industry thought I’d make a wonderful utility regulator.

So, let me start off with just a couple sort of fundamental regulatory principles and the balance that regulators have to strike when looking at these liability issues. One is, of course, cost containment and accountability, and trying to balance those two things. You want utilities to be accountable for what they do, but you don’t want to spend more money than you need to, and you try to develop a balance between those two things. And then you also need to think about the appropriate risk allocation from the liability issues.

I’m going to divide liability issues into two categories. What ought to be privatized, what ought to be socialized, and what’s the balance between those two, and how do you view that in the context of regulating the terms? It’s one thing to do it in a company that operates in a competitive market that isn’t constrained by a lot of rate of return regulations. When you’ve got that, you change the equilibrium a bit, and it needs to be thought of.

What are some of the specific things that regulators need to think about balancing? Obviously, one is cost. Another is what I just referenced, which is the degree of risk taking, which needs to be proportionate to the potential for returns. Another is incentives. When I was on the Ohio commission, we had two PhD anthropologists who literally wrote their dissertations on utility culture. And we used to talk to them all the time about how what we were doing would be received in the utility culture of the company we were regulating, which is kind of an interesting exercise. But think about the incentives and what the impact of the incentives is. Another issue that’s critical is moral hazard. You don’t want to relieve people of responsibility for the things which they do, and so you need to create incentives for them that don't create a kind of moral hazard. And then you need to view risk and distinguish between what's controllable and what's not controllable, or, probably more accurately stated, you need to assess to what degree things are controllable and to what degree they are not controllable, because they should get different kinds of treatment.

And then the last question that I'm posing is, what are the appropriate risk mitigation efforts that should be undertaken? Whether it's purchasing insurance, whether it's training people, particularly related to safety and public health, what's prudent, what's cost effective, and those kinds of appropriate risk mitigation issues.

But there are two contexts, when you think about utility liability, that I want to talk about. The first is the context of tariff services, and the second, which is what you have in California now, is outside the context of tariff services, torts being an example, but there are others as well. And so those are the sorts of things that need to be thought through.

Now, in regard to tariff services, there's always been a tension. Utilities, to the extent they can, obviously have a self-interest in trying to limit liability through their tariffs, because then they're contractually limiting what liability they might have to their customers. And obviously, from the perspective of consumer advocates, they don't want that. They want the utilities to be exposed, to the extent that customers can get the relief they think they should be entitled to. Now those limits most commonly are found in tariffs; sometimes they're found in statutes, sometimes they're in the rules, and there was always a tension between what limits, if any, you put in the tariffs, and what limits you don't put in the tariffs, or, put in different terms, what's in the scope of jurisdiction of the courts and what's in the regulatory jurisdiction. State laws vary about who does what. In some states, the regulator can make decisions, but has no ability to enforce them, and that has to go to the courts. In other states, regulators have more enforcement capability. It's all over the place.

But the issues that typically come up are, for example, if you have service outages, what are the consequential damages, and who is liable for them, if anybody? Is the utility responsible if you lose everything in your refrigerator? Does the utility have to compensate you? Do you put that in the tariff, or do you leave that to the courts? These are the kinds of decisions that regulators have to be making all the time.

And then, also, you go to the question of, do you look at causation? Was this a storm that caused these outages? Was it something else – was it utility malpractice, for lack of a better term - that caused it? How do you evaluate those things? As I said, oftentimes the regulator's discretion is constrained. First, by statute, but, second, through who actually does the enforcement, and also by the level of judicial review.

The other piece that also relates to this is the question of the extent to which the regulators use normalized rate making. What does that mean? That means you anticipate certain levels of risk in the rates. Some years utilities don't incur those risks, and they make money on it, and other years they lose money, but, generally, regulators don't adjust rates to reflect that, because it's assumed that over the long term it balances out. It always becomes an issue, because consumer advocates almost always will argue that, you know, if the utilities didn't incur those risks, why are we paying them for it? The flip side is that utilities, when they do incur those risks, are complaining that they're losing money. And so, the question is, what are the boundaries of normalized rate making, and do you use it at all?

Now, if you're looking at determining liability (and this would be the regulator within tariff services doing this), number one, is the regulator empowered to make the decision, and does it choose to make that decision, or does it simply defer to the courts? Some of the questions you'd want to ask are, was the risk controllable? That seems to be a simple question, conceptually. Factually, it's not so simple. For example, this had nothing to do with regulators, but the classic case was after Katrina hit, and Entergy had all this massive damage, and they wanted FEMA to reimburse them to repair the transmission lines. The Bush Administration's position was, "You didn't buy insurance, it's your problem." So, even though they couldn't control the storm, there were measures they could have taken to mitigate the risk. In that case, it wasn't the regulator, it was FEMA that made that decision. It actually was the administration that made the decision. So, on the question of, was the risk controllable, you have to look at that in all of its nuances. Were there reasonable risk management measures undertaken, and what are the consequences of the deficiency? So, if, for example, you decide the utility is liable, what are they liable for? Is it penalties? Is it consequential damages? Is it simply an order to fix the problem? Or, in the case of the nuclear plant that we had in Ohio, we could simply suspend the payment of dividends, which we did on a couple of occasions where we saw a pattern of problems. But what are the appropriate consequences of a failure to do it?

Now, part of what you look at is the nature of the deficiencies. If it's a singular episode, then you're not likely to look at that very severely. On the other hand, if it's episodic, and certainly if it's systemic, then that becomes a major problem. And then, if you do award some kind of consequential damages, or you enable the courts to provide that, then the question becomes, how what's the rate treatment for any of those damages or penalties? The regulatory policy there is actually fairly clear. If the utility did something to cause the problem, there is no recovery to be allowed, because that's their problem, and the idea is the moral hazard. Now, at some point, the consequences may be so enormous that you have to think about it, although that's more likely to happen outside of tariff services than within them. That's the California situation. Then you have to rethink exactly what you want to do, and what the consequences are, but the principle is fairly simple. If, due to negligence or bad behavior or whatever, you are considered responsible for this problem, generally, rate payers don't pay for that.

Doing all of this in the context of maintaining the equilibrium between the risk and return, let me turn to non-tariff issues. Those are beyond the scope of what the regulator can do. It's either defined by statute or by common law, and, obviously, all adjudications here occur in the courts, as opposed to occurring in the regulatory body, although the regulators can't help but be involved at one level or another.

So, what is the regulatory role when you're looking at those kinds of things? Well, what's the degree of regulatory oversight one has? For example, if you have a utility that has a pattern of simply not maintaining its equipment, at what point, if any, should a regulator step in and force that to happen? We actually had an example of this in Ohio when I first came on the Commission. There was a utility which, every year, had so much in their budget and in their rates to be approved for tree-trimming and line maintenance and, invariably, they didn't spend a nickel of it and pocketed the money. Fortunately, that never became a safety issue, but it became an enormous issue on quality of service. And so in that case we had sort of an extraordinary mechanism in which we simply had them turn the money that was allocated for that over to us, and when they produced proof they had done the work, we reimbursed them. That's an extraordinary level of regulatory oversight that you wouldn't ordinarily engage in, but, at some point, regulators may want to think about taking those steps. That could have been a safety issue. Fortunately, nobody ever got hurt as a result of that.

Another role for regulators is identifying what risks really are internalized in the rates and which risks aren't and determining whether you want to adjust rates to reflect certain risks. The classic example here would be a risk where there wasn't much the utility could have done about it; for example, "strict liability" issues. There is *something* they could have done – you're never in a never situation – but what's internalized in the rates and what's not? You need to identify the risks that are capable of being internalized and which ones aren't.

Then you also need to develop the mechanism for the appropriate treatment. In the example I just gave, there is direct regulatory supervision, performance monitoring or, in some cases, almost substituting management judgement. That's an extreme sort of step, but there may be circumstances where that's justified. Another option is explicit orders or rules for performance - kind of like injunctive relief from the regulatory agency saying, "Look, here's the pattern of problems we see. This is what we expect to happen." And that often comes out of management audits that are conducted to review utility activities in certain areas where problems are suspected. And then, of course, the example I gave is for the option regulatory controls over expenditures for designated activities. That could be budget oversight. It could be escrow funds, as in the example I gave.

There are many reasons why regulators may be reluctant to take those kinds of drastic steps. One of them is that at some point, you may be inadvertently shifting the risk from the utility to the state, if the regulator is assuming certain functions. And that should make regulators very cautious about how they intervene and then what exactly they do.

One of the other things, obviously, regulators need to do is advising policy makers on risk allocation. Of course, I'm talking about legislators. Now, all of us know that no legislator needs advice, because they're all experts in all the subjects that they deal with, and they always make wise decisions and they're never unduly influenced by any economically-motivated parties. That just doesn't happen. But regulators are in a position where they can provide non-financially interested expert advice to policy makers, who may or may not follow it, but at least that kind of thing can be available. In essence, as a regular I'm kind of lobbying, but not lobbying for particular interests, but from the standpoint of the expertise that the agency has.

And then, obviously, what regulators are going to do for any liability outside the scope of tariff services is determining what is recoverable through rates. And the factors you'd have to look at are prudence, what mitigation measures were taken or not taken, the controllability of losses, you know, *force majeure*, you know, being something that's totally beyond control…to be honest about it, I don't think there's anything completely beyond control. You can't control storms, but you can control whether you mitigated the damages through insurance or through other kinds of things. There's always some element of control, but trying to find the balance of that…and then, obviously, there's the moral hazard question. You can't simply pass on all costs to consumers without thinking about the question, are we creating a situation where the actor, in this case the utility, has no real consequences from adverse actions that he takes, from reckless driving of a utility truck to hypothetically starting forest fires. I mean, the moral hazard needs to be taken into account, and also, I think regulators are going to have to look at the standard, thinking about negligence and recklessness. Obviously, negligence is one thing. Recklessness is going to lead to higher damages and also is more blameworthy. And then you've got strict liability. It's very fact-specific whether the utility actually did something, or it's just a matter of their status. And, of course, politically, it's obvious utilities are deep pockets, so, if you're a plaintiff's lawyer, principle number one is, you go after deep pockets, and utilities are there. And also, obviously, if you're going to look at rate adjustments, there's the question, were these rates normalized, or were they not normalized?

Now, in specific regard to catastrophic losses…I mentioned nuclear accidents, but that's limited by Price Anderson. However, there's large scale environmental damage. Obviously, conflagrations are an example. You see that in California. How do the regulators respond to that? Do they try to adjust rates to help the utilities avoid what could be the potential for bankruptcy, or do they simply say, this is beyond what we can do anything about within the rates, or maybe as a matter of policy we shouldn't, and simply allow this to go into bankruptcy? The concerns there are obvious, and they've been talked about for a long time: the loss of control over rates and service issues, the ability of the utility to attract capital and maintain its supply chain and insurance, utility capital structure going forward, and the costs to the consumers, with or without bankruptcy. So, bankruptcy is a fear factor. You never know what kind of bankruptcy judge you will have. In this case in California, ironically, the judge that's hearing the PG&E bankruptcy, this is déjà vu for him because he heard the previous PG&E bankruptcy. It's his life's work, right, dealing with PG&E bankruptcy, although we heard yesterday that the utilities never go bankrupt…

So, what are the broad policy implications? One is assigning risk based on causation. So, if the utilities, like any other party, actually were the causes of a problem, then in legal theory, and just in a matter of fairness, they should be assigned the cost of dealing with it. However, there are consequences depending on how you deal with it, and there are a lot of nuances about how exactly you evaluate that. You clearly want to avoid moral hazards. If you're going to be in the marketplace doing things, then people need to have the incentive to behave appropriately. Avoiding risk assignment based on status. This is the "deep pocket." You look around, the utility's got a lot of money, you go after the utility. It's sort of one of the principles of carbon reduction, right? Go after the electric sector first. Don't worry about transportation, because utilities are easy targets. Appropriate risk allocation: what ought to be privatized, what socialized, how do you avoid getting those two things confused or creating perverse incentives? Appropriate incentives – actually more than incentives – sometimes oversight to assure prudence and intelligent risk management of risk. Then, finally, to try to keep all of this in mind in the context of the fact that utilities are operating under rate of return regulations, so the upside for them is limited, so they're not like another actor in the marketplace, and may merit somewhat different treatment. So, at that point, I'll conclude. Thank you.

