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Rapporteur's Summary*

Session One.
Watching the Watchers: Challenges for Market Monitors

From the beginning of electricity restructuring and market design, there has been a common acceptance of a vulnerability to market manipulation and the need for market monitors. Classic monopoly restriction of supply to raise prices received most early attention. Transmission congestion, poorly designed ancillary service markets, zonal aggregations, constrained-off abuses, and so on, occupied much of the attention of market monitors. But their role continues to evolve. Market monitors provide advisory services, critiquing many details of the design and operation of the many components of electricity markets. Changing conditions involving derivative markets, monopsony power, environmental mandates, transmission cost allocation, reliability concerns, and resource adequacy have presented a steady stream of new challenges for electricity markets and, in turn, market monitors. How are the challenges of evolving markets affecting the role of market monitors? What do the shifting public policy agendas imply for the ability to keep up? What do market monitors have to say about the adolescence, if not the adulthood, of electricity markets? And who is watching the watchers?

Moderator: We're looking forward to a good session this morning. As you can probably tell, watching the market monitors is something that is not only an interesting concept, but one that's incredibly important as well.

Speaker 1:

Thank you. Good morning. Thanks for the opportunity to be here to talk to you all. We know who's watching the market monitors. It's all of you and all the regulators and all the market participants. So now that we've got that out of the way, do you want to go, Speaker 2? Oh, no?

OK, so the general role of monitors in wholesale power markets is a function of the fact that, first of all, laissez faire is not a workable approach to wholesale power markets. Clearly rules are required. Clearly complex rules are required. We all know that from writing and going through the complex tariffs that govern these markets.

In addition, the markets are frequently not structurally competitive. The Commission relies

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on competition, not as an end, but as a means to an end. That is what the Commission would term "reasonable rates." So the role of the monitor is, simply put, to evaluate rules and propose new rules, to evaluate participant behavior, to evaluate RTO actions, to evaluate market outcomes that result from the interaction of those, and in particular to focus on two things, the competitiveness of markets and the sustainability of markets. And that's what I'll be talking about.

The role of the market monitor evolved along with markets. And I'm going to track PJM, but I think generally the evolution of PJM tracks the expected evolution of other wholesale power markets. PJM started out with really just a simple energy market, with a locational energy market. And from the very beginning of the locational marginal pricing (LMP) market there were concerns with market power. The very first filing that PJM made addressed rules for local market power. The result was offer capping for all units turned on for local constraints--offer capping to short-run marginal costs to get a competitive outcome.

The three pivotal supplier test was introduced later as an evolution—a more targeted approach to locational market power, but still, it was in the framework of LMP markets and energy markets alone. And despite much talk to the contrary, I think it seems clear a little bit now in hindsight, there were really no negative results for markets from that kind of market power mitigation. It did not result in suppression of prices, did not result in masking of scarcity, as load pockets typically had supply greater than demand.

The second component of development markets was ancillary service markets in PJM and other markets, particularly regulation and spin. While issues persist there, there are now reasonably competitive markets and reasonable approaches to market power and mitigation of those markets. Those markets remain a very tiny part of overall revenues.

The third step in the evolution was capacity markets. Interestingly, capacity markets were introduced in PJM to facilitate retail access, given the reliability requirements of PJM and the concentrated ownership of capacity. There were market power issues in those early designs. There were inadequate market power mitigation rules in the early design, which we saw in some detail, and which have been resolved subsequently.

But finally, the concentration became not on the competitiveness of local energy markets, but on the sustainability of the entire affair--the sustainability of markets, the sustainability of the overall design. By that I mean, whether the design can reproduce itself, whether it results in incentives to invest, to retire, to meet load. And simple energy-only markets of the kind PJM had were not sustainable, particularly given the excess supply that is required by exogenous forces such as NERC and society's decision not to allow interruptions more than once every ten years. (So we'll need to talk about this local interruption [at the FERC headquarters]…Actually, interestingly, local interruptions are much more frequent and longer duration than those that result from wholesale power markets.)

So there was assumed political resistance--and again, this is an underlying theme--there was assumed political resistance to high energy prices. In fact, I view that as resistance to market power and to non-legitimate high prices. But nonetheless, there was a perception that energy prices would not be allowed to go high. That was the first, I would say, big political impact in the design of RTO markets. But there was no clear articulation at that point of market power issues versus scarcity, and it was a missed opportunity.

It's interesting that people were resistant to high energy prices, given what happened ultimately with capacity prices and the political response to capacity prices.

So there are three basic paradigms out there at the moment, I think, for sustainable markets. One is an energy-only market, and that's what Texas is attempting, with scarcity pricing.

The second is a full locational model, LMP plus locational capacity markets, and the essential features of that are a must-offer requirement for capacity, a must-buy for load, an administrative demand curve which is a function of the reliability requirements determined administratively by the RTO, a net energy revenue offset to make sure there's synchronization between the energy and capacity markets, and market power mitigation. But the design of the market is intended to be a closed model. That is, the market revenues alone are designed to result in investment as needed and a sustainable design.

The third model is a locational energy market, plus something else--what I would call in general plus rate base rate of return or the equivalent. And the models there at the moment I think are California and MISO on the capacity side. So utility rate-base rate of return is certainly one way to finance capacity requirements. RFP-type contracts are another way to do it. Public power, take or pay contracts are another way to do it. They're all really the same fundamental model that is relying on guarantees of payments by rate payers to fund capacity on a bilateral unit by unit basis. But the result of that is that there's no market pricing for capacity. The result is there are no incentives for competitive entry. And if that persists, then ultimately there may be a "competitive energy market" for purposes of doing dispatch, but there won't be a competitive market in the more aggregate sense.

So my view of the role of the monitor in all this is to support sustainable competitive market design, to clarify the choices being made about market design and the implications of them, and to report the outcomes, because frequently we clearly have access to data that others do not. We have the capability to report those outcomes. We have the capability to make the outcomes of some of those choices clear, and that's a central part of our role.

So a recent example of how those different paradigms clash and the relationship between them and our role is, falls under the heading of what's called MOPR, which is the Minimum Offer Price Rules, an attempt to address monopsony power and capacity markets. The basic thesis of MOPR is that participants are not permitted to use out of market revenues to support a low offer in the capacity market. And as we know, two recent examples of states that were moving in that direction were New Jersey and Maryland.

So our role in all that was to support MOPR rules, that is, to address rules and to propose rules that we thought were consistent with maintaining a sustainable overall market design. And that meant not permitting the introduction, really, of the rate base rate of return model, because the rate base rate of return model, if added to a PJM-type capacity market, will ultimately drive out competition. Because if it's possible to finance capacity additions through guaranteed out-of-market revenues, it becomes more difficult, if not impossible, for independent external entities to invest. And the goal was to avoid that happening.

At the same time, we had to be sensitive to the fact that there are other viable business models. For example, the public power model. And the goal was not to tell people that they had to rely on three years out, one year contracts, because after all, everyone had been saying that you should have long-term contracts. (One of the issues in the PJM market is there really is no one generally on the demand side of that with the incentives to take long-term positions.) So our position then became that it's fine if you want to enter into a long-term contract, but you need to do that in a competitive way. That is, you need to do a competitive acquisition. So it's fine to have a 30 years contract or a 20 years contract. But you need to do it in such a way that it's consistent with a competitive outcome, consistent with the structure and design of the market. And our role in all that was to submit testimony, to provide analysis to the market participants of what the impacts were, and to make filings with various regulatory commissions.

Another example of, again, the clash of paradigms, is demand side in the capacity market, and that's where really all the revenues are in the capacity market. (And by the way, I'm not going to be ticking through my slides. My slide set really is background information.) One of those slides shows you that 95% of all demand side revenues are in the capacity market in PJM. But fundamentally demand side in the capacity markets is the sale of interruptibility. You don't pay for capacity, and you agree not to use it when it's needed by others. But the product in PJM has historically been a very limited product. Ten interruptions for six hours, unless I have it backwards. In any case, it's a limited number of interruptions for a limited duration. But the point about market design was that that's clearly an inferior product. And if you let it displace real capacity, either of the demand-side variety or iron in the ground capacity, then you are having a negative impact on the market. You are suppressing the price. And it's an inappropriate part of the market design. It can't really work with the market design. So our position there was, demand side should be unlimited. It should have the same obligation to interrupt whenever the capacity it's not willing to pay for is needed by other participants.