Clarifying question: I'm wondering, in the context of rate of return regulation, where penalizing utilities from a liability standpoint in their rate of return hits into those considerations?

Speaker 1: That's a good question. It inevitably does, because one of the things you look at in rate of return is, what does a reasonable investor need to have in order to be willing to invest in the company? So, all of this affects the rate. How the companies perform with potential liabilities will obviously affect the rate of return, and that's something the regulator has to keep in mind. What's optimal to be the rate of return? And the more risk you put on the utility, then, at least in economic theory, the more you've got to raise the rate of return to reflect that, so it can attract capital. So that is part of the balance the regulators have to think about.

Speaker 2.

Thanks. Well, Ashley invited me to come here and present the plaintiff's perspective, and I've been to enough of these conferences to know this is a little bit like taking a suicidal leap into a den of lions, but I asked him where this was, and he said, "San Francisco," so I said, "I'm game." [LAUGHTER] I'll try to do my best.

I teach torts, so I'm coming at this from the perspective of a torts teacher who might have a more global view, but I'll try to channel the plaintiff's perspective as well. I just want to begin with some data on risk that many of you have probably seen before. This is some data from a survey of economic leaders throughout the world. It's presented in a risk quadrant format, showing that the highest impact/highest likelihood events that world economic leaders foresee as coming up in the next 10 years are really focused in the environmental area. I know it's hard to read this diagram but, as you can see, they're climate-related risks, weather-related risks, environment-related risks, and they tend to be high likelihood/ high impact, according to the survey respondents.

If we think about what utility regulation has traditionally done, it's focused on more economic risks: risk of inflation, risk of interest rate changes, risk related to fuel prices and the like, and those are clustered in the quadrant for lower impact/lower likelihood events. So, these are just very different kinds of risks that we're looking at, going forward, in the world economy, and if we think about the utility sector, we see evidence that these risks are beginning to materialize here in the US. If you look at actual events that have occurred in the US, in 2017, we had 16 one billion-dollar plus events in the US that would fit within this upper category of the risk quadrant, in terms of being high impact. We had 14 one-billion-dollar plus events in 2018 – I believe they're still counting, because the damages are continuing to pile on. And the magnitude of the losses for each of these events is even more striking. The average loss is around five million dollars per event, and some of the events are much higher, of course. And, in the US, if we just think about these weather- and climate-related economic losses, about half of them seem to be insured, and the remaining losses represent what the insurance industry might call the "coverage gap." These have to be picked up somewhere, either absorbed by the victims or by the government, and part of what tort law does is, of course, shift the loss from the victim to the court fees.

In this context, I'm focused on the utility industry. So, what I tried to do initially is just think through the kinds of claims that utilities might face. This is my very rough typology of these claims, divided into four types, and further sorted by incident and cause(s) of action. As Speaker 1 mentioned, the private kinds of plaintiff claims that we see are typically customer and noncustomer claims. The examples that Speaker 1 talked about at length are the utility shut-off claims, which can be negligence or contract claims, often controlled by tariffs, but there are also other customer claims involving power surges – maybe the child of a customer who is electrocuted due to a piece of equipment owned by the utility. There are equipment failure claims that can involve customers or noncustomers. There are also pollution claims. If we think about the weather- and climate-related risks, increasingly there are claims, such as wildfire claims like we see in California, flood claims, and we could have claims involving things like coal ash spills and the like related to utility operations. As you move on down this typology, there are other kinds of claims as well. In the PG&E bankruptcy, a lot of the plaintiff claimants are insurance companies, and these are subrogation claims that are being brought. I'm not going to talk about those, but it's important to keep in mind that those are lurking in the background as well. And then there are claims where governments are the plaintiffs. These are the public nuisance claims.

I just want to use this typology to try to focus my comments. I'm going to focus mostly on the customer and noncustomer kinds of claims that Speaker 1 referred to, though I just want to highlight that the scope of this category is much broader than just shutting off service; these claims involve lots of other things, including environmental risks, pollution risks, equipment failure, power surges, and the like. So, thinking about this from the perspective of tort law, what are the aims, what are the purposes we're trying to accomplish through the tort system? They're really twofold. First, plaintiffs are seeking compensation, sometimes called "redress for harms," that they've suffered. Typically, these are physical injury harms or property damage, but sometimes they're economic loss or emotional harms. These are a form of redress in that they're attributed to the defendant's wrongful acts. Often they're negligent acts, but not always, as Speaker 1 mentioned; they can be strict liability torts, in many instances. By nature, this compensatory function, which we often call the "insurance function" of tort law, by nature it's backward-looking, in terms of both the injury and the wrongs. So, after the wrongs occurred, after the injuries occurred, we have a trial, and we look back and try to do our best at achieving redress and achieving compensation. And modern tort law is able to achieve this, even for injuries that are pretty widely dispersed and that historically wouldn't have been covered by tort law, because plaintiffs wouldn't have had incentives to bring suit. Today, these kinds of claims are brought as class actions, and they often lead to structured settlements that allow plaintiffs to achieve compensation.

A second goal of tort law that plaintiffs also care about is deterrence of future accidents. In other words, what kinds of investments can be made to reduce risks or mitigate risks of harm in the future? This is more forward-looking, or more regulatory, in nature. Right? It's not as backward-looking as compensation is. Tort law tries to ensure this goal by placing liability with what we frequently call the "cheapest cost avoider," which is the party who is not just able to control the risks (I think it's recognized that both parties sometimes will have a degree of control over the risks), but which one is really the most efficient party to be bearing the costs associated with the accident and to take precautions in the future to reduce the risk.

Now, often, promoting deterrence through the tort system is consistent with achieving compensation or insurance, and, when that happens, the tort system might be said to be working well, but often there's a tension. Speaker 1 referred to this. The classic example is moral hazard. Think of the smoker with health insurance who just won't quit smoking, because they have health insurance. That's all mentioned later in my presentation. I think, in the context of utility regulation, this moral hazard question is not an easy one; it's a very complicated one. Now, there are some analogs within utility regulation that parallel the goals of tort regulation. So, I think there's an opportunity here for some synergy between the tort system and utility regulation.

First of all, the compensatory role, or the compensation role, as Speaker 1 referred to it. It's quite possible for utility regulators, through the setting of rates, to pool risks and socialize costs and spread them among the customer base. And, if you think about the whole purpose of utility regulation and some of its history, arguably, this was achieved with respect to customer reliability from the beginning. Right? If you think about things like the duty to serve, this might be thought of as a form of embedded insurance against service shut-off, through the utility's infrastructure investments and through the kinds of compensation it agrees to provide if service is discontinued for certain customers. So, this is an embedded form of insurance that utility regulation has a long history of dealing with. We rely on customer cross subsidies as a form of insurance, of sorts, in this context, but, more generally, outside of these kinds of customer shut-off issues involving the duty to serve, regulators generally don't directly dispense compensation to customers for the kinds of harms they suffer due to wrong doing. So, the insurance function is pretty limited. It's only self-executing for certain forms of harm to customers, like maybe refunds for wrongful service disruption or other things that are outlined in tariffs.

More generally, I think we need to look to other mechanisms for covering losses. Some losses are commercially insured, and insurance, of course, can be expensed by the utility, which has tax advantages and other regulatory advantages.

Beyond this, there may be liability expenses associated with noninsured losses that utilities incur through law suits or settlements. I think this last issue is perhaps the most difficult. The problem with the last issue, of course, is that, with utility-centered compensation that occurs outside of insurance, through liability expenses and the like, it's not always clear, *ex-ante*, which losses can be recovered from customers, and if you have a prospect of large scale risks and harms, I think, particularly risks and harms to noncustomers, there's a need for much clearer *ex-ante* standards for trying to determine when liability expenses will be recoverable and when they will not be. I think Speaker 1 was alluding to some of these issues, and the San Diego Gas and Electric Company case here in California stands out as an example where you had a massive settlement by the utility of claims related to wildfire. And with 20/20 hindsight, regulators stepped in and applied a "prudent manager" standard and rejected the utility's request for cost recovery.

Utility regulation also has some analogs in terms of deterrence. On good days, utility regulation can promote investments in infrastructure that achieve desirable public purposes and also protect consumers, but often, I think, utility regulation is pretty weak in anticipating and pricing safety and environmental harms. This is in part because of the history of what utility regulators do. They're focused primarily on economic issues, such as consumer protection and competition policy, but they're not necessarily focused on internalizing costs that are nonmarket costs that go outside of the asset price or the cost of service for actually investing in the infrastructure to provide service to the customers. Utility regulation is poor on a variety of different fronts in this regard, I would argue. It underproduces information about the safety and harms associated with different infrastructure investments. Tort law can produce transformative social facts about risks and harms. There are many examples: tobacco litigation, etc., etc., that we could look to. Utility regulation, of course, focuses on the costs of infrastructure, but it often produces little or no forward-looking assessment of risks, especially the risks to safety associated with infrastructure, and potential harms that might ensue down the road, including generations into the future. Torts can encourage both regulators and private utilities to perform more comprehensive risk assessments and to perform them more frequently and update them more frequently. This would reduce regulatory lag in the assessment of risk in the utility regulation process, and it would encourage the use of more sophisticated modeling, scenario evaluation, etc., in evaluating different forms of risks. Tort law can also serve as a check on the investment biases that utility regulation might encourage. We all know about traditional biases, such as gold-plating. There are many examples of how utility regulation, itself, produces moral hazards in investments. It might encourage overinvestment in certain forms of insurance at the expense of forward-looking risk mitigation or investment in infrastructure that produces benefits decades into the future, because a utility regulation might apply the wrong discount rate to these future benefits and underinvest in these long-term infrastructure projects. And torts can also serve as a check on corporate complacency regrading risks and help identify, for example, who are the Volkswagens of the utility industry. So, torts can serve as a safety supplement to utility regulation. I'm not arguing here that we second guess regulators' prudency determinations, but instead that we treat these as a floor, not a ceiling, for purposes of safety and environmental risks.

There's an opportunity here for tort law to serve that supplemental role in encouraging the utilities, themselves, to better incorporate risk assessment as a forward-looking matter, as they evaluate their various investment options. This can occur through strict liability or negligence. I won't talk in detail about these two particular kinds of claims, but I do want to move on to talk about some legal barriers that plaintiffs potentially face.

Speaker 1 alluded to one of the most significant barriers, and that is that most utilities, as they think about their liability related to customers in particular, they look to tariffs and what the tariffs say with respect to various forms of injury and various kinds of accidents. Effectively, through tariffs, utilities can contract around torts, and these serve as forms of releases from liability. In certain instances, they limit damages, and in other instances they might provide for even broader liability limits on utilities. A majority of states allow utilities to use tariffing to shed risk in this manner, although generally they're not allowed to do so for gross negligence or for willful or malicious torts. But, you know, we don't allow, for example, rental car companies to shift risk to customers for the defective brakes in the cars that they rent. Courts are much more skeptical about these kinds of agreements, and it's not surprising that, in many jurisdictions, courts have looked skeptically on these kinds of tariff limitations. They've construed them narrowly – that's the most common move you see – but also some states have started to question them on public policy grounds, much as courts in other contexts question assumption of the risk sorts of agreements in consumer contracts such as rental car agreements. In any event, whatever we have to say about these kinds of limitations with respect to customers, there's a serious question about whether they can limit claims by noncustomers, and if you go back to that torts rough typology I mentioned, as you move down the typology, more and more of the kinds of injuries and claims the plaintiffs are going to be bringing are noncustomer claims, not customer claims. These are the claims that are growing in significance. These are the kinds of claims that we're more likely to see with respect to risks like wildfire risks, pollution risks, flood risks, and the like. So, I think that we might need to be looking at some things other than tariffs as a way of thinking about the difficult liability issues.

There are some other barriers the plaintiffs face. Let me just briefly mention a couple of them. One is preemption and the "filed rate" doctrine.

Regardless of what a tariff says, the very fact that you have a filed rate that's approved by a regulator, that very fact might be said to have a preemptive effect. I've written about the filed rate doctrine elsewhere, and I'm very skeptical about filed rate doctrine defenses that serve as a blanket prohibition on tort claims as well as antitrust claims. But whatever we have to say about them as prohibitions on customer claims, again, with respect to noncustomer claims, I don't think we can say the filed rate doctrine has that same effect, because those noncustomer claims don't effectuate discounts or rebates on rates that would lead to customer discrimination. Another issue related to filed rate is whether there's broader preemption that might come into play here. I'm also somewhat skeptical about these preemption claims, because I think, absent express preemption…And there are instances where we have preemption. For example, there's preemption under Part One of the Federal Power Act, there's preemption with hydropower licensing, there's preempted state flood acts, there's the way the Nuclear Regulatory Commission preempts state safety regulation of nuclear plants and the like…Absent this kind of express preemption, or the existence of a comprehensive compensation scheme operated by the regulators, or a comprehensive regulator assessment of safety and determination regarding forward-looking deterrents, absent these kinds of things, I don't think it's likely we'd have broad preemption of these kinds of tort claims.

Another thing many state courts have done with respect to the management of plaintiff tort claim, negligence claims in particular, is that these claims have sometimes been rejected for lack of duty. A very interesting case that came out of the 1977 blackout in New York involved Con Ed management. As you might recall, Con Ed was found to be grossly negligent for the events that led to that blackout. There were many, many different claims that were brought, but one of the claims led to a decision by the New York Court of Appeals on this issue, where the New York Court of Appeals found no duty was owed by Con Ed to a customer who was injured, not while in his apartment but while in the common area of the apartment complex in which he lived. So, the Court here imposed a duty limitation. As soon as you cross that threshold into the common areas, as soon as you step into the dark stairway going to the basement of the apartment complex or something like that, you're no longer owed a duty by Con Ed with respect to service shut-off in that case - a very interesting case. The Court there relied on some traditional ideas regarding duty, such as whether or not there was a special relationship between the utility and that person who was injured. It found no special relationship in the place in which he was injured. It also relied on broad discussions of foreseeability and public policy and a concern here that too broad liability here could push the utility into fiscal distress. So that's a very interesting idea that I think we might see invoked as a potential limit on claims, increasingly, if the number and severity of these claims continues to grow.

Many states have also recognized limitations on duties owed for certain kinds of injury. In California, there's a pending case involving the economic loss rule suggesting that to recover for economic harm, there's a duty limitation on negligence unless you have some physical injury to property or to person to accompany that economic loss, and, similarly, there are limitations on duty for recovery of emotional distress. All this said, the trend, increasingly, that you see among plaintiffs' lawyers is to push for broad recognition of duty and to allow broad recovery, and, in some states, you can even get recovery for medical monitoring costs, as I've mentioned here.

I was going to say a few words about alternative compensation schemes. I just want to mention the idea that Speaker 1 touched on, and that's the use of reserves for risk-specific categories of harm, similar to Florida's hurricane reserve funds. What I've learned about these in Florida is that they have reduced borrowing costs for catastrophic bonds, and they also encourage utilities and regulators to have some skin in the risk assessment game on a more forward-looking basis.

To conclude with just a couple of thoughts, moral hazard is a tough issue here. It's a common issue to raise, but I think it might be misplaced to focus on moral hazard solely as a plaintiff versus defendant issue without also looking carefully at how the regulatory process can create certain incentives and disincentives and has certain biases that might produce their own forms of moral hazard, and specifically that might encourage overinvestment in certain kinds of insurance – commercially available insurance – at the expense of forward-looking risk mitigation measures. I'll just conclude with that thought, and I'm happy to answer any questions and discuss more during Q&A.

Clarifying question 1: I'm wondering if you have done any research, or if you know of any cases when we can square the obligation to serve or the duty to serve with insurance availability? There are some instances where the risk is too expensive, too hard to mitigate down to a reasonable level, and yet the utility is obligated to serve a customer, and it creates this hazard that is just too big to mitigate against. How does the regulator handle those situations? (And, by the way, that's not so hypothetical in California anymore.)

Respondent 1: I haven't done any research on that question. One way of thinking about this is in terms of the premium we all pay in rates that provides for a form of embedded insurance that the utility provides by socializing the cost.

Respondent 2: If I could just add something in response to that. One of the things that regulators are going to have to assess is what risk mitigation measures were actually in place. It may well be there weren't any. That's entirely possible, but I think regulators, if they're doing their job, particularly in the case of catastrophic losses, ought to be looking at the question, did you really do what you need to do to search that out?

Questioner: I completely agree. I think the question that I have is even one step removed. Are there instances where the obligation to serve is not absolute, because the risks are just so high that there is no standard that is appropriate?

Clarifying Question 2: When you use the term "moral hazard" in the context of socialized risk, do you have creditable information about the impact of Price Anderson?

Respondent 1: I think Price Anderson is an interesting thing to think about in this context. As I understand it, Price Anderson was directed at maybe a different kind of risk problem. We're talking here about a catastrophic nuclear event, you know, the predictability of maybe a single catastrophic event, and the massive costs associated with that, which couldn't be borne by any single utility, so we had to come up with this mechanism to try to spread some of those costs in a trans-utility manner. And that aspect of Price Anderson makes some sense to me. It was coupled with a couple of other things that, you know, come as part of a comprehensive federal initiative, along with industry-led initiatives to regulate safety in the nuclear industry on a forward-looking basis. And it also has been widely criticized as a massive government bail-out of the industry, because there were caps on the utilities' obligations. I don't know those precise numeric caps. Many of you probably do. However, there are also caps on the cross-utility fund, as I understand it, and then the government steps in and picks things up after that. And then I think there's a limit on the government cap, but then the government can come back and decide to use more to clean up whatever catastrophe we have related to nuclear. That aspect of it has been widely criticized, and maybe there are other ways of approaching this that are trans-utility. I like that feature of Price Anderson.

Speaker 3.
Good morning everyone. As we move into this next part of the panel, you're going to hear a good bit from me, and then from Speaker 4, about the specific situation here in California, but before we go into that in a lot of detail, I do want to say to y'all who are not from California, as I am not, that I think there are a lot of lessons here that are applicable to the rest of us. As Speaker 2 mentioned, we're seeing an extraordinary increase in the number of billion-dollar plus disaster events. Those events are going to challenge the utility industry around the nation; this is not just going to be a wildfire problem. And when that happens, as Speaker 1 pointed out, utilities are often the deep pockets in the room.

And so, what I want to talk about a little bit today are some of the dynamics around disasters and disaster relief and the risks that they might pose to the industry at large, and I will talk a little bit about the California situation.

There are three big points I want to make today. The first is that utilities do have financial incentives to mitigate risk, and I think that one of our design problems is thinking about how those incentives play out, and how investor response to those incentives, or utilities' abilities to raise capital, feature into what we want to do to create risk mitigation programs. Second, we've already heard a lot of talk about moral hazard; it was in the framing of the panel. I think that when you're talking about natural disaster events, the focus on the question of utility moral hazard is far too narrow. There are a number of other players who are also exposed to moral hazards, and if you're thinking about how you want to design a system to efficiently address those risks and to compensate people when they face losses, we need to talk a little bit about some of the other players in that system who face moral hazards, so I'll touch on that. And then, finally, I want to talk a little bit about the concept of social license to operate, which is a concept that's originally drawn from the mining literature, but is very popular now in the concept of ESG (Environment, Social, and Governance) investing, and how companies engage with the world and with their shareholders. I think that it's an important concept here, because, as we start to think about tuning incentives for utilities, since utilities are territory-based businesses, and they can't pack up their toys and leave, I think there are some reasons to think that the use of social license to operate may mean that we don't have to worry quite as much about perfectly tuning those incentives around moral hazards.

So, on the first point, around financial incentives to mitigate risks, as you all know, when you are a transmission and distribution utility, the way that you make money is by operating your system efficiently. Right? You have your regulated rate of return and, if you have problems in how you operate your system, you're not going to be able to make money. That's something investors are pretty savvy about, so there is a good amount of pressure to operate efficiently. I think there are some interesting questions that, I suspect, Speaker 4 will go into a bit more, about what those incentives for efficient operation mean, and whether the markets are really savvy enough to understand things like safety culture from afar. That's not the kind of thing that you can necessarily get from reading a 10-K.

There are a lot of investments that are being made in hazard mitigation right now. If anyone's not familiar with it, I would commend you to SDG&E's page on Fire Hazard Risk Mitigation. They have the incredible systems in place. They have 117 weather stations, and they get real-time updates every 10 minutes, so they're able to actively monitor the conditions in their service territory, and so they can take actions to mitigate wildfire risks. That's really awesome, and I absolutely commend them for doing it. That's not necessarily a transferrable model, when you go to other parts of the country where the service territories are more geographically dispersed. I think it's a great program. I'm glad they do it. I have some questions about how you would take that kind of investment and risk mitigation and do something that is appropriate and scalable, for example, if you are in a more rural service territory – somewhere like Montana - where you may have the same kinds of wildfire risks, but your network is much more dispersed.

The other big risk mitigation measure that is newer here in California – and many of you will be familiar with it – is a public service power shut-off. So, utilities in California now have the ability to shut off lines and de-energize to minimize wildfire risks when conditions are right for that.

I want to pause here for just a moment to talk a little bit about social perceptions of risk and how people react to power shut-offs, because there's a really important contrast here, I think, between shutting off power to prevent a wildfire and shutting off power in other regions of the country for natural hazard risk. When you do a public service power shut-off, if you do it at the right time, there is no fire. And then you have a whole bunch of people who are really cranky that you shut off their power, because they didn't experience the fire, so, to them, there was no problem. If you look, in contrast, at what happened when hurricane Michael hit Florida last year, Duke engaged in a really extensive de-energization in their service territory, which minimized damages in that area and allowed them to get the grid back up and running much more quickly afterward, and Duke was a hero in that narrative. Right? It was the same action taken but, because of the way the people perceive risks, and because Michael came through and flattened a town, people could understand how Duke's actions had helped to minimize risk, and they were sort of the hero in that story. It's much more tricky when you're dealing with avoided risk, because people are really, really bad, intellectually, at understanding avoided risks.

I'm going to talk a little bit about the specific liability construct in California, because it's something the markets have taken note of, and I think it is just important to sort of lay it out for this conversation. So, here in California, the Doctrine of Inverse Condemnation can apply to utilities, and here's how this works. This is not a constitutional provision in California – inverse is constitutional as it applies to true government entities, but the application to utilities is case law. There is a decision out of the California Appellate Court, and essentially what happened in this decision was that the Court found that, if someone lost their property due to the provision of a public service, in this case electricity, they should be compensated for that. They said, "You know, that looks a lot like an action of a governmental body and a taking." I actually think that the underlying *Varum* decision is quite elegant in its theory, because, essentially, what you would do, if this all worked the way the *Varum* court thought it would, is that you would take losses caused by the utility, and you'd spread them over the service territory. So, it's kind of like an average reciprocity advantage concept from regulatory economics. Right? The people who are benefiting from the utility service are also going to help the utility to bear the costs of accidents that happen along the way. Where this has gotten a little bit gummed up in the works, as Speaker 2 mentioned, is with the SDG&E proceeding. And essentially what happens in California is that the CPUC engages in a post-hoc review of prudency. So, when you have wildfire losses, you can put them into, essentially, an account, and then you can go in and try to get rate recovery on them. And I think the real challenge with the prudency review that's happening after the fact is that it's essentially converting a prudent operator standard into something that looks more like a perfection standard or a negligence *per se* kind of standard, and so I think one of the policy questions that we've been grappling with a lot is, what kinds of things could you lay out before the disaster happens? So, you could say something like, "Here's my checklist that shows that I've been prudent. Here are my vegetation management procedures, and here's everything I have to prove that I have engaged in that veg management, or I have done undergrounding," or whatever the other measures might be. Because right now, really, the prudent operator would take actions to avoid fire, and if you've caused a fire, you just kind of look like you weren't prudent, even if you were, because there are no standards against which to measure that prudent behavior, other than the presence or absence of the fire.