Again, the point is that in order to have a sustainable design, you have to continue to focus on the requirements for that sustainable design, and anything that would undermine it. MOPR is an example. Demand side product definition is an example. And again, we've demonstrated the impact of some of the poorer aspects of demand side design on the dollars in the capacity markets. It's actually reduced revenues in the capacity market by billions of dollars, as has the 2 ½% reduction in demand, what I would call an arbitrary reduction in demand in order to support shorter term demand side in the capacity market.

The final example is environmental regulations. The recent EPA NOPR provided an exogenous shock to the markets, and in my view, the capacity market was actually very well set up to deal with that. The capacity market is forward looking, locational, and permitted the addition of these costs directly to the offers. Again, our position on that was not to suppress price, but to let prices reflect the environmental requirements, and to the extent that units had to add dollars to their units, in many cases very substantial ones, those should be added to the capacity price, and should affect the price. And they did that, and they certainly had some effect on the price. But the point was, to let the market work, to let the market deal with the shock, to incorporate that shock into the market and not to either pretend it didn't happen or to try to suppress prices in the face of it.

So overall, my view of the appropriate roles for the market monitors are first, to support clear price signals that reflect market conditions, not market power--either seller or buyer market power--but actual fundamental market conditions. And let the participants react. So that's the theme of demand side. Have an annual product and let the participants figure it out. Don't overdesign it. Don't create 20 different products with 20 different clearing prices. Have a product, and let the market participants deal with it. They're very creative, and they clearly can do it. You need clear ex-ante market power mitigation rules across all markets. You need a market design which is both competitive and sustainable. Low markups and adequate net revenues support investment when it's needed. Those are not in contradiction. They're entirely consistent. And that's the goal of a good market design, at least from this market monitor's perspective. Resist pressures to design markets to favor specific participants or technologies. Once you start to stray down that path, there are unforeseen consequences. We're seeing that with demand side. Independence is a key feature of the market monitoring function. I think market monitors are a required institution. They're built into the process. They need to be. They need to be separate from RTOs. Market monitors need the ability to file and take independent positions. As I said at the outset, we know the answer to the question. We know who's watching. You're watching. Everyone in this room is watching. The Commission is watching. The individual state commissions are watching. We're watching one another. Every participant pays great attention to what we're doing. So thank you very much. And I look forward to the comments.

Speaker 2:

Thank you. I'm going to focus on a few aspects of a topic which has to do with the importance of the RTO and the market monitor as the independent force looking over the RTO. The monitor has the ability, unlike market participants, to see what's really going on in the market, to understand if an offer is really operating at market, what's actually happening in market power mitigation, what's actually producing price spikes, what's actually going on. And everybody can express views and have opinions about the functioning of competitive markets, but only the market monitor can dig into these things and make sure that what's happening is what's supposed to be happening at a deep level. And to preface my remarks, I probably ought say that the things I'm going to say are my opinions not the opinions of any of the ISOs I've worked with or of any of my colleagues. They're all my fault.

Now, to go into the first topic, and what Speaker 1 talked about, obviously a critical role of the market monitor is to design and administer the market power mitigation mechanisms. And I think that overall, those mechanisms have become much more sophisticated and unobtrusive and more effective than they were when we first started out in 1997 and 1998. But we really have to understand what's happening at a deep level, to not just assume we've got market power mitigation in place, and that it's doing what we want it to do. Because all of these mechanisms have approximations. They have assumptions. There are things in there such that what happens isn't necessarily what you wanted to happen. The design doesn't just happen. It depends on whether the mechanism implements it.

One of the things that the California ISO has been working through in changes to its local market power mitigation mechanism is that they were looking at the congestion components and shift factors on non-competitive constraints and using them for the analysis. And one implication of that, that people don't sometimes realize, I know a number of areas it's relevant, that of course what all of that is depends totally on the choice of the Reference Bus. And depending on where the Reference Bus is, you can completely fail to mitigate somebody that was exercising a mortal lock on the market because of where they were located relative to the Reference Bus. And they're working through that.

But then there are problems of, OK, when you're trying to look at the effect of rig dispatch and how much counter flow you need, it's not just the dispatch up, it's the dispatch down you need to worry about. And they ran into problems there when you talk about how is this actually going to work? And then when you get into calculating the impact of generation dispatched up, and generation down, and relieving the constraint, you also have to remember that there's a load balance constraint, that you don't just move generation down. You've also got to move it up. And when you go into how the software in the market power mitigation is actually doing all these calculations, you need to make sure that none of those approximations are causing you to do something that's radically different than what FERC approved, and what everybody assumes is happening. The software may be doing what people wrote down, but it may not be producing the outcome that you intended.

Skipping ahead to a related topic along the same lines, what I think is a really important benefit of coordinated markets, as opposed to the utility markets we have elsewhere, is that those high energy prices and low energy prices provide you with important information about what's going on in the market. They don't just come from nowhere. They signal that something is going on that we ought to understand. And it can be the exercise of market power, and we have mechanisms and a lot of reports delve into, are these high prices a result of market power? And we look into that as a cause of high prices. But high prices more generally are a signal of, well, is this stress on the stress? Or is something else going on?

And it's important to do that diagnosis, I think, and I think only the internal market monitor and the RTO have the ability to dig in and understand what is producing the high prices. And not stop with, OK, it wasn't due to bids. It wasn't due the exercise of market power. It's just as much a wealth transfer if it's due to a screwball feature of the software, as if it's the exercise of market power. The efficiency consequences might be somewhat different, but the wealth transfer's no different. And maybe the efficiency consequences are equally bad. So I think it's important for them to understand, and when we were doing the price validation for New York for years at LECG, we didn't just look at was this a high price? Was it produced right? We said, well, why was it high? Was this appropriately high? Did this really result from scarcity conditions? Or is there something screwball going on in the software? And sometimes it was things going screwball in the software.

So high prices are good information for regulators and the market participants to diagnose and modify things in the market that raise the question of are these operating policies good? Should we change them? Does this really reflect the value to society of power in these circumstances? So the diagnosis is good and produces a valuable feedback to society in that respect.

But it also is important to make sure that, if it's not due to market power. Is it due to what we think it's due to? Is it really due to scarcity? Or is it due to, we've got an approximation or some software program, or at some point in the design process, the programmer didn't know what you intended to do, so he did something. And you discover what that something was a few years later. And they always will do something. Whenever it's not completely specified, they will do something. And it isn't necessarily documented what they do. You find that out over time.

So I think it's an important role of the market monitor to look at the high prices, to understand, is it market power? Is it not market power? Is it something in our design or in our philosophy about what's important? Is this tradeoff really valuable? And also to dig down and make sure that the software is doing what you intended, that there aren't some approximations in there that are producing a result that's completely different from what everybody expected to be happening.

And I think that that's fundamentally something that the market monitor and the RTO have to do, because regulators can observe those high prices, and market participants can, but even with the data that's posted, realistically you have no clue, no ability to work back into what's producing those high prices and know what's going on. So that's something that the market monitors have to do, and it's I think an important part of their role.

And the same principle applies to uplift costs as well. Even when you think you know what's producing a high uplift cost, it's important to dig into those, to understand what's actually producing them.

And related to this is a view I have of the reports. In analyzing markets and understanding what's going on and trying to diagnose problems and build good designs, I find it very informative to look at high stress outcomes. I'd love to go back and look at what's happening in New England in the winter reports, and Texas in their 2003 shortages in the winter, and more recently the blackouts in ERCOT, to understand as much as I can about, OK, what happened when the system was under stress? And I think we need to do more of that.

In writing up these reports, too often there's no discussion of what happened during the year in terms of extreme events. There's getting to be more of that. But I think there needs to be a lot more. Back at the beginning of the markets in May 7 and 8 of 2000, we had the extreme prices in New York and PJM and New England, where all of the generators went home on Friday seeing a benign weather forecast and didn't change any of their bids over the weekend. It turned out that the weatherman changed his mind, as they do radically, over those days. We had a blistering hot Monday and Tuesday. We had prices, $3,000 in New York, and we were on the very edge of the system. And if you go back and see, well, what was written up in the reports of the time, there's no discussion, virtually, of what happened during those days. Yet, internally it's a very valuable learning experience to understand what was going on and how that worked out in the markets.