This is something, as I mentioned, the markets do care a lot about. Moody's has downgraded a whole bunch of California utilities and, in doing so, they have very specifically noted the liability regime and said that they may engage in further downgrades if there are not changes made here. So, on March 5th, the Edison International, SCE, and SDG&E were all downgraded, and the Trinity Public Utility District was also downgraded, and two other POUs, Burbank and Glendale, were placed on a negative outlook, all due to wildfire exposure. And so, this is somewhere where, as Speaker 1 mentioned, if you don't get these incentives right, it's going to be very hard to attract capital from the markets. And I think we have seen a bit of contagion from PG&E that is making it really, really hard for utilities to raise money, and so then, as you start to think about all of the kinds of sophisticated constructs that might be out there to create pools of capital so that you can compensate people when these losses happen, or try to mitigate further risks, it's really, really hard to raise that money right now.

I'm going to switch gears just a little bit. I want to talk about the paradigm that we have around socializing natural hazards like this. So, generally, in the United States, we have a cultural expectation that when people suffer a natural disaster harm, we compensate them. In lots of other parts of the world, people think this is crazy, but it is our political reality here, so, generally, if a property owner –

Moderator: Unless you're in Puerto Rico..

Speaker 3: That's right. [LAUGHTER] But, you know, generally, here we have a constellation of programs. We have hazard insurance, we have national flood insurance, we have a number of programs where, if a homeowner loses their home, we are making them whole. And we are typically doing that both by providing immediate emergency assistance, like temporary housing, and also by providing money for them to build right back where they lived before. One of the interesting things that you see is that in places where that coverage has not been enough, we have often seen states step in and provide even more coverage that provides more incentives for people to live in high hazard areas. So, an example of this is how a lot of the Gulf states do wind risk pooling, so, wind damage, which might be excluded from your regular policy, you can get coverage for it through the state. So, we have created a system where we are making areas that are exposed to natural hazards safe for people to live in. We're making it affordable for people to live there. And I think there's a really fundamental policy question of, why are we doing that, and do we want to continue doing it? But the fact is, we've gotten so good at it…There's a concept in the natural hazards literature now called the "safe development paradox," which essentially says, people will move to areas that have high natural hazard exposure, like right behind levees in Louisiana, because they just know that if enough of them move there, we're going to make it safe for them.

So, this brings me to my first moral hazard, which is state and local government. To the earlier questioner, I think you asked a really good question about whether there are areas that might just become too hazardous to serve, and I think, for me, one of the really interesting problems the utilities are facing on a going-forward basis is that you continue to have people move into hazard-exposed areas. Right in California, we've seen a huge growth in the number of people who live in the WUI, the Wildland-Urban Interface, and that's what causes some of the big losses from the wildfires. Right? People live where their trees start to burn, and it burns down their home. And when you look at how disaster relief functions in this country, I think what you see is that state and local governments have a lot of authority to control land use, so they're the ones making decisions about, things like, do we put more housing in because we have an affordable housing shortage? Do we allow people to build, because we're worried that we're going to get sued for taking if we say, "No, it's too hazardous for you to live there?" Do we want to expand our tax base? And, theoretically, if all the incentives were perfectly balanced, one of the things that would mitigate against that permissive development would be, "Gosh, we, or our community, are going to have to pay the costs to rebuild when the natural hazard strikes." But, as a matter of fact, a lot of those costs can be externalized onto the federal tax base, and so you're not getting the right incentives to slow development down in natural hazard areas. And I think that's particularly problematic for the utilities, because for as long as utilities choose to honor the universal service requirement, they're essentially going to see increases in their natural hazard exposure, because of the way the service territories will grow that they can't, themselves, control.

And so, I approach this conversation assuming that the natural hazard losses are going to get socialized somewhere, and I think the real question is, how are you going to do it? Are you going to socialize it across the rate payer base? Are you going to socialize it across the tax payer base? There were some examples of that. For example, in Florida after Hurricane Andrew, the property and casualty owners went to the state and they said, "We're just not going to write in your state anymore. It is too expensive, and you have regulated rates," (much like here in California), "so we can't charge more than a certain amount for insurance, and we just can't afford to be in the market." And the state said, "Okay, we're going to help you with this." And what they did was they created two things: they created a state-underwritten insurance company called Citizen, and they created the Florida Hurricane Catastrophe Fund, which is state-backed reinsurance, and they fund the hurricane catastrophe fund through charges on all insurance policies in the state, not just citizens, and through bonds. And there was a period of time in the mid-2000s when Florida had some really bad hurricanes when we were all watching Florida and waiting to see if Florida was going to have to ask for a letter of credit from the United States government, because the state got itself so exposed because it was trying to balance some of these other incentives.

I think the other important player to talk about here is insurance companies. So, in the PG&E bankruptcy claim, a very substantial proportion of the wildfire tort claims that are being adjudicated there are subrogated insurance claims. What does that mean? That means that the homeowners get paid by their insurance company, and then the insurance company steps into the shoes of the homeowner, and then they can bring the claim against the utility. Here in California right now, because of the way that the inverse condemnation scheme is working, functionally what that means is that we are asking the utility to act as the reinsurer of last resort. I personally think that's kind of a crazy thing to do, because the insurance industry is much more sophisticated in its ability to assess risks and to figure out how to address them. The insurance industry also has a much broader range of financial tools available to it than the utility industry does to do things like collect capital and invest it and make money on it and buy reinsurance and do some other things. I don't want to suggest that the utilities can't buy insurance or reinsurance, but they have much more ability to make productive use of capital and make sure that they have a big pool of money sitting around, so that if they need to pay claims, they have it. That's a really, really hard thing for utilities to do, both because it's not within the area of core expertise, and also because current utility regulations just make it really hard to sit on a giant pile of cash.

My last point, quickly. I did want to talk just a little bit about social license to operate. There is a lot of interest right now in the investor community around the idea that good environmental and safety performance is a proxy for good long-term financial performance of the company. There's a really interesting whitepaper by George Serafeim, out of Harvard Business School, that he did with Brookings, where they looked at the delta in long-term financial performance, and it is pretty substantial. So this is something that I think the markets are really excited about right now, and so we are starting to see a bit of a push for private governance that I think is another interesting factor to consider in how utilities engage in risk mitigation, and that will come both from investor pressures and also from the fact that the utilities live and work in their communities. And I would submit to you that one of the reasons that PG&E has had such a difficult time of late is because, after San Bruno, they didn't do as much as the community expected to sort of restore their relationship with the community, so then, when the wildfires happened, they were already perceived as a bad guy, and it's much easier to sort of want to stick it to the bad guy, [LAUGHTER] and I think that has been a part of their problem. And I will stop there so we have time to hear from Speaker 4.

Speaker 4.

Thanks for having me. I'm going to talk about a lot of these issues that we've been covering on the panel, and I am, to some degree, going to try to talk about what's already been covered, maybe with slightly different emphases, and also try to cover some new ground. I think that, as we think about the situation that confronts California utilities with respect to liability, and also to some degree other utilities (we saw, obviously the Columbia Gas issues in Massachusetts), there's an important issue to consider as to whether this is a legal problem or something else, and that is whether the problems that we're seeing with respect to financial distress in California really relate to the liability regime--the strict liability approach that's been taken by California courts—and, more generally, to how liabilities are socialized in California, or whether they're just a function of the scale of the liabilities. And I think this is a really important point that can often get lost in the conversation. I would argue that the scale is what matters, and that when utilities lose money at the scale of multiples of their net earnings in any year, this becomes a major problem.

The most familiar example of this kind of problem that we've all confronted is when nuclear power plants go wrong, and disallowance is associated with nuclear units and how that is worked out through the system. What is unique about the California situation is that, essentially, we're seeing a nuclear unit per utility burn maybe every year, maybe every couple of years. We're not really sure about the probability, but it's the scale that matters, and whatever framework we had for socializing costs *ex-ante*, whether it was a negligence framework or a reasonableness framework, as is possible under a different area of inverse condemnation law in California, or whether it was the strict liability regime that we have, the scale would break the system that we have. It is not a system that was designed to absorb 10 to 20 billion-dollar losses on an annual basis.

This scale that we have is an evolution from a system that was really designed to handle a different set of risks than it confronts today. And part of those risks have to do with operation and maintenance of the system, of the utility-operated distribution and transmission lines; part of those risks have to do with the pattern of housing development and land use that Speaker 3 just discussed in California, and the broader issues around where it is economic to build housing in California and where the legal and regulatory apparatus we have for controlling that allows new housing to be built; and part of it has to do with how people want to live, frankly. And, you know, if you look at the differences between what has happened in southern and northern California, part of the explanation is simply that in northern California people like to have pretty neighborhoods with lots of trees, and that can be very bad as the climate warms, and as the rainy season is delayed, as it has been for the last several years in California, into much later in the year, and so there's more time for fuels to dry out. In essence, there is a miscalibration of the physical and legal and financial instruments to the current environment that we face.

The system we have was designed to deal with 20th century risks, in terms of land use patterns, weather and climate, and utility operations, and we don't live in that world anymore in California. I would suggest that this may turn into a larger western US problem if, in fact, the trends we see in climate and in forest health continue to extend into the future. California, though, is unique because of its value at risk in real estate, and so, while Colorado and Washington and Oregon and Arizona definitely face this kind of exposure, it is not as severe, because thousand square foot tear-downs in Phoenix don't cost 1.5 million dollars, but they do in the inner bay area in the WUI, in the Wildland-Urban Interface.

I'd also suggest that, just as with the kind of dynamics that we see occurring when nuclear power plants go wrong, the liabilities that are occurring in these new contexts are large enough that the PUC is no longer the appropriate place to handle them, and I think an over-reliance on the delegation of authority from the state legislature to the Public Utility Commission to manage just and reasonable costs and safety and reliability, you know, sort of breaks down in a context where the liabilities overwhelm the economic regulatory apparatus that we've designed. You know, this is sort of like crisis times versus normal operation of the PUC. And, in particular, as we think about socialization of risk, it is appropriate to examine the kinds of options that are only possible if the legislature and the broader state government is involved. But, as we think about response to these problems and, in particular, the problem of wildfire in California, but, more generally, the problems associated with climate risks and environmental hazards for utilities, particularly with respect to noncustomers or noncustomer liabilities, I think the first step that utilities really need to take is to work the problem – work the risk management and physical mitigation problem –the physical risk reduction problem – because, frankly (and we're encountering this in spades in California as we think about options), what can be socialized and how it can be socialized depends critically on the magnitude of loss or liability and even more critically on the magnitude of expected future liability.

What are the cash flows that you need to secure in order to ensure against a future loss? It depends on what the future loss is going to be. If it's anything like the last two years in California, that's a lot of money. If the utilities can do something about it, then the problem becomes much more manageable, much more subject to normal utility commission processes, and potentially much more amenable to the provision of greater certainty to investors, which is going to reduce investment risks, cost of capital, and provide a really positive and virtuous cycle for everyone: rate payers, investors, the state.