Texas has done a lot of good analysis of that in the reports they've written on their cold weather events, but it still is too limited, I think, to the question of whether market power was exercised, and not looking more into the diagnostics of how well did the market operate in this stressed situation. In what I've read so far of what they've written up, for example, about the blackouts this winter, they talked about the fact that generation tripped. But from a market standpoint and design standpoint, to understand how well the design's working, I'd want to know things like, well, did the generators put virtual demand bids into the market to effectively have extra generation committed, because they knew that there was a risk of tripping offline? Or did it turn out that the generators of these units that did trip, did they get really seriously hosed in the market when they bought back their shorts at real time prices of $3,000, and they sold it for $80 or $100? So that whatever employee that put in those bids won't be around next time, that they paid a multimillion dollar penalty? Or did the market not? Was there something about the way that the market worked that that didn't happen, that they skated free, that even though their units were offline, and we had rolling blackouts, that given the way the market was designed, those people didn't suffer the consequences?

Because one thing I saw in New York after 2000, when there were $3,000 prices for imports that were scheduled out of PJM that didn't flow in real time, those people bought back their shorts at tremendous prices. The behavior of those companies changed radically. You could just see that they learned a lesson, and the new employee didn't do things the same way.

So I think that that kind of diagnostic of when we're on the edge of things is important and something that the market monitor can do, and do better than any of us on the outside, because they can really dig in and understand what's happening. I also think that we have an obligation to tell FERC what's really going on, and market monitoring reports should not sugar coat things, and that as much as we complain about FERC orders that are out of touch with reality, you go back and read some of what we've written, and what's been written in the market reports and other things on how things in the market are working, and knowing what's going on, sometimes I can see the shadow of reality on the wall in those reports. But that's about all. There's far too much unwillingness to really say what's going on, to point out that there are areas of the market that aren't working well, and that we need to fix it eventually. And I believe that where you've got a design flaw, and there's a money machine there, you can't describe what the money machine is until you fix it to prevent market participants from taking advantage of it. But we need more frankness in our reports about what's going well in the markets and what's not working well in the markets, and what we know we need to fix in the long run or do better so that FERC doesn't double up or triple up on the parts of the market that we actually feel need radical surgery. So I'll stop there, and take any questions.

Question: Speaker 2, you mentioned, obviously, that an important role of the market monitor is to be the entity to dig in and understand root causes, to analyze high prices and so forth, but I think you mentioned that they were the only ones that could do that, and that the market participants and regulators actually can't do this function, or can't understand or appropriately identify root causes. Can you clarify that?

Speaker 2: I think that in practice, what's going on in the software is so complicated that it's very, very difficult to reconstruct without knowing exactly what bid goes with what resource at what location and what constraints are binding and what they shadow prices were. And often digging back several layers beyond that into what's going on in the software to understand where those prices came from. And you know, there are some obvious things that you can pick up on, but for other things, it's just [too difficult to understand without access to all the information.]

There was a discussion a decade ago about whether market participants should have all the software, so they can see exactly where the hole is and where the money machine is. And I don't think they should. No software is perfect. There's always going to be some ability to exploit it, and I don't think they should have it. And that's why they don't have it, and that's why the market monitor's role is so important. Market participants need to understand generally what the software is doing, but I don't think they should all have a copy of all of PJM's market power mitigation mechanisms that they can run on the side.

Question: So in a sense, it's a structural issue, based on access to the software and the data to do that analysis.

Speaker 2: Yes, and not the bid data, but the data about what's going on in the system--even for the ISOs to go back and rerun their day ahead market six months after the fact is difficult. To get all the data that went into it, and to rerun the real-time is difficult. So it's not trivial to assemble all the information that's relevant.

Speaker 3:

Speaker 1 talked about this first topic a little bit. I wanted to cover market monitoring structure, sort of our functions, and then get into a couple of the challenges. And as everyone in this room knows, electricity markets are not the same as most other markets yet. And we have a lot of potential for the exercise of market power, and FERC has a mandate to insure just and reasonable rates, rather than just let competition dictate the prices.

So in order to achieve just and reasonable rates, FERC has gone to market-based rates, and the court has approved this. I put in one of the quotes from the DC Circuit saying that competitive markets can be relied upon to produced market-based rates. And there's an interesting question there in terms of how does one define a competitive market in this context and who would define it. I think that's an issue that may start coming up more and more as we move forward. I think one of the issues is the recent demand decision that I'll talk about a little bit later. It says that FERC need not rely on textbook economics in making its decisions. So if that in fact is the case, then how does one define a competitive market? So I think that's an issue that is important.

And then FERC has taken the job of making sure the prices are not too high very seriously. The market rules are very detailed. Price caps are in place in many of the markets. They have congressional authority to review market manipulation, an active division of energy market oversight, and market monitors.

In FERC, the role of market monitors has evolved and become much more formal over time. And FERC now requires market monitors in all of the ISOs and RTOs. And they are independent of ISO management and the market participants. And I deliberately used the ISO management rather than ISO boards, because the market monitors don't exist in a vacuum. We report to the boards, and the boards are ultimately responsible for the market monitors and their conduct generally. So market monitors are responsible to the boards, but they're independent of the management and the market participants. And the functions are listed there.

Monitoring and mitigation are sort of day to day functions that are important, and looking at what's going on with participants and referring participants that act improperly is also important. And then market design and problems in new recommendations to improve market design can come out of the market monitoring group.

And what value do market monitors provide? We have to provide some value, I hope. [LAUGHTER] One of them I think is on the ground review of market participant behavior and market operations. Speaker 2 talked about that in a lot of detail. I think it's something that could be difficult for FERC to do on its own. There's a lot of information and a lot of software, a lot of market participant behavior. So having someone who's looking at things in detail is essential.

The other important area is the assessment of the market design and issues that are independent of ISO management. ISO management gets constrained by the stakeholder process and state regulators, and perceptions of what the FERC wants can weigh heavily on ISO management decisions. Choices about where to put resources and what projects to implement are heavily influenced by those things. And I think the market monitors provide value by providing an alternative perspective on that, and perhaps bringing forward issues that might not otherwise be brought forward.

Who watches us? Speaker 1 pointed out that everyone does. But I think it's important to realize that really we're creatures of the FERC like the ISOs and the RTOs, and ultimately, market monitors really can't take any actions that aren't approved by the participants, and as long as someone's watching us, I'm OK. If no one's watching us, then we're irrelevant. So that wouldn't be good, either.

I think the challenges have shifted facing competitive electricity markets and market monitors. We've had a lot of experience and learned a lot about preventing the exercise of generator market power. There's still behavior that requires mitigation or referral, but it generally doesn't affect the whole market. You'll have someone that can exploit price differences that are the result of software or ISO commitment decisions, loss modeling, something like that, where people can make some money. But it generally isn't a large amount of money, and it's generally not affecting all of the prices. So I think we are shifting to an area where getting prices high enough to sustain markets is more of a risk. And we're having challenges doing that because fundamentally we don't really know how much people are willing to pay for electricity. We assume we know, and we give it to them at some flat rate, but that doesn't really help us understand what people would be willing to pay. So until we actually know how much demand values electricity, it's not clear that we can actually get the prices right.

So properly pricing scarcity in the energy market is the fundamental problem, and because we're not pricing scarcity right in the energy market, we've had to create capacity markets and properly price them, which I think is even harder than properly pricing the energy market. And working in ISO New England, I have seen the regulatory intervention, particularly at the state levels, grow exponentially. When we put the market in place in early '99, 2000, that timeframe, states were not very active. They didn't really understand the 205 process, how to work with the commissions. Now the states, I think, have filings written before we've even thought about what want to file from the ISO side. The states are much more active in the whole process.

I'll talk a little bit about the capacity market and a little bit about Order 745 in terms of describing a couple of specific areas where getting the prices right has been a challenge. In New England's FCM market (forward capacity market), the design objective was to have new capacity set the price when new capacity was needed. A fairly simple concept. People recognized that there may be resources brought in that weren't priced at their cost, so an alternative price rule was put in. That was a weak rule. It's in litigation. One of the weaknesses was that it didn't carry out of market capacity over from year to year, even though the capacity existed for many years. And so we've had about 2,500 megawatts of out of market capacity clearing in the first four auctions. And to put that in perspective, the middle row in that table, NICR, is the net installed capability requirement, or New England's capacity requirement. And you can see that the growth there was, let's see, it went up a couple of hundred megawatts between one and two, dropped a few hundred megawatts between two and three, and went up a couple of hundred megawatts between three and four. So the 2,500 megawatts of out of market capacity is going to have an impact on the market clearing for quite a long time. We do have about 4,000 to 6,000 megawatts of old oil units that run maybe 1% of the time, maybe less. Those units are likely to retire once the floor price—it's currently in the capacity market--goes away.

Right now (I should have mentioned this before) the capacity market has a floor price. It's $2.95. It's going to continue for a couple more auctions, and it's been quite successful, I think, in getting capacity. So from, the engineers are quite happy. We have a lot of capacity, about 5,000 megawatts more than we need, which I think is a testament to the effectiveness of floor prices in keeping capacity around. So how that plays out will be very interesting. Where's the out-of-market capacity coming from? One of the main places that it's coming from is state activity. Connecticut issued RFPs for energy, the clean energy plan, which is a large combined cycle, and a peaking capacity. So they added 1,100 megawatts of out-of-market generation. And to sort of put this in proper perspective, Connecticut was under a lot of pressure from ISO New England to solve a number of reliability problems. So that capacity was as much a response to those requests as it was an attempt to influence a market price. But it still has the same impact of increasing capacity and likely forcing the capacity price to be low.

And also the states have aggressively pursued energy efficiency in New England. We're adding 200 to 250 megawatts a year in energy efficiency resources. Will new capacity actually set the price? I think it's important that there be some prospect that it does, otherwise I don't think we'll see merchant investment at all in New England. And investment will be coming through means where rate payers are essentially on the hook to fund all investment. And structurally, we've got the oil units that I mentioned, that could be leaving fairly soon, and then nuclear units in New England face an uncertain future. I'm sure most folks are aware of the controversy over Vermont Yankee. But all the units in New England are pretty old, except for the Seabrook. The Seabrook plants are the youngest, and they came online in the late '80s. So the other ones are pretty old. So there's a lot of risk there that those are not going to last.

FERC has actually strengthened the price setting rules with the minimum offer price rule. So there is that possibility. However, I think we have to bear in mind that the financial impact of a new unit setting the price would be very significant. And right now the annual capacity built in New England is about $1.1 billion. If the price increased to $12, which is a rough estimate of what the Connecticut RFP resources, which were new peaking units, were paid, it would increase to about $4.5 billion. So that's a $3.4 billion increase on a total bill of about $8.5

billion. That's a 40% increase in one year. I think that that would be a difficult political path, and would be quite controversial in New England. So even if we had the price set, I don't know what would happen. It would be an interesting scenario.

The other area I'll just talk briefly about is Order 745 and demand response payments. FERC has approved paying demand response, and the payments are slightly different from generation. I think the question comes up as to whether or not this mechanism actually results in a competitive market. And there are really two specific concerns that I have there. One is around distributed generation. If distributed generation is allowed to be treated as demand response, it's really being paid differently than generation that's on the other side of the meter. Now, is this correct? And would it provide incentives for generators to be on either side of the meter, or to flip from being a wholesale generator to being behind the meter, so that you could actually get paid for providing someone's load behind the meter as well as earning the LMP from the wholesale market? I think this could be a vicious cycle if it were allowed to persist, and I think existing generators have a legitimate concern that prices that would result from this happening are not the result of a competitive market.

There are barriers to demand response, and paying people that install energy management systems or other load reduction equipment--it may make sense to pay them. However, saying there's a barrier at prices below the retail rate doesn't make sense either, because customers are paying the retail rate now. They don't have to purchase at the retail rate and can take actions.

The disconnect between the retail and the wholesale rate occurs when the wholesale rate is higher. Customers are still buying, even though it's costing more than they're paying for it. That, I think, is a barrier that is worth addressing. So I think this is something that's going to play out for a number of years. And looking ahead, I think markets risk some prices that are too low as well as some that are too high. And I think merchant generation is at risk, at least in New England, because of the political pressure for lower rates and the policy preferences for renewable generation. So we have our work cut out for us to figure out how to appropriately produce competitive prices in this environment. Thank you.

Speaker 4:

Most of my comments are going to focus on observations from the eastern RTOs. We've covered a lot of ground in terms of what the role of the market monitor is. I want to emphasize two things, since I only have 15 minutes.

If you look at this list of the issues that we identify and monitor, the first two are really participant conduct related--market manipulation and market power abuses. If you were to read our Midwest ISO *State of the Market* report for 2010, you'd see that there's one recommendation in the area of market power, one recommendation in the area of market manipulation. Generally we make two to three referrals to FERC enforcement a year on potential manipulation issues. The third issue is market performance. And the fourth is the performance of the independent system operator. We have six recommendations on market performance and six recommendations on operator performance.

I want to focus on what I think people still don't understand, which is that more of our focus is on what the operator is doing than what market participants are doing. When we evaluate high-priced intervals, it's extremely rare that we find that market power was the cause of the high price. We did a study of high prices in the Midwest ISO. That's in the *State of the Market* report as well. And participant conduct is almost non-existent, just in terms of a cause. Operator actions, however, are a significant cause of some of the high prices, and that is the primary reason why independence in market monitoring is so important. I think you can only really be completely objective if you're independent of the entities you monitor, which I think is clear for people to understand when it comes to market participants. I don't think people understood the importance of the market monitor's independence from the RTO initially when they were forming market monitoring units.

One of the primary challenges for me is how to cause your eyes not to glaze over when you look at this list [of roles for the market monitor]. Nobody impacts the market prices and outcomes as much as the operators of the market. And frequently, they haven't read any of Bill Hogan's articles. [LAUGHTER] Or maybe even our reports.

I'll just mention a couple of these areas that we monitor, and then I'm going to show you a graphic example of how operators can impact the market. The first area here that we monitor is how the ISOs commit in real time for reliability and take other reliability actions. So RTOs have various types of head room targets--these are triggers that will cause them to start committing units. If they're conservative, you've going to see a lot of uplift and virtually no scarcity. RTOs operate very differently in this regard. New York, I think, is the most advanced in a lot of these areas. They have a model that runs every 15 minutes that economically commits peaking resources and decommits peaking resources when there are capacity needs. Midwest ISO, on the other end of the spectrum, it's all done by sort of manual judgment by the operators. There are export curtailments, and there is a laundry list of things that operators do when they think they're going to be short.

So in 2003, we issued a report in New York and showed that basically shortages were not being priced. And the way to price them is to attach a value to operating reserves and say, "OK, if you don't have enough resources to meet your energy and operating reserve requirements, and you're going to sacrifice your reserves to keep the lights on for a period of time, that has a reliability consequence. It has a value, and that should set prices." And so we proceeded to put in place operating reserve demand curves, which met with quite a bit of resistance, but I think now is an accepted, very good way to price scarcity. The problem is that you have operators that are looking at a shortage coming, who will take actions that are far more costly than the class of the reserves they think they're going to be short of, and you never see the shortage. That is a fundamental problem.

There are two principles I want to leave you with. And the first one is actually in this area. One of the things we're constantly doing is trying to bring consistency between the market and the market requirements and the operating requirements and reliability. It sounds easy, right? But it's not easy. Operators take actions that imply a certain value of various things, imply the value of a constraint, imply the value of a class of reserves. And if our markets don't reflect that requirement and have the same implied economic value associated with it, there are two things that will happen. The markets aren't going to meet your reliability requirements, and you're going to perpetually have operators having to take out-of-market actions to satisfy the requirements. And secondly, there's no potential that the market prices can signal the reliability value of the various services and resources that are needed on the system. So that's a fundamental issue.

And once you establish what those values are, the second difficult job is getting the operators to operate consistent with those values. If we all agree that spinning reserves are worth $100 a megawatt hour, I don't want to see an operator basically incur an all-in cost of $200 to start peaking resources to back down resources to provide spinning reserves. Right? That's inconsistent with what we said the value is. And it will distort the market outcomes.

One of the things that I think that is important for FERC to understand is that a lot of the decisions that the operators make have dramatic impacts on prices and really ought to be in the tariff. Every constraint in all these real time markets has something called a marginal value limit. This is an economic cost that the real-time market is then told what the value of maintaining flow below the limit on each constraint is. You have to have this value, because if the real-time market doesn't have the redispatch to get the flow below the limit, the models stop, and will just not solve. So you have to be able to solve. So you have to have some value in there. You don't want to be arbitrarily high.