As has been said previously on the panel by multiple people, quality is not something that PUCs regulate with particular effectiveness. My favorite kind of discussion of this is from Alfred Kahn's book on utility regulation, in the first chapter, where he just talks about the challenge of regulating for quality, understanding what is achievable in terms of innovation or service improvement as opposed to inspecting a lot of things. Commissions are good at inspecting; they're not particularly good at setting standards that look into the future and focus on improving quality.

Safety is definitely an important aspect of quality. A great book on this is by Demming, *Out of the Crisis*. Right? That's a sort of classic management book about minimizing variance in production, and one of the side effects of minimizing variance is safety. The most effective implementation of this modern risk management approach in the utility industry, I would argue, is INPO (the Institute of Nuclear Power Operations). INPO has, on the nuclear side, helped in a substantial way to ensure the safety of the units, and I think it's worth considering whether some INPO-like entity may be possible for western wildfires. A western wildfire INPO would create a set of outcomes, some of which are good or would be perceived to be good by certain stakeholders, and some of which would be perceived to be negative. One aspect of INPO that's really important is better information sharing--sharing across utilities of best practice, sharing across utilities of early warning signs of practices that may create risk. INPO, obviously, I think, in the view of the nuclear operators, has been enormously productivity-enhancing. Right? INPO is an important part of the reason that capacity factors in the nuclear fleet have gone from very low values to the exceptionally high values that they achieve today. So, potentially, there's a win there.

The downside of INPO is that it's far less transparent for external stakeholders. Right? INPO is not an open organization. That's by design, so that utilities can share with each other when they see a problem. An important aspect of the situation with wildfires today is that utilities feel very nervous, because of the liability regime, about sharing when there is a problem. A great example of this is the PG&E shut-off that occurred in October of last year. PG&E turned off the power in a public safety power shut-off, a PSPS, in late October, and blacked out about 60,000 people for 36 hours or so, and, in the process, prevented a conflagration. When they inspected the distribution circuits, there were 22 instances of conductors on the ground that, under the circumstances, if the lines had been hot, probably would have ignited wildfires and very dangerous conditions in exactly the place where the Napa and Sonoma fire siege occurred in 2017. That's a very successful outcome. It is not one that PG&E wanted to publicize in any way, because it's a sign of failure. Maybe a western wildfire INPO could start to share practices and outcomes in a way that could be safety-enhancing for all parties, and productivity-enhancing, especially if it avoids the creation of these gigantic liabilities. There's a lot of value creation opportunity there.

The challenge with INPO-like organizations is they require kind of a hostages-of-each-other dynamic. Right? It has to be a situation where the failure of any party in the system creates significant losses for all parties. I think that kind of a dynamic is developing in California, due to the credit risks and the credit perception of utilities in California. I think it really remains to be seen whether that spreads outside of California, but there's a possibility here of something productive developing. It remains to be seen.

Another question that's been raised by the panel is this question of obligation to serve and the balance between safety and reliability in exchange for just and reasonable risk. That's kind of the fundamental compact in utility regulatory sphere. One question that's being raised in California is, are different safety and reliability trade-offs appropriate, depending on the circumstances? Reliability is an unpriced good in the utility context. It is an unpriced value, and, you know, we just assume "one in 10" as a standard. Of course, what that means in different states, we know, is different, even across different utilities in the same state.

As we think about dipping a toe into this, you know, and exploring different safety-reliability trade-offs, one question to ask is, who decides? Right? Is it the utility that decides the safety-reliability trade-off? Is it the community? Is it the customer? And, in particular, how does adjustment occur for low-income customers? Rich folks have easy adjustment opportunities for these safety-reliability trade-offs. Right? If you're a California resident with a California IP address, and you go to SunRun or Tesla's website, all they're talking about is the PG&E power shut-offs, as they try to sell you a battery right now. But if you are a low-income person, good luck getting your power wall. And so, this raises interesting questions about what low-income affordability assistance should look like if the safety reliability trade-off changes, particularly in these wildfire-prone areas. So, I think, before we get to just how we socialize the cost, we really need to be thinking about working the problem, and possibly getting outside of the kind of typical utility paradigm. Right? Grid resilience, for example. We need to be thinking about customer resilience. That may mean different mixes of quality and safety. It may mean recognizing a locational value of safety, you know, as a trade-off against system optimization. Right? What's the locational value of a battery, if it allows PG&E to turn the power off and avoid a multi-billion-dollar liability? That's a lot of locational value, relative to, say, siting a battery in a load pocket where you mitigate a congestion issue.

The other thing that I think really implied by this is the need for partnership with others. Right? That is, the utility partner, to some degree, getting out of its foxhole and considering partnering with DER providers, considering different kinds of partnerships and arrangements with local governments, to enable the different operation of the system. And I think there's a tremendous value creation opportunity here, but it requires creative thinking and collaboration in a way that is not normal and is not limited to the PUC process.

The next question – socialization. What are we going to do? I would say, just at the start (and this has been mentioned), that the key thing here, as you go beyond the PUC, and even, frankly, within the PUC, is that trust matters. Nothing is more precious or more easily forfeited--more easily lost. And one of the challenges in these contexts of, you know, sort of *ex-post* questions around socialization, is that the very fact that the disaster that requires this conversation occurred has significantly eroded trust in the companies. Cost recovery certainty is hard to deliver when one doesn't trust that a company will do what it says it's going to do. And California has faced that challenge in spades and continues to face it. And so rebuilding trust in a partnership between utilities and their customers and their ratemakers is critical to getting this right.

I think the other thing to really think about are the distributional consequences of different approaches to socialization. Rate payers are one approach to socialization. Socializing across rate payers is essentially, at least for residential rate payers, like a flat tax. Right? The relative differences in consumption of electricity are small as compared to, for example, the relative differences in value between homes of low-income versus affluent people, or, in a more extreme case, the relative differences in income between different classes of tax payers. And so, socialization needs to be thought through, as we look at these catastrophic liabilities through a distributional lens. I think that's especially important in the current political moment.

Another question to consider is what the *ex-ante* conditions are. We are not designing a new approach to socialization of catastrophic utility liabilities in a sort of *tabula rasa* blank slate situation. In California, there are two million home owners in Tier 3 or Tier 2 wildfire areas. There is zero probability that we are going to tell those people, "Oh, time to leave. Moral hazard here. We shouldn't have put you here in the first place; you have to go somewhere else." That would be, frankly, an economic catastrophe for the state. The value destruction in abandoning those homes and communities is a nonstarter, politically. Come on. So how do we deal with that? How do we deal with the people that are already in place, as distinct from the people we would hope do not choose to move there, because there's new construction?

Another issue is that there are multiple kinds of rates or charges involved here. An important question is, how much space is available in electricity rates, as opposed to other socialization channels? So, insurance in California, as was mentioned, is heavily regulated. It's also far below the national average. Electricity rates are among the highest. Of course, as rates get even higher, as they are likely to do, the value of substituting some or all of your load to solar or some sort of distributed energy that's a net-metered product grows, the attractiveness of that grows, and there are issues with kind of cream skimming and financing the utility system that become more challenging as the rates go higher.

This may sound like, "Oh, we should think about putting, the cost in home insurance rates." A reason to think twice about that is that socialization of costs in a new way is essentially shifting risk, current liability and/or future risks, from one party to another, and, when you do that, you may break the thing that you're shifting the risk to, even as you fix the thing you're shifting risk away from. So, under an extremely imaginary scenario, if the legislature were to, for example, in California, change this inverse condemnation interpretation by statute (maybe that's possible, maybe it's not), essentially, they would be shifting risk to home owners' insurance policies. The home owners' insurance market in California is also under stress in these areas, and, if you were to do that without thinking about addressing those conditions, you could well just precipitate a crisis somewhere else. And I think this is a really important aspect of dealing with these new emergent catastrophic risks.

This is a picture from 1929 of the town where I live burning down. The fuel loads where I live are three times higher than when this fire occurred. And it's basically the place where the insurance industry believes the utilities will go bankrupt again, or the state might go bankrupt.

One key message that I have is that the scale of liability matters for whether and how it can be socialized, and the first step that utilities need to be taking is accurately assessing risks before they are liabilities and taking much more effective and targeted action to mitigate them.

I think there are a lot of lessons to learn from other companies outside of the utility industry that are exposed to international competition and have really had to focus on quality improvement and productivity improvement in order to remain competitive. To some degree, that kind of experience exists in the INPO environment, in the nuclear environment, and maybe we can adapt that experience to wildfire. I think it's unclear.

Abnormally large liabilities, such as those associated with wildfire in California, exceed, I think, the delegation of authority to PUCs. Whatever the law says, the politics say different, and legislative input is needed. Maintaining trust in that context is absolutely critical to getting a socially optimal outcome.

Socialization of liabilities can be accomplished via multiple paths, and the choice of the path matters. It matters both in terms of getting to an optimal set of incentives for all risk bearers, and it matters in terms of taking account of the situation when the risk becomes crystallized and liabilities become apparent, because we don't start from a clean slate. I wish we could. I wish the last 50 years of development pattern in California had been managed a little bit differently, perhaps, but here we are. Thank you.

Clarifying question 1: There was a lot there. Thank you very much. I just want to make sure I understood what you were saying when you talked about reliability as "unpriced." That really hooked me, because I'm not clear on whether you're saying that you don't have an ability to price that piece into the component when you're assigning the charges, or whether you mean it's a public good, so, you know, that's a service that you have to provide and socialize? I was just really curious about what you meant by reliability being unpriced.

Respondent 1: What I meant was that customers do not ordinarily have a choice of different incremental levels of reliability to purchase, and that we essentially assume that a similar level of reliability will be provided across the utility's distribution system. And that may not be appropriate, because providing it, obviously, is costing widely varying amounts, at least in the context we find ourselves in in California, and I think more broadly in the western United States. And so, we need to more deeply interrogate what it means to provide the same level of reliability to all customers, and whether there are customers in certain situations that should be charged more for that same level of reliability or given the option of purchasing less.

Questioner: So, are you as much talking about the transmission cost as the generation cost, or are you packing that together? Are you talking about the actual voltage and bars and stability kinds of costs, or are you just putting that all together and just saying, "reliability?"

Respondent 1: That's a great question. What I'd say is, I'm thinking about safety types of issues, like frequency of interruption of service, but certainly other types of power quality are things that are important to certain customers, and things that that they might invest in or seek to have those costs socialized. Yeah, that's potentially also true.

General Discussion.

Question 1: I want to just kind of quickly put this in a couple different perspectives. Perspective number one is recent. This is an existential issue for us, because we have contracts with the utilities, and so, when your counterparts are going bankrupt, I'm spending a whole lot of time, for the second time in my life, in the PG&E bankruptcy, and not looking with a great deal of enthusiasm to what may happen to the other utilities. So, this is a big deal, not only for those existing contracts. PG&E has about 42 billion dollars of long-term contract exposure here. So, obviously, we have an immediate interest in that. However, going forward, you've all heard all the wonderful things we want to do in California. That's going to require a lot of capital, and if we're going wildfire season to wildfire season, it's not coming here, so that's obviously a big issue. My family was in Paradise since the 1950s. They pre-deceased the fire, but I'm very familiar with that area. These are people largely on fixed incomes. They're not going to put a Power Wall in their garage. You know, the Kardashians' house burned down, and that was a big deal, in the Thomas fire but, you know, the entire town of Paradise burned down, and it was obviously a big deal.

On the issue with respect to de-energizing lines, what's interesting about that is that you have to have a plan to do that. My brother was a wildland firefighter in east San Diego County when San Diego threatened to do that 15 years ago, and they all went nuts in terms of, how are you going to pump water to put fires out if you don't have energy? So that's pretty obvious.

And just one last footnote, and then I have a question. Speaker 4 indicated that they shut the power off during last October, and to use a very elegant word, that really pissed a lot of people off. There was at least a week of headlines about the insensitivity of PG&E and shutting off all of these rural folks. The first time I ever heard that there were 22 downed lines was 15 minutes ago. I follow this issue, and that de-energizing activity, in fact, probably prevented a large fire. And then the blowback when Paradise burned down was, "Well, why didn't you de-energize those lines?" There's no way to win that.