But these values have a tremendous impact on the market outcomes. We've seen values as low as $500. Now, that sounds high, but for a typical redispatch, that can prevent a unit that is $25 out of market from being redispatched to manage the flow on a constraint. The reason you would see a marginal value limit that low in many cases is that the operators are uncomfortable with seeing congestion values that are higher, because participants complain about price volatility and members can leave RTOs whenever they want to. So there is an embedded incentive to try to keep things as stable as possible. One of my most important jobs is to identify these things and stop them. And it would be helpful if we'd put these things in the tariff. I think the reason they're not in the tariff is because people's eyes glaze over. It sounds like a modeling parameter. That's scary. RTOs think, "We don't want to have to have a proceeding at FERC where we argue about modeling parameters."

Well, let me show you how important this is. This chart deals with a methodology that was developed in PJM and exported to MISO and New England. It's called a constraint relaxation algorithm. Somebody decided at some point when a constraint is violated, and you've told the real-time market that the constraint is worth X, that we don't want nodal prices to reflect the value of X when we violate the constraint, because that would be like the ISO setting the price, and that's a little scary. So let's construct an algorithm that pretends the limit is higher and looks for the last megawatt of redispatch we had and price it based on that, which I think to most economists doesn't make a lot of sense. It particularly doesn't make sense when you look at MISO and see that 27% of the time in 2010, it resulted in a zero shadow cost. So we're violating a constraint. And there's no congestion showing up on the system.

This chart shows you how much congestion was wiped out by this methodology in the first quarter. 20% of our congestion in MISO was eliminated. We put the market in in 2005. Do you want to know the first time I recommended that we turn this thing off? 2005. [LAUGHTER] There's no reason to not turn this off. It artificially eliminated real-time congestion of $300 million in 2010. Think about that. Almost a third of a billion dollars of congestion was wiped out by this--well, I won't use any words to describe what it is. I think you can understand my conclusion on this.

But this is the sort of thing I'm talking about. It's not in the tariff. It has a tremendous impact on prices, and there's no reason not to turn it off, other than concern about price volatility. And it has secondary effects on all sorts of things. If you don't price real-time congestion fully, people are not going to schedule on the day-ahead market anticipating this congestion, so you're not going to commit units that can resolve this congestion in the FTR (financial transmission rights) market. You're not going to sell FTRs that price this congestion. So you're not going to be sending incentives to build transmission to eliminate this congestion.

This is just one example. There are actually a number of examples of these sorts of areas that I think is really one of the key focuses of our market monitoring effort. I think ultimately, in the long run, one useful thing that FERC could do is really ramp up its efforts in holding RTOs' feet to the fire in responding to recommendations, because some of these sorts of recommendations can be dragged on and on and on. That one in particular doesn't even require software changes to fix--I know that will surprise a lot of you.

OK, so let me talk about some of the current challenges for market monitoring very, very quickly. I'm not going to go into detail on any of these. I do want to mention number three. We keep talking about monopsony market power. I don't believe monopsony market power exists. I've said it to the MISO states, so I'll say it to you. We're not mitigating monopsonists with the MOPR and other types of minimal price mitigation. I truly don't believe that private load-serving entities would have the incentive to build uneconomically to reduce prices. I think ultimately they'd drive themselves out of business trying to pay for those costs. What makes this possible is regulatory support for those investments. So I'd say what we're mitigating is state action or state intervention in the wholesale markets, and I think it's important to recognize that, because otherwise you make bad decisions. I commend FERC for recognizing in the recent PJM and New England orders that at some point you have to recognize these wholesale markets are under federal jurisdiction, and operate in multistate areas. And you can't allow one state to take actions that undermine the sustainability of the market.

And the last principal I'll leave you with--I talked about the operating principal of having operations match the reliability needs of the system. That same principle operates in the long term. We deregulated these markets because we imagined that the incentives in the long term that would be sent by the wholesale markets would guide efficient investments over the long term, investments that would be more efficient than the regulated regime. So when we look at any number of things that happen that influence the market in the long term, one of the challenges in MISO is that it's dominated by regulated, integrated utilities who build based on cost of service. So when I look at what they're doing, if what they're doing is inconsistent with the market signals, then we have a problem, and we need to adjust our market requirements so that the market prices are consistent with what they want to do. If they want a 20% planning reserve margin, our requirements need to specify that. And that one's easy to think about.

But let's think about transmission investment. Almost everyone believes transmission investment has to be regulated. And maybe it does. Maybe there are market failures, economies of scale and so forth. But if you allow people to build transmission in ways such that you can't reconcile the cost of the transmission with the value it's providing as indicated by the market signals, you undermine the markets, and these markets can't be sustainable. I can't build a generator in a constrained area if I imagine somebody's going to come in and build transmission that is not disciplined by the market prices. It's too big a risk. So that same principle has to apply in the long term. And so I think I'll close there, and hopefully we can talk about some of these issues.

Question: You mentioned that operators were taking actions during potential shortage situations that were more costly than shortage pricing. Could you just give an example to clarify exactly what kind of actions you were talking about?

Speaker 4: Well, the easiest to think about is committing a peaking resource. Some of the lower classes of reserves have pretty low values. And so it's easy for the commitment of a peaking resource to be more expensive than the class of reserves that you're curtailing. But other actions include export curtailments when the prices in the neighboring market are $100-$150 higher than in your market. Demand response--you know, if MISO calls for load curtailments that have to cost $500-700 to protect their spinning reserves, which have a value of $100, that's a fundamental problem. So I'm not saying they shouldn't take these actions, but the value of our reserves we're protecting need to reflect the cost of the actions we're willing to take. And when we take those actions, and they prevent the shortage, those actions need to set prices. And that is a very difficult thing to accomplish. But the RTOs are working on it.

Question: To further clarify, what you're saying is, they're taking actions before the shortage occurs and not letting the shortage pricing show up?

Speaker 4: Yes, usually it's before the shortage has begun, and the action they take moves you all the way out of the shortage. It's hard to convince an operator they ought to take actions that reduce the shortage but keep them in it so that we can have prices that are efficient. So sometimes the shortage is actually begun. Other times it's, they're taking actions in anticipation of the shortage.

Question: You mentioned a number of the recommendations you've made with regard to operator performance over the years, I guess, at least going back as far as 2005. What would be your estimate of what percentage of those recommendations have gotten acted on?

Speaker 4: I would say that eventually I wear them down. But I would say maybe two thirds. There are things as simple as, what assumption does an operator make about their external interfaces when they decide to commit resources? I tell them, trust the market. The participants in the other area, if they see prices rising in that area, well, schedule power in. They say, "Oh, we can't assume that will happen." So they'll commit resources that are much more expensive than the power in the neighboring area. Some things can't be solved. I would say two thirds is probably a good number.

Question: I agree with you that there are problems with congestion pricing, and I think every ISO has an implicit price at which they will go beyond their steady state operating limit. It's easy to find in the manuals, and your solution was to put it in the tariff. What does that do for us?

Speaker 4: Well, let me say something you probably don't know. We've made referrals to

FERC enforcement on RTOs that change these parameters in ways that we've concluded are only intended to just mute prices. Putting it in the tariff would make it clear that, to the RTOs that they didn't, FERC has not delegated them the authority to set these prices. I can't reconcile it. If I was a FERC commissioner, and I knew RTOs were adjusting things in order to get the prices they wanted, I would say, you know, that seems like something I ought to be overseeing, and if I choose to delegate you that authority, fine. But you know, that discussion has never been had. And RTOs set these things at much different levels. Actually, some of them are in tariffs. I think New York filed theirs.

Question: New York and SPP both have it in their tariff.

Speaker 4: Yes. So New York's is at a level that is--I mentioned we've seen it as low as $500, and New York's is at $4,000, which I think is more reasonable. So there's almost an order of magnitude difference between where they sometimes choose to set them.

Question: You think that's the right number?

Speaker 4: What?

Question: $4,000?

Speaker 4: $4,000? I'm pretty comfortable that the actions I see them take to manage constraints would be covered by $4,000. $4,000's not as high as it sounds, by the way. I mean, the nodal price, you may see it at a location, may be $100, if you have a $4,000 marginal value limit.

Question: At the risk of taking us beyond clarifying, how did you arrive at that $4,000? Is that based on some sort of willingness to pay or value of lost load study? Because the reaction, if you decide that you're going to maintain that constraint, would be then to shed load at least locally at that point to deal with that contingency that you're protecting for.

Speaker 4: To be clear, it wasn't my number. New York proposed it, and FERC approved it, and whether or not it's the right number, I think it's useful to get it out in the open and get some analysis in front of the Commission and have some deliberation of what these numbers ought to be. When I look at these things, I tend to evaluate them based on the implied value of the requirement based on what I see operators willing to do to satisfy the requirements. So you could ultimately go back to some more fundamental analysis of value of lost load. But I tend to just look for the consistency.

General discussion:

Question: I was sitting here listening to Speaker 4's talk about how the operator will do things instinctively for reliability that create these inadvertent costs, rather than letting the market work. And I had this kind of out-of-body experience flashing back on how things were done in the olden days, when the power pool was this insider, all boys club, where there were all kinds of rules, and it was one big dysfunctional family, where there was general agreement when you faced the outside, but everybody was interested in cheating somebody else out of a nickel, with rules that looked a lot to me like high spade and the whole takes half the pot and made no sense whatsoever.

And so I'm wondering, how much of this problem is really cultural? I mean, I know when they formed the market in New York, all those guys who were doing these functions were the same guys who were doing them under the power pool days, and probably a lot of them are still there. So how much of it is tied up in the culture about the way we do things, and how will you go about fixing that? Do we have something like mass training, like diversity training, and people have to show up who've bent these rules three times? "Hello, I'm Joe. I'm a recovering operator cowboy." [LAUGHTER] You know? "It's been six weeks since I broke the rule." [LAUGHTER] (I don't actually know what goes on in those programs. I've seen them on TV, though.) [LAUGHTER] I mean, you can't be everywhere, one on one, talking to that one person. It seems like there needs to be kind of a broader orientation, and God forbid would they consider hiring an economist to be down there running some operations once in a…you're laughing. I guess I'll take that as a no.

Speaker 4: OK, so I would say that there probably is some cultural aspect to it. But we see people doing this that have only been there for a few years that weren't steeped in the pre-market way of doing things. And I think a lot of it is human nature.

There are certain things that RTOs and operators get criticized for. One of them is price volatility. And so they naturally take actions to keep things stable. Fortunately, they get criticized for uplift, too. And a lot of their actions in these areas create uplift. So that's helpful.

But I think in terms of, how do you discipline this? You make it visible. You make recommendations that the whole world can see and have figures and state of the market reports that illustrate what they're doing, and you force them to log things really well. And that's a difficult task--do whatever you think you need to do for reliability, but write down exactly what you're doing and why so that we can screen for those actions, evaluate them and root out bad procedures and inconsistencies. But that naturally takes some amount of time.

Speaker 1: Let me just add to that, because I think it is in part cultural, but it's also a lot harder to do that job than everyone imagines. So people are facing difficult decisions in real time, and their primary job is to maintain reliability. So the challenge is to make sure that those decisions are informed by a clear set of rules about the relationship between reliability and economics. I think it's gotten better. It's clearly far from perfect, but that is an area, that interaction, that intersection between dispatchers' real decisions based on their objective functions and market outcomes, that has to continue to be worked on. It is an issue. It's not perfect. Progress has been made, but it's a lot trickier to do that than it sounds. But I think progress is being made.

Question: This question has to do with the sustainability issue, and can these markets be sustained? And an argument could be made, particularly based on things that were said here, that this approach that we have of having hybrid systems with competitive markets, and these rules and market design, as well-designed as we can do it, is fundamentally too hard. And it just isn't going to last, because it's just too difficult to do.

And I propose two arguments that would support that. One is the fire hose problem. So if you're a new commissioner coming on to FERC, and you haven't been involved in these things, and trying to understand what's going on in all these different markets and tariffs and design, there is the drinking from the fire hose problem--you just get overwhelmed with how much information there is, and how intricate it is, and that you in fact need market monitors to keep tabs of what's going on, because you can't tell in any self-evident way. So that would be one dimension of the problem that you're talking about.

And the other is this state intervention story, where you look at what the state regulators say in some of these cases, or you look at the federal level--some of the rules for transmission expansion, where the formal objective that they have is not to have an efficient market, but rather to get prices down, to suppress volatility, to transfer revenues from one group to another group. I've had state regulators tell me, "What's wrong with that? That's my job." So then you have this warring between regulators who are trying to impose the idea of having efficient markets as opposed to short-run suppressing prices for customers or something. So it's both very difficult, and then there's fundamental disagreement about what we're trying to accomplish. Is this model sustainable?

Speaker 1: Let me start. I agree with you, it's very difficult. I think those are just two of the challenges. I think it is sustainable. I think, the first issue is addressable, which is that there's a tendency to make things more complicated than they need to be. They are complicated in some sense, but if you look at the RPM tariff in PJM, for example, I think it's clearly more complicated and less comprehensible than it needs to be in order to get done what needs to be done. But again, the point I was trying to make earlier is that if there is not a general commitment across regulators as well as market participants to efficient design, then ultimately, it won't be sustained. That is, if the participants don't really want it, and those with control over the rules don't really want it, it will not happen. But if there remains commitment to letting the market work with a minimum of interventions directly in the market, I think it can work. But, as we've all found out, it's certainly not an easy path.

Speaker 3: I don't think being too hard is a risk to sustainability. I think that at FERC there's an institutional knowledge that can sort of sustain and deal with the "too hard" issue. The key issues that are embedded in some of the complex question can be vetted and brought in front of the Commission, and the Commission, I think, can understand the consequences of those. So I'm not sure the "too hard" issue is a concern.

But I think state intervention is a serious concern in terms of markets. If the states want markets to actually pay for the fixed and the variable costs, then they have to let prices go high enough that informed marginal rents can cover the fixed costs, and I don't see that as being all that likely over the long run. All of the states have their fingers in the pie. No one in the US has fully deregulated the retail customers and allowed them to go off on their own. So until customers actually have to take action to get electricity supply, and then people have to talk to customers and make long term contracts, I think this hybrid model can kind of limp along indefinitely. But the decisions and the investments will be heavily influenced by state regulatory policy.

Speaker 4: Yeah, and you end up with a cycle of regulation crowding out private investment. So I think the markets would sustain, but you would lose a big portion of what we all thought we were getting in terms of benefits. You'd get short-term dispatch benefits but you'd lose a lot of the benefits associated with long-term investment. And I think the one thing that is absolutely necessary is that FERC apply a sustained, consistent principle in fending off all of the assaults on these markets, whether it's the states, whether it's people, every--I'm looking at my watch, because it's about time for somebody to say, "Why are we paying a clearing price? Why don't we pay as bid?" [LAUGHTER] Or, "Why do we have virtual trading?"-- I mean, these things come back, and I think FERC's really in a position of applying these sort of consistent principles in all the decisions it makes, so that this can work.

Speaker 2: I think you also have to keep in mind--your question mixes two different concepts that always confused us. One is coordinated markets. And SBP runs coordinated markets, and so does the Midwest, as I said, with vertically integrated utilities, who are making investments, which they recover from their ratepayers (and we have rules to make sure they don't lean on the ratepayers in other states) and reliability. And that process of coordinated markets is more efficient than the old New York Power Pool and PJM, because we have shortage pricing. We have better pricing for people making the dispatch decisions and signals for regulators. And then what you're really talking about, what bothers people in the East, is retail access. And no one has the responsibility to make long-term investment decisions for rate payers, and that's not really the same as coordinated markets at the wholesale level.

You need wholesale markets at the wholesale level in order to support retail access. But a lot of the problems we're talking about are really the retail access problems. That's what drives the political intervention and a lot of the problems you're talking about. You know, what should we be doing in the long run in terms of retail access in these states? And maybe that is an area where we're not doing it right. And we're going to have to do it better in the long run if we're going to stay with that model, as opposed to a model where we have a PJM and a New York ISO, but we have someone else beneath that that's making long term commitments for ratepayers.

And frankly, if Connecticut was entering into long-term contracts to buy capacity eight years out, using an open process that anybody could participate in, that wasn't restricted to new generation, or if New Jersey were doing that, would we be upset? Would anybody care? So I think that maybe we have to do something different in terms of retail access. I don't think that anybody's got a great model for that at this point, and it needs to be refined and maybe changed drastically.