You know, we're in a, "We've got to fix this" mode, and an adapt mode, in California right now, spending a lot of time in the legislature on these issues. If you had three points that the legislature ought to be looking at in terms of addressing these issues, what would they be? Or even one point? [LAUGHTER]

Respondent 1: I guess I think that there is a question about how we manage the expected liabilities, and I think that's really important. I'm not going to actually comment on that. But what I would say is that there are multiple options. The Governor's team has said that all options are on the table. One is liability reform, one is creating some sort of insurance mechanism for utilities, and there are others. But I would argue that the thing that is really being neglected is getting at the physical risk, and the tool that San Diego has shown to be effective is power shut-offs and, as you said, when PG&E has tried to do that, it has caused widespread customer blowback. And I would love to see more efforts, legislative or otherwise, focused on how to mitigate the customer impacts of power shut-offs. That is something we really need to invest in as a state. It touches on a lot of the issues in my talk, but it's an enabling investment in safety. It's not the direct investment, but it's managing the politics of creating safety.

Respondent 2: One of the is to relook at how we classify customers. Obviously, if you're in a high-risk area, there's certainly a cost-based reason why you'd want to put those customers in a different rate classification than other customers who are not in high-risk areas. Or, to put it in Hoganese, to send the locational signal that you're going to pay the cost of where you choose to be. So, that has two advantages. One is, it follows the principle "cost causer pays," but the second principle is, it basically makes public exactly what those risks are - it becomes much more transparent. Right now, if all home owners are paying the same rate in the same rate classification, you're not sending any kind of signal at all. So, it makes sense to try to do that. So, I think revisiting the rate classifications would make sense.

Respondent 3: If you're thinking about being the legislature right now, as you brought up, the critical path issue in my mind is financial stability of the utilities, so that we can do all these other things. Right? So that we can continue to invest in low carbon and zero carbon generation, and so we can invest in risk mitigation. There are a lot of things that need to be done there, and I think the biggest thing that we need there – so it would be my number one priority – is some sort of clarity about cost recovery. I think there are a lot of people out there at the utilities who would say, "Inverse condemnation is unfair, let's just get rid of it." That's a political nonstarter, but I do think that there are some interesting conversations to be had around a couple of different policy options, the first being, could you create sort of an *a priori* mitigation standard? You know, can you create a wildfire management plan and then have some sort of a legislative intervention that says, "Well, gosh, then what you're going to do is you're going to go to the CPUC and you're going to put up your plan, and you're going to put up what you've done, and, if you've checked all the boxes, or 80% of the boxes, or whatever it might be, those are costs that you can pass through."

I think the other piece around inverse condemnation that is worth some question is, who should be allowed to make those claims? Right? To my mind, a property owner who loses their home and has a coverage gap - that's something we've got to take care of, but I think the role of the insurance industry here is really important, and I do really question why we would continue to make the utility be the reinsurer of last resort. And, relatedly, I think there should be some conversation about the insurance industry in general and what's going on with rates, because that's the other way to send the price signal, and, to me, the thing that's potentially attractive about using insurance rates to do that, is that, while it's not perfect, it might get you closer to sending a locational signal that matters.

Respondent 4: I think there is a real focus on the current crisis, but I'm equally concerned about forward-looking signals. I do think the issue of liability reform could be important in this respect. The strict liability regime, for some of the reasons you've mentioned, it's kind of 20/20 hindsight, and it doesn't really so much focus on forward-looking expectations or standards. A negligence standard might be more forward-looking and, if that were internalized, that might help in averting these kinds of future crises. I do think it would be helpful for the legislature to authorize risk-specific reserve funds, which might allow the accumulation of funds over time to address crises like these in the future, and that could help reduce the costs of capital, associated with cap bonds, and could also, I think, encourage both regulators and utilities to do a better job of forward-looking risk assessment. And I also think the broader issue of insurance regulation is something that might need to be addressed. I'm not an expert on this front, but focusing too much on consumer protection or keeping insurance rates low for retail customers doesn't necessarily lead to the best forward-looking risk assessment.

Respondent 2: My understanding (and maybe I'm wrong) is that if the utility does have strict liability, then I think that does need to be revisited. I mean, one of the speakers was talking about multiple causations for these fires. The utility may or may not have contributed. I have no idea about the facts. But if you assume that they made some contribution, there clearly were other factors that contributed both to the event itself and similarly to the size of the event and the scale of the event. So, strict liability, it seems to me, is inappropriate here, where there are other causal factors.

Questioner: It's just that that's not going anywhere. [LAUGHTER] We tried that last year, and the reality is that that is the status of the law. Now, there may be ways around that. The courts may address that at some point in time, because there are subtleties that you're pointing out, but I do not see the legislature, this session, changing inverse condemnation. It's not even the statute. It is the way the courts have been interpreting the Constitution, for all the reasons that you've already stated.

But I also just want to say (and I'll probably never be invited back to a Harvard event now) that locational pricing is not going to work here. We used to actually charge people an extra $100 or $200 a year for living in these high-fire zones. Politically, that was hugely unpopular, and it went away. I don't want to rain on anybody's parade, but the politics of this are very real. On your way to the airport tomorrow, or today, or whenever, look outside when you're driving through this canyon here. That's what you're facing. I don't know when the last time was they had a fire here, but right now it's nice and green. In September, that's a bomb. Okay? So that's really what we're facing. But thank you. This has been a very good panel. I wish, actually, some of our legislators had been here to hear this, because I think you put a lot of good thought into this. Thank you.

Question 2: I wanted to pick up on some of the comments that people have made about being forward-looking and 20/20 hindsight. The first time I heard about inverse condemnation was over a year ago, before the wildfires, and it was Geisha Williams, the CEO of PG&E, saying that the company, by underwriting the wildfire liability, regardless of whether they were negligent or not, they were being put in an unsustainable position, saying that, if you had a wildfire (and the probability was that there would be wildfires) they would be obligated, then, to issue bonds to pay for the damages and then collect that from customers, and that that was unsustainable, particularly because of things like community choice aggregation, where people were forming groups to get out from under these costs that had been built up.

So, my question is, does the panel think that this PG&E bankruptcy was inevitable, given the probability of wildfires and the existence of inverse condemnation? Is this an example of how it takes a crisis to actually deal with a serious problem? And did the community choice aggregators not have any of this liability, even though they were an alternative for customers?

Respondent 1: I'll just say that I don't think the bankruptcy was inevitable. San Diego is a great example of how it could have been avoided. That would have taken foresight and strategic vision that sadly wasn't achieved, and this really doesn't have to do with Geisha Williams' tenure. The actions would have probably had to have been taken before that.

CCAs pay a wires charge to PG&E to deliver power over PG&E wires to end-use customers. My assumption is that as these wildfire costs are built in to rates, they will emerge as an important component of that wires charge, because they're associated with the wires and the cost of building, operating, and maintaining the wires.

Questioner: Do we know right now whether that's developing or not?

Respondent 1: I'm not expert enough in the proceeding concerning development of the wires charge to answer that question.

Respondent 2: So, just a very narrow legal point on this. Technically, under this inverse condemnation doctrine, there are cases about things like construction workers hitting rocks with backhoes and making sparks that cause fires, and they are also liable in inverse. So, it's not the status as the utility or as the wires company that matters, it's the status as the person who took the action, or failed to act, in a way that caused the fire. So, theoretically, to the extent the CCA owns equipment that could spark and cause a fire, they would have exposure, but, because they're using the IOU's transmission structure, and they're paying wires charges, they are less exposed to direct liability.

Respondent 3: As to whether it was inevitable, if we think back to the last PG&E bankruptcy, we deregulated the markets and didn't allow PG&E to pass their costs on, and here, of course, we have another significant cost that PG&E is not allowed any mechanism…It might come back to cost recovery and some of the points you were making about cost recovery and the need to seriously address that to avoid these kinds of inevitable rock and hard place problems for utilities like PG&E in the future.

Question 3: Thank you. This is a challenging problem. I don't know anything about insurance regulation, and I don't believe anything that the previous questioner says about what's politically possible in California. [LAUGHTER] And so I'm going to take advantage of those two ignorances and ask a dumb question here. In the discussion, the one thing that didn't come up, and it seemed important to me, is the fact (I assume) that the insurance industry, unlike the utility industry, is highly competitive. There were allusions to it, people referring to how they have a lot of expertise, they know a lot of things, and so forth, but…

Respondent 1: You need to read the McCarran-Ferguson Act. It's not exactly a model of competition.

Questioner: I'm assuming it is, for the purposes of this question. [LAUGHTER] I could be wrong about that, for sure, because, as I said in my premise, I don't know anything about it. But assuming that, just for the purpose of this question, having a very high deductible is a liability that the utility has to cover, and they can cover it through insurance. So, they could insure. You'd still have the regulatory problem of how much they could pay for insurance, but then you could get the insurance company to come back and say, "Well, you know, I could give you a whole bunch of different packages for insurance, and if you want to cover this region where these people are building homes in a wildfire region, it's going to cost you a lot more, and if you want to insure people in places where there's no danger, it's going to cost you a whole lot less." And in a normal market, then, we would say, "Okay, you pay more in the places where it's expensive, and you pay less in the places where it's cheap, and the usual argument (other than the political one about, "I'm just stealing the money from one group to give it to another") would be, "We don't have a problem here where we're facing a monopoly exploiting this problem. This is just the insurance companies coming in and competing with each other and providing different packages." You could end up with an argument for having that whole process produce differential rates for different locations to deal with the risks that we're talking about here, and now the insurance companies will also have incentives to work with the utility to create something like INPO (the Institute of Nuclear Power Operations) and to do all other kinds of things, because they want to get those costs down, because they're going to be exposed to them, and so on. So the potential, if we can get a competitive insurance market going, is to actually solve some of the really hard problems that come up in normal rate regulation when you're dealing with a monopoly, because you're not asking the monopoly to make the decision about the right places to charge different rates; this is happening because of a market phenomenon. So, what's wrong with that?

Respondent 1: Nothing is wrong with that. My problem, like you said, is that the insurance industry is actually exempt from the antitrust laws, to the extent that applies to the business of insurance, so they can engage in all kinds of anticompetitive activity without any real liability. On the other hand, they are regulated, so if the state of California wanted to deal with that, that makes a lot of sense. In fact, if you do the insurance the way you're talking about, you're right, that should be then reflected in the utilities' rates. The question is whether the utility passes this on to the customers who actually contributed to the utility having to incur some of those costs, following the "cost causer principle." The previous speaker says that that's politically impossible, but it's interesting, because the argument about why it's impossible, that people are going to pay more…you know, it's the usual thing. In California, the word "whine" is a verb; it's not a noun. And so, what you really want to do is get the folks that are paying more now than they have to to whine about, why are they subsidizing the guy who has been in the fire? I mean, it's a two-way street as to how you actually phrase that, but, in theory, I think you're right. That would cause those costs to be identified. It would make them transparent, and then you could transfer those to how you bill the customers.

Comment: My observation, by the way, was just focused on electric rates, not insurance. Insurance is obviously going up in those wildfire areas. I have a colleague, and her insurance went up by four times. It's at a point where a lot of insurance companies aren't providing coverage in certain areas, which then leads to another problem because there are a lot of people that are victims of the wildfire that are underinsured, and that's a huge piece of this. So, you're right on the locational stuff, at least as far as insurance goes. I just don't see it happening with respect to electricity rates.