Question: I'll start with Speaker 4, and then I'd like the other three to please comment on it, because you all alluded to it in your presentations. Speaker 4, you emphasized the importance of the market monitor being independent. And my question for you and then the rest, is if you could define "independent market monitoring," or if this is like Justice Stewart said about pornography--you can't define it, but you know it when you see it. What does it look like when we see it in terms of structure and relationship to the market participants and the RTO/ISO?

Speaker 4: Yeah, I think independent market monitoring means that we're performing a function where we can be completely objective without being influenced by our interests-- so that drives the restriction against having any sort of financial arrangements with market participants, or potential repercussions from some of the conclusions that we may draw. So in that regard, having a contractual relationship with the RTO where the RTO can't utilize budget or the contract process to influence us is very important--that was actually something that was pretty heavily discussed and litigated at FERC when we were originally formed. For that reason, that relationship is in the Midwest ISO tariff, and FERC oversees it so that if the RTO were to want to replace us, they would have to get FERC approval and explain why. And so providing those protections, I think, is critical for independence.

Speaker 3: I talked a little bit about this, and the independence comes from being independent from ISO management decisions and also from the market participants. And that gives the market monitor the ability to look at the implications of the management decisions for the market and for the market participants. That's the key piece.

But it's not realistic to think of the market monitors as completely independent of everything. We exist in this regulatory environment. We're really creatures of FERC. So our actions are also influenced by our view of how people will react to what we say, no matter how independent you are. I think anyone is sort of subject to that.

Speaker 2: I won't repeat what they have said, but there are two other aspects, I think, that ought to be mentioned. One is, I think there's an importance of independent access to information, to follow up on what I said earlier--that the independent market monitor ought to be able to independently validate what's going on in the market and what's happening, so that they should have some direct access to market data, more than market participants have. And I think also in the end, in terms of operating decisions, ultimately the market monitor can tell FERC what's going on, but ultimately the CEO of the ISO who has a responsibility for the lights going on has to have ultimately authority over what's happening in the market, so that the market monitor should have complete access to the information, be able to tell FERC independently what's going on, but that there is ultimately a CEO that's responsible for the outcomes, who has to have authority in the end over what happens in market mitigation and other decisions, to make sure we aren't driving a train off a cliff.

Speaker 1: Well, I've been both an internal monitor and an external monitor. And I know what it's like to be thought to be independent but not be independent, and to be closer to independent. So being independent I think is being independent of the participants, of management, and of the board for substantive reasons. It has to include the board. The monitor cannot be subject to override or substantive impact by the board, because these boards are not full time boards. They're part time boards, heavily influenced by management. So for true independence, all those things have to be true.

But ultimately, as has been pointed out, we are responsible to FERC. We have a contract, and that contract is terminable under certain conditions. And ultimately at the end of it, FERC will have a voice in whether it gets renewed or not. In terms of what Speaker 2 just said, the monitors don't have independence to do anything. We don't have the independence to intervene in markets, nor do we want to. That is, it's independence to act within our defined sphere. And that is defining and criticizing rules, and making recommendations, reports and findings, and calling out bad behavior. We certainly don't have the independence, nor should we, to be able to intervene in market decisions.

Question: There are a lot of things I could talk about, but I'm sensitive to the fact that there are FERC commissioners here. So I'm going to ask a hypothetical and very general question, but pose a problem that has troubled me for a couple of years, and just try to get the reactions of the market monitors on this panel to that. There's been a number of pretty high-profile instances where market participants have engaged in activities that can only be described as not really having any true economic benefit, but which, for them, produce a financial benefit. And this has taken place under the RTO tariffs. And somebody eventually figures it out, either a market participant or the market monitor. It works its way up the food chain. Eventually a tariff provision is filed with FERC to kind of close the barn door, so to speak, so that this activity can't take place. But in there meantime, often many months have gone by, and consumers have paid a lot of money as the result of this activity. And the prevailing response appears to be, "Well, you know, it wasn't expressly barred by the tariff, so we really can't do anything to get back the money that consumers spent during that period, or the higher prices they paid as a result of this activity." And it doesn't rise to the level of, "the proof required for market manipulation under the section of the Federal Power Act."

I find this really ironic, because we were hoping that when that section was added to the Act, that it would be an additional tool in the tool box to go after people who might be manipulating markets, but that it wasn't intended to supersede the more general case law under the Federal Power Act and the Natural Gas Act that calls for disgorgement when consumers are harmed. So I guess my question is, can anything be done about that? Or are we just kind of condemned to sit there for months and months until action finally happens, and are consumers going to continue to be harmed this way? Because frankly, that undermines the optics of the market monitor regime, and affects all of your work, all of you market monitors. I don't know how to say this any other way, but it gives the whole system a bad name. And it certainly doesn't discourage actions like that in the future, because the lesson is, until the tariffs change, you can get away with it, and you won't ever have to pay any money. So I just would like to bring that problem to the group's attention, and if you all would like to comment on it, I'd love to hear your response.

Comment: Objection. Leading question. [LAUGHTER]

Speaker 1: The problem you identify is real. We see it all the time. And you've seen, as you say, lots of examples that have become public. If something is not explicitly barred by the tariff, then it's very difficult for us to get somebody to stop doing something. I mean, we will have conversations, and sometimes, depending on the compliance regime at the entity, they will stop, but sometime they won't. We certainly don't have any authority to enforce that. Then the process becomes a process of filing a referral, waiting for action, and so forth.

But it's certainly very difficult to get immediate action when it's clear that something egregious is happening, something that shouldn't happen. So it's something that ultimately will be stopped. So there is that lag. And I think it's a combination of tariff changes, with also FERC thinking about how to modify its behavior rules in order to build in the ability, first of all, as you say, to disgorge. And I think that potentially is in the rules right now, going back to the first time that anyone notices to the Commission the action, but also the capability to respond more quickly may be there, because it certainly is true that there are lags when behavior is taking place that we know is inconsistent with competition, which is ultimately corrected, but there's a significant period of time where money's flowing.

Speaker 3: On a more positive note, I think the stakeholder and the regulatory process have become much more comprehensive and thoughtful, so that as we move forward, I think the rules have become tighter. People have seen a lot of things happen because of holes in prior rules, and keep that in mind as things move forward. So I think the rules are getting tighter, and we should see less of this as we move forward.

Speaker 4: Yeah, and one thing I try to remind people of is, we get efficient outcomes because people have the incentive to engage in things that are in their best interest. So if we create a market rule where what's in their best interest is inefficient, and so they engage in inefficient conduct and make money by doing so, that's not manipulation. That is a flawed market rule that you need to fix as quickly as possible. And they can typically be fixed relatively quickly.

We detected something like this in MISO, and MISO was able to make a filing within five days to fix it, and we were able to take other actions to address it in the intervening timeframe. That's not always the case, but I think market monitors really need to be held accountable to resolve these things quickly, because if it's not manipulation, if there's no deception, if there's no fraud, there's just a bad rule, then you can't rely on FERC enforcement or anybody else to try to address this after the fact, so it's got to be dealt with quickly.

Speaker 2: I agree with Speaker 4. I think the essence is speed--to fix the problem extremely quickly. And you go into a bad path if you say, "Well, people do something that's consistent with the tariff that responds to high prices, and we're going to take it back after the fact." I mean, how do you draw that line? There are situations where we're creating new markets and setting things up, and their success is critically dependent on market participants being greedy and putting in bids to exploit that. And there have been times when we were changing market design where we were actually worried that the people wouldn't react enough, because the market design was only going to work if actually the market participants responded competitively and put in bids to get rich. And so we don't want a syndrome where they're not going to respond. But on the other hand, I agree. It's bad when we have a known money machine that goes on and doesn't get fixed quickly. And there shouldn't be infinite stakeholder process to go through to fix that.

Moderator: I think as part of our efforts to increase the transparency of our enforcement process, we're getting better. And without getting into specific examples, I think we've been more responsive when issues have been brought to our attention. We've got a ways to go. But I think, again, defending the agency, that we've improved our responsiveness. But I'll leave it at that, and obviously, feel free to disagree.

Question: I really wanted to follow up on the idea that this system is so complex that only the market monitor can really monitor it. Why does it have to be so complex? Why does the whole market have to be so complex? And what could be done to really help state commissioners and others to really understand what's going on? Because there's a lot of frustration about that.