Respondent 2: I think there are two different insurance issues here that potentially can get conflated, and so I want to tease them out a little bit. The first is this question of real property and casualty insurance provided to home owners. And I think you're absolutely right that that creates a possibility for the insurer to act as a price discriminator and send some signals to people about the areas where they're living. There are really two fundamental problems with that. The first is the P&C (property and casualty insurance) market does tend to be pretty regulated, and there are limits on the rates they can charge, and so it's often really hard to charge a rate that is reflective of risk in that market. The other is, in general (and I think this is changing, with big incidents like wildfires that are happening with pretty regular recurrence) what the literature tells us is that demand for insurance is really highly elastic and is sensitive to pricing, and so if you give people the choice about whether to buy insurance or not, and you price it correctly, most home owners will systematically underinsure themselves. And so, I think the ability of that market to do a lot is limited, and I think this point is also well taken that there are certain areas where the insurance companies will just decline to write. In fact, here in California – I'm going to forget the name of it right now – but there is a P&C pool of last resort. So, if you can't buy from any of the commercial companies, there is a pool of last resort that the insurers have to collectively fund. And so, we have accepted, unlike the universal service with utilities, that insurers get to discriminate and pick and choose their customers, so they can create a basket of customers that looks attractive to them.

I think the other point that's important is what kind of insurance is available to the utilities. Rates online for insurance to utilities that cover wildfire liability have skyrocketed. It's gone from about 6-7% to 25%. I think PG&E placed about two billion this year and SDE placed somewhere in the range of one to two billion, but that's for liabilities that they're projecting in the 8-10 billion or more range. And so, you have some issues there with, where are they going to get the rest of their coverage from, and could you price it into rates? If this is something you're interested in, there's a really interesting paper that came out of Wharton earlier this year, where they started to look at some of the potential funding mechanisms, things like captives, mutuals, or whether you would want to have a higher layer of retained risk and self-insure. And I think those are all really attractive things, and likely you need some layering, but that raises some really interesting questions about, could you put that into your rate case, and what would you need to show to be able to do it?

Respondent 1: I want to build on something Respondent 2 said, because this is actually an area that, when I first got out of law school, I worked a lot on, which is insurance discrimination and insurance red-lining. And what's interesting (and Respondent 2 was alluding to this, and it's true) is that insurance underwriting practices, especially in the mass market, like home owners, are incredibly primitive. What they do is, they will simply make stereotypical judgements, or broad judgements, without really trying to look at what the risks actually are. So, if they see a high fire risk, they're almost as likely to just simply red-line the whole area as they are to actually develop more sophisticated products. So, this requires a kind of insurance regulation that actually precludes that from happening. Unfortunately, I've spent hours in discovery on the topic of selling home owners' insurance in predominantly black urban neighborhoods, and what you find is, the underwriters are just simply going through there and saying, "Oh, I saw a black guy in that neighborhood. This zip code, we don't write in." They don't sit there and make judgements about what kind of insurance is appropriate for an individual; they want to know, you know, what's the demography of his neighborhood that we're going to write a policy in? In this case, we're not talking about demography, but we're talking about other geographic characteristics. So, you need a much more sophisticated kind of insurance regulation than probably any state has. Most state regulation of insurance is incredibly weak, so it becomes very difficult to do that. From an economic theory perspective, the argument is absolutely correct. As a practical matter, in terms of how the industry gets oversight of how they do business, I think it would be very difficult to do.

Question 4: Before I start, I just want to thank the panel. It's really interesting information. So, one of the speakers pointed out the importance of customer reactions to some of these power outages, and how you manage them. It's a complicated landscape, and I was just wondering, do you see any opportunity for the building standards and the Title 24 regs and such to play a role in this? I think that's an easy win that we could do.

Respondent 1: I think there's definitely an opportunity to think across silos in that way, and building codes play an enormously important role in all of this, ranging from how the building envelope is protective or not from a fire perspective to what the options are when the power is off. And, certainly, thinking about building into the code for these high-risk areas the ability in the electrical system to manage the power electronics that are required to do backup power, I think it would be a really valuable first step. But where that backup power is going to come from, I think, is still very much an open question, so I wouldn't want to take that kind of step at this point. There's an interesting example in Jefferson, in California, which is the very conservative northeastern part of California, where one of the municipal utilities has just provided gas generators to all their Tier 3 areas. Tier 3 areas are the highest-risk wildfire areas, from a utility definition perspective. And they just said, "You know, we can't afford this. We can't afford to have this risk, and so we're going to be really aggressive with turning the power off, and we're going to fully mitigate that by providing commercially available gas generation to the customers where we want to turn the power off." And things like that might be worth considering, but obviously they have energy efficiency and resource mix implications.

And of course all of this is happening in a context where, you're exactly right, a very significant number of local jurisdictions in California are getting ready to ban new gas infrastructure in new construction. So, a number of governments are considering banning the plumbing. Right? So, no gas pipes, and that kind of gets around some of the utility regulatory issues around obligation to serve. You can't build a building with gas lines in it, so who cares if it can be served by the gas system? Other areas under consideration involve the air quality impacts from combusting natural gas in area sources like water heaters, and whether there's a mechanism there. But, whatever the mechanism, that's the direction California is heading, and so we really do need to be thinking about these reliability questions in a holistic way.

Question 5: Very interesting panel. I take the point about insurance and saying that may be the more natural way to try to look at this than just running it through the utility, and I take the point about turning off the power lines as being the prophylactic tool that could be, perhaps, most effective. But what I'd like to hear more about is a cost-benefit analysis of actually hardening the distribution lines. I'll give a very modest example from my little town of Chevy Chase, Maryland, where Pepco has just a terrible reputation. Finally, the PUC got a lot tougher on them, but also gave them an incentive to improve the circuits. And we were fortunately one of the three worst out of 66 circuits in the area, and so we actually got improved, and the result is that we haven't had a material power outage for five years, after having several with very modest storms causing them. And so, it makes me wonder, would hardening really help, and what is the cost-benefit of this? Clearly, the insurance markets aren't, themselves, going to be able to cause the utilities to undertake those improvements. That has to be done through a regulated return process. But there has to be the technical review of what, in fact, would be the level of improvement that could make a material difference against certain potential hazards. It seems to me that there's a lot of technical thought and work there that has to be done to come up with an answer, but it's crucial, and can make a huge difference.

At the ISO in New England, for the improvements we've made in our transmission system – $10-12 billion dollars' worth– we know exactly what that's costing – roughly 1.5 cents per kilowatt hour added to the tariff across New England. This isn't complicated math. That would be, to me, a realm of political discussion as well. Should there be that kind of incremental investment? Would it make enough difference? How it gets paid for across the different rate categories is a different matter, but I'd be interested in your thoughts about all that. What can really work here, technically, before, or as an alternative to, knowing when you were going to be smart enough to turn off or de-energize the lines?

Respondent 1: All the IOUs (with the possible exception of San Diego which, in effect, has already made these investments) are proposing significant new investments in hardening and what they term "enhanced vegetation management." The challenge with hardening is that there are only so many qualified electrical workers to do the work, and the scale of the problem is very large. So, in PG&E's case, they have essentially proposed kind of full utilization of their workforce to do a couple of things: hardening poles and insulating lines in the riskiest areas. What I find interesting is the point that you made about asking, what is the cost benefit analysis that's happening here? What is the incremental risk mitigation that might occur from a particular investment? And that is the thing that I, at least, have not seen in the filings made to date. There's a proposal to increase electricity rates by about, I believe, 10%-ish over the next general rate case to do exactly this kind of work. What's not in the rate case, so far as I can tell, or in the wildfire mitigation plan that's been filed, is an explanation of how particular investments incrementally reduce risk. And that's an important gap, in my mind, and filling it would significantly strengthen the case for any mitigation measure. You know? And I think the reality, probably, is that there's a mix of things that PG&E or Edison or SMUD need to do to reduce risk in their systems, some of which are hardening, some of which are vegetation management in some more targeted way…you know, a whole set of things. What's missing so far is that cost-benefit analysis.

Respondent 2: One issue that I'm interested in is how, in assessing benefits, we apply different discount rates to future benefits, and how that can have distributional impacts, as well. So, I don't have answers to those questions, but I'm curious about what California and other PUCs are doing on this one.

Question 6: So, California has, as one of the respondents to the last question mentioned, just started a wildfire mitigation planning process to try and figure out what to do next. But there's also a process in California stemming from a 2013 rule making, and they really got it started in about 2015, what we call the RAMP and S-MAP (Risk Assessment and Management Plan and Safety Model Assessment Proceeding) process, which is basically a way of integrating risk into the general rate case process. Utilities will identify top safety risks, and when proceeding, everybody will look through that modeling process, and then they'll go back and figure out, as part of their rate case, the actual proposal for the projects they're going to use to mitigate the risks, and then you track this money and what has been spent, and then you look and see, if the risks were actually reduced, for the next time around and the next rate case process. And so, you're both tracking risk and you're tracking dollars.

It's not yet clear to me how the wildfire mitigation plans are tracking with what was already asked for as part of the rate case process in this risk mitigation process. I strongly suspect that the dollars are additive, but there's probably going to be some squishiness there that's going to have to get sorted out. But, going to the earlier point about reasonableness review, this is what's setting the standard for reasonableness review, and the question of, did you spend accordingly? So, I think that it's getting there. It's sort of part of the broader theme that I think this panel has explained really well, which is, this stuff is hard, it's going to take some time, and we probably aren't going to be able to respond to it instantaneously from wildfire season to wildfire season.

There was also one other question that was asked about the California wires charge and how the cost of insurance or other measures flows. Everything that I know about California rate making says that that stuff will flow through to the wires charge, no questions asked. I'm not concerned about unbundled utility customers escaping those charges.

Now to my actual question. Something that I've been struggling a lot with is, for California at least, the major fires that we've had, both in southern and northern California, in the last couple of years, have really been started by really high wind events. The utilities have high wind standards, sort of general orders that are out there to say, "Okay, here's your standard, and if the winds exceed that, those are the breaks," and then we have these huge fires that happen. And the hypothetical that I throw out to the panel is, let's say we had the exact same horrific fires caused by utility equipment, the exact same tragic loss of life, property damage, everything, but the inciting incident wasn't a high wind event, but it was a major earthquake. For earthquakes, the same general orders apply, where we say the utility system has to be hardened to a certain level, and anything above that is sort of deemed to be unreasonable. I would posit that, if we had the exact same wildfire in Paradise, but it was because of an earthquake, California would not be in the place that it is right now. We would not have the bankrupt utility, and another one that's really, really nervous about going bankrupt. The federal government would have either stepped in, or there would have been other steps available. And I guess the question is, how do we think about Acts of God differently for insurance and liability purposes, and how do we distinguish that from just tried and true negligence, where insurance really is sort of different?

Respondent 1: All right. I will be brave and go first. [LAUGHTER] I think this is a well-placed question, and I think there are a lot of really interesting things to learn by looking at how we deal with hurricane losses, as opposed to wildfire losses, so I think that's probably your best analog. I think one of the big differentiators there is that there has been a much more robust federal response with what we would call the third-party liability. That's where you get to the big ticket items. The costs of putting your poles back up and rebuilding your generation, while not insignificant, are things that we generally recognize as things you can recover. Right? And, in lots of states with hurricanes, they have mechanisms to prefund that or to very quickly pass it through, so we know how to deal with that part. And I think that where you see the gap is in what's going on with the people who lose their homes. Right? You don't have something like the Natural Flood Insurance Program for wildfires. Right? And so, you have fewer mechanisms that are available to make people whole. And I think there are some really interesting social and behavioral economics questions around that.

When it's a natural disaster, people are willing to accept that it's a thing that sort of exogenously happened to us and we, as the American people, are supposed to pull together and get these communities through it. You know, in Texas, every time there's a big giant hurricane, someone puts out some ridiculous statement that's like, you know, "We will be resilient." It's not really resilience; they kind of say, "We're going to fight on in the face of natural disaster." And, if you do anything in the climate world, it feels very wrong-headed to just be like, "We're just going to go right back where we were," but, culturally, that's where we are as a society.

And one of the things that I've grappled a lot with in looking at the wildfire space is the question of, what is different from a sociological perspective? You have the intervening cause, right, of the line going down, or whatever it might be, that changes a bit how we think about responding to the wildfire. And I think, to the well-placed point earlier about the scale of liability, it's something we've really got to think about, if you are willing to accept – as I think most of us in this room would be – that climate is a significant driver of the size of these liabilities. Right? There are some very interesting legal questions about, are climate driven events really kind of force majeure, Act of God events, or do we know enough about their predictability and their certainty that those are sort of – I hate to say it – ordinary but extreme risks that businesses really ought to be managing to?

Respondent 2: Even with hurricanes, it's interesting. That's why I mentioned the example of Katrina and Entergy. Even in hurricanes (apart from making Puerto Rico different than everybody else) we make exceptions, in terms of what FEMA does. If somebody had a way of mitigating their losses and chose not to do that, in that case we said, "It's your problem." So, sorting out what's sort of a privatized problem and what's really a natural catastrophe becomes rather difficult. I mean, you take something like the Johnstown flood, which was caused by, really, private negligence and a private dam and killed several thousand people – I mean, how do you sort that out? It's a flood, so you could argue that it's a natural disaster, but there clearly was negligence. So, it's hard for me to see how that gets sorted out without either a huge amount of political influence or some kind of judicial intervention to sort out who is responsible for what. But - I mean, I think the previous respondent is right – for certain things, we just generally accept that they're natural disasters, and we'll all pull together and help out, but there are a lot of these borderline cases, and I think wildfires may be one of those borderline cases.

Question 7: Do you think that, since California has the California Earthquake Authority and has sort of this recognition that there's this underlying condition of being massively underinsured for earthquakes, do you think that is sort of a differentiating factor in terms of explaining that we don't have the High Wind Authority? You know, an earthquake is going to knock down a pole and cause a fire just as easily as a high wind event, and maybe this is a false distinction, but I'm willing to bet all the money in my pockets that, if this fire had been caused by earthquakes, we wouldn't be where we are today. And, well, we've insured more for earthquakes, knowing that there are these high consequence, low probability events. We've gotten, now, high wind events that are making the system much harder to insure against, so I'm wondering how we reconcile these things?

Respondent 1: A foreseeable earthquake bankruptcy for PG&E is the gas lines, if, I mean, what happened in 1906 reoccurs in some place. Right? Gas lines rupture, as we recently had happen in San Francisco. It burned down one of my favorite restaurants – Geary Boulevard. If gas lines rupture, fires are out of control, the emergency system is overwhelmed, anyway, and you get a major conflagration…if PG&E failed to maintain its gas lines properly, and that occurred as a result of a failure to maintain and operate, you can bet your bottom dollar they'd go bankrupt after that. I don't think there would be any question. And it wouldn't be covered by the Earthquake Authority, because fire is not a hazard that's covered by the earthquake policies that the Authority writes. That's a standard home owner's policy.

Question 8: Thank you. I have a comment and a question. A comment on locational pricing and the politics of locational pricing. I think that in California, you're going to get reduced liability, through the public safety shut-off, with some amount of mitigation. PG&E's plan has some plans to harden some lines or provide for hospitals and fire houses to have more secure service. And then the increased rate will basically come with offers for improved reliability. Either, you know, to have batteries in your home, or to participate in some kind of neighborhood scheme that would protect you, and so on. And what will be real interesting is how that gets negotiated and made available, in an equitable way, to the people affected.

My question is, the bankruptcy is going to open up structural change. One possible structural change here would be for PG&E to sell off their gas unit. And we also have a policy environment where the state wants to shut down gas in homes. You talked about making some homes that no longer having the plumbing for gas, and so on. So now it looks kind of like a mine with a finite resource, so it will be a company that's going to have to wind down. And one concern that people have is, how do we ensure that they safely operate and maintain the gas system in a wind-down situation? And this is not just about the California-specific case. There's probably something similar elsewhere, with shutting down major power plants, or something like that. I'm curious what the panel's perspective is on managing liability and risk for a company that's going to be going away?

Respondent 1: I'll just say that I think this is an enormously challenging problem. We've made large safety and reliability investments in the gas system over the last decade in response to San Bruno. Those are investments that are, you know, designed to be depreciated over decades, and the announced policy of the state is that they want to do deep decarbonization. Basically, you know, starting right now and for the foreseeable future, seeing emissions fall 4% a year. And so, there's this huge stranded asset risk in the gas system, and then there's the separate question about how you manage the network economics as you lose customers--how you maintain safety, how you maintain reliability. It's kind of the equivalent of, you know, the giant discussion that occurred several years ago around the utility death spiral in the context of net metering. I think that is a conversation still to be had in California. And I think perhaps the discussions on the part of local governments about how to implement these kinds of codes will spur that conversation.

Question 9: I have two or three empirical observations. Speaker 1 is 100% right about at least the property and casualty insurance in the state. The ability to do what the previous questioner is suggesting, in terms of using competitive insurance to address the problem and establish costs, is certainly there, and it's certainly not done. People are withdrawing coverage. Similar to the way risk is measured in the tiers, there's also a prevention rating. There's only one underwriter in the state that I'm aware of that distinguishes customers by things like quality of protection, quality of fire services, whether the community does things to remove undergrowth – only one carrier, and it's the most expensive. [LAUGHTER] All the others ignore that. It's uniform pricing. So, there's a lot of room for improvement on that side, and the uniform response is to socialize it, increase rates, or drop coverage. So that's an empirical observation.

I think the earlier speaker's emphasis on the importance scale is real important, because it inevitably points out that the PUC is not the final place that this should wind up. It needs something bigger. I'm not sure exactly how you do it. This goes to the earlier comments about what's politically doable.

And I have a generator, and it's a great example. In my community, you have to deal with CARB (the California Air Resources Board). Okay? If you're over 50 kW you do, but even under, you have some issues with CARB. I would need a coastal permit. I'm in an unincorporated area, but it acts like an incorporated area, and I would need permits from a local land use authority. I have to ask the county for the generator separately from the building permits; the building permits would be state and county, and then I have issues with proper interconnection with PG&E and permits for all that. So, if you're going to solve the problem, you've got to solve all of those problems to make it work.

The same thing on vegetation. Actually, for Chevy Chase, since 1990, Pepco has had little counters that would count faults and resets, so they knew exactly what was going on. Sometimes they don't work, but, in general, they knew. And if you went through the area, you would see trees where there are literally holes through the trees, and that's Chevy Chase's vegetation overlay over Pepco. In other areas, the trees are trimmed so that they grow forked, so in high wind they split in half and take out lines. Where I live, there are literally dead trees leaning against power lines, touching attachments to the power lines. And I've gone out and talked to PG&E guys and said, "I can't get a permit from the county, or in my case, my local community," and, you know, it took three years for them to trim an area. Now, this is not high voltage; hopefully, the high voltage corridors are easier to maintain, but, at the distribution level, the local communities are huge, huge impediments, and the PUC can't do anything about that - at least as far as I know.

Now, with that said, and when we see something that requires more integration than the PUC can provide, what's the vehicle? Because I can't figure that out. I mean, you're using PG&E as an insurance company in many senses. You know, it's the deep pocket, but where do you get the authority to integrate these kinds of solutions?

Respondent 1: That's part of the reason the legislature is important. And, in companion bills to a lot of the utility-focused legislation that's passed over the last year, and under consideration this session, is a lot on changing land use policy. I mean, where I live, you need to get a permit from the planning commission to cut down a tree, if it's over a certain size. In the town next door, you need to plant two more if you cut…so this is a fundamental problem, and I think it goes to larger issues of local control in zoning and building codes that are very much in play in California with respect to the housing crisis we face here, and the question I see is whether the two things become integrated in some way. And I think it requires looking out of the utility silo to manage certain risks that are, you know, borne by the utility silo right now.

Questioner: Even the legislative initiatives don't seem to be resolving that. You know? I mean, why I'm wondering if anybody has insight? Where does the authority come to resolve the fact that it's five stops, or four or five stops, to do this? Resolving even the inverse condemnation for PG&E would only distribute that risk in a different fashion, and you can't resolve the problem under the combined regulatory authorities that exist now. And the legislation doesn't seem to fix it.

Respondent 1: Well, I think there are two issues. One is the issue that a previous respondent pointed out, I think, more articulately than I'm going to be able to do, but, you know, just the general kind of underestimation of the risk that communities face or perceive. The other is just the raw power of the California Building Industry Association and local governments over making the kinds of changes that would be required. And I'm not saying that it's clear what the changes are but, you know, there's a lot of resistance to doing anything that would remove local control and/or limit building in the Wildland-Urban Interface.

I think the insurance industry is actually a place where this might start to change. There are significant limitations, as has been pointed out, due to a proposition, Prop 103, that are imposed on the insurer's ability to raise rates. They're gradually rising, and the insurers are controlling their exposure via underwriting; that is, they're not writing new policies, and they're nonrenewing other policies, and that's shifting home owners onto the FAIR Plan, which is the insurer of last resort. And the FAIR Plan rates are not subject to Prop 103, and they are set actuarily. So, a regular policy in California can only go up by 7% a year. FAIR Plan rates went up, on average, by something in the mid-30s – 30%, 35%--last year, and the most exposed high-risk areas went up by 70% last year. And as home owners are shifted into the kind of insurance of last resort policy, we're likely to see dramatic shifts in the cost and the exposure to paying for this risk, and that may start to change attitudes. And the FAIR Plan also, historically, has done things like brush discounts, sort of trying to price mitigation measures. They don't do it right now. My suspicion is that, as the FAIR Plan grows, what it does will change, but it will not stay the same as today.

Respondent 2: I just want to tack on to this a little bit to touch on the need for community partnerships. There is a behavioral-economic in addition to a purely economic component of this. Right? The brush mitigation pieces of the FAIR Plan are very important, but when you look at the literature, people don't mitigate. Right? There's a great paper by Howard Kunreuther out of Penn. It's years old now, but he was looking at how people respond to the incentives in the CEA policies. And people will not do really simple things like duct tape their water heater to a supporting structure in their house, which costs you the cost of a roll of duct tape and will reduce your premiums very, very substantially. And so, I think that thinking that we can deal with this through pure market approaches isn't really right. I was – last weekend – at a workshop with a woman who looks at climate adaptation in wildfire and lost her house in Santa Rosa, and she said that one of the things she's been most active in right now is trying to go back into her community and explain to them why they don't want to replant all the trees that were there before. They want to live in these beautiful forested communities, and she's going, "But you're going to set up exactly the same conditions that caused it to be a tinder box before." And so I think that there is a lot that needs to be done, and I would argue that utilities should have a really big leadership role in this, because they bear a lot of the risk, to really start to communicate with people about what are communities going to look like in the long-term, so that they are places we want to live, where we can get reliable service, and we are not exposing people to excess hazard.

Respondent 3: You know, the issue with the FAIR Plan, or the insurer of last resort…I've seen how that's played out in inner cities around the country. The FAIR Plan rates go up. In this case, it's not necessarily the same as it is in the cities, where the lowest-income people get the highest premiums, the demography is a little different, but you still have this notion that you've got cream-skimming in the primary insurance market, and then you've got this residual market where you're driving up the price. That insurance may be priced more accurately, but I think a better way to look at this is to think about reinsurance markets, so you don't end up with a residual insurer, but you end up with effective reinsurance markets, so you can spread the risk much more broadly. So that's an area that's probably worth looking into.

Comment: I have a comment, because we've written some of the wildfire mitigation plans in California, and they do include a risk assessment; what they don't include is cost recovery. That's a separate proceeding. And so all of this is sort of in a priority of, here's how we think we need to move forward, here are the high-risk items, here's what we want to take care of. Some of them are super simple, like asking people to start installing covered wire, to take wires off of the trees, you know, it's really basic, but there's no cost recovery guarantee at this point. That's an open discussion, but it's in the wildfire mitigation plans to have some sort of risk evaluation included.