Speaker 2: The dispatch is complex as we're trying to grind more waste out of the system, and we're trying to keep the rates low. Part of keeping the rates low means optimizing more and more carefully, doing things better and better than the old vertically-integrated utilities used to do, grinding out every nickel, integrating wind. All of this, it's just not simple. Those objectives are what make it more and more complicated, because the software is doing things that, when you look back at what they were doing in 1972 to save ratepayer money, it's pitiful, compared to what they're doing now.

But every one of those things that you do to grind out the last nickel and quarter makes the optimization more complicated and less transparent to those who aren't looking into what's going on in the software. Now, there is the other path of, somehow making the details of all that software available to everybody, but I think that creates many more opportunities for money machines. So I'm on the philosophical side of--don't post all that, and have market monitors that have the ability to in due dig into it and know what's going on.

Speaker 1: And let me just add that we shouldn't underemphasize the degree of transparency that does exist, despite the fact that there's a lot of complexity. There is a massive amount of data. If you go to PJM's e-data or other web pages, there are massive amounts of data. There's certainly lots of data that state commissions can and do monitor, and see symptoms, because what really matters is not what's going on necessarily to every market participant in the guts of the dispatch, but whether it affects prices, whether operating reserves are high, whether there are actually observable market impacts on your customers. And when you see those, you should ask us.

I mean, we try to make information available to state commissions. We both offer it aggressively and respond to lots of questions from both state and federal regulatory agencies. So it's critical to ask. But there are lots of things to monitor, so say you see an issue that's really affecting your customers. Then that's when we can step in and actually try to understand what the underlying reason is, the kind of reason Speaker 2 was talking about, and explain it, or solve it, if there's an issue.

Question: Those of you who know me know that I'm sort of a one issue guy, so I'm going to talk a little bit about transmission. And Speaker 4, you brought this up, and I thought it was a very good point, about a concern that moving away from price signals when deciding where and when to build transmission has a lot of market implications. And I wondered if the rest of the panel might address that, and how much of a concern that is, because there is a lot of talk today about building transmission for reasons other than just responding to congestion and market prices.

Speaker 2: I'm very much in favor of market-driven transmission investment, and the cost recovery mechanism ideally would always be a contract for building transmission. I think this issue is wrapped up in what I talked about earlier. It's retail access. It isn't the coordinated market design. It's retail access. I mean, if you look at it in New York, LIPA doesn't have any problem getting transmission built. They have an obligation to serve their load long-term, and they write contracts with merchant generators and all sorts of people, and they're building transmission. And it's contractual. But the problem is, if we have retail access, who is representing me in the lost load pocket? Well, somebody's going to be in my house in ten years, but it won't be me. I don't want to sign a ten-year contract. But maybe someone should be signing a ten year contract, because someone's going to be in that house. I don't know. But there is an issue, and in talking with developers in some places the question is, who is standing in for the load-serving entity and signing that contract? And then this gets into the ISO policy--so if you're suppressing prices, maybe someone would build transmission and make that investment based on spot prices, but then it becomes really important that we're not doing things to suppress spot prices when they're high. And it's uncertain how much transmission investment spot price investment is going to be support.

Speaker 3: I think this is one of the tougher problems facing the industry in its current structure. For locational reasons, trading off generation and transmission is difficult. We'll be facing this in New England as the old oil units I mentioned decide to retire. Now, there may be some local reliability problems caused by the retirement of these oil units. What's the cheapest way to maintain system reliability? Is it to build another generating unit? Or is it to build additional transmission? How do we make that choice? Who makes the choice?

The current tariff doesn't explicitly trade those off. If a generator, responding to all the market signals that exist, gets built, great. But if a generator isn't on the horizon, the ISO's tariff says we need to maintain reliability, so we'll build the transmission to assure that the system operates reliably. So you'll see a build-out of the transmission system, so that there's no locational differences in New England, if that could happen based on the current rules. But I mean, at some point, too, there's a limit, because you still have to serve the load. Transmission doesn't serve the load. You still need all the generation. So there is a limit to the ability of transmission to solve problems.

Question: But in theory you don't want to build transmission if the cost of the transmission is greater than the congestion problem it solves.

Speaker 3: Well, and that's the tough choice--how do you trade that off when the transmission is generally being built by monopolies, and the generation is being built by the market participants? Who makes the choice between those two, and how do you do it? We've had a lot of problems with locational capacity markets being precise enough and tight enough to actually reflect those costs in the capacity prices. And that's a difficult thing to do. So that's why I say that it's a tough question.

Speaker 4: Yes, I think where the rubber meets the road, if you're not going to go with just private investment, which I think should not be taken off the table, is around the question of, "what are your planning criteria?" So when you start hearing people talk about planning criteria, like consumer savings, you should grab your wallet and be very scared. It should always be production cost savings. That's the true value of a project. Nothing else--we don't have to sit and debate endlessly about what the criteria should be.

But I think where it gets a little bit tricky--in MISO they were talking about building $15 billion of transmission to deliver renewables from the Dakotas and Minnesota area to the East where a lot of states have renewable portfolio standards. So you need to recognize when you start doing that, that this represents a massive subsidy, and it doesn't look as obvious as a production credit, but how you allocate those costs… (If you have a lot of costs to allocate, it probably means you're over-building.) But how you allocate those costs is extremely important, because you can bleed over into very inefficient investment if it's not allocated to the entities that are causing the transmission.

Speaker 1: Let me just add that clearly you're right that transmission has a huge effect on markets, both energy markets and even more significantly capacity markets. We saw that in the recent Base Residual Auction clearing PJM. But it's ongoing. And there clearly needs to be better coordination between the rules that govern whether transmission gets built. There's also a difference that was mentioned, which is that it's a different time horizon. If PJM sees a reliability issue, they're actually required to recommend a transmission solution rather than a generation solution, and the planning horizon for transmission is much longer than it is for generation. So there are a number of areas of interaction between transmission and generation alternatives that need to be made more effective and result in a more market-driven outcome.

Question: There's a theme that I've noticed in the presentations here, and I'll just kind of summarize as I'm going through this. First, Speaker 1's talking about market design and really ex-ante market power mitigation. And Speaker 2 focusing on "What's in the software? Are we making sure the software's working OK?"--and maybe some ex-post analysis, but not too much focus whether market power is necessarily being exercised. That wasn't the emphasis, really, that I got. Speaker 3 was talking about, "Let's make sure we get the prices right." And then I'm hearing Speaker 4 talk about, "Well, we're really not seeing any generator market power," and Speaker 4 made the statement the he doesn't believe in monopsony power at this point.

So in some sense, when we started these wholesale markets over a decade ago, and as a member of FERC's staff, we were really concerned about generator market power. So couldn't we say, to the previous question about whether the system is sustainable, don't we at least have a success here? We've actually conquered something--generator market power's no longer at issue, and we've actually moved on to some of the nitty gritty details of how these markets work, and what we need to look at and monitor, as opposed to the more mundane market power issues that we were initially concerned with.

So I just kind of want to get some reaction to that. And then to follow up on the question about whether we have a commitment to this design. And I think it's something we probably need to be concerned about, and we see examples of that. But I think the alternative is, when we start throwing a good market design, or when we throw a market design that has promise out the window, all we have to do is look at the England Wales Power Pool. The old pool, while it had lots of flaws and lots of warts, was abandoned a decade ago, and now Ofgem [the energy regulator] has started looking at, "Well, maybe we should go to a pool-wide market," and they're looking at various pool-type markets here in the States--PJM, Midwest ISO, etc., realizing that the bilateral market they set up was far less transparent, and actually far more complex than what they thought they were getting in the past. And so there's a sense in which if there's any thought of abandoning where we're at today, the alternatives so far are worse, and what would be the viable alternative to that?

Speaker 4: I'll respond on the market power point. Yeah, I think you make an extremely good point. The market power mitigation measures have been unbelievably effective. I mean, if you told me that whole premise for these markets is that we're going to replace regulation with competition to assure just and reasonable prices, and then you look at a place like New York City, it would be hard to find a less competitive situation than some of the areas in New York City. And yet the conduct and impact mitigation there--it's not invoked all the time. It's invoked maybe 10-15% of the time, and it would be hard to argue that the results in New York City aren't extremely competitive.

So I think you're right that it has been a significant area of success. I think some of my comments are focused on areas of frustration in terms of, how do we get to the end goal of having truly competitive and efficient markets that guide short term decisions and long term decisions? And so most of those issues are in the RTO operations area.

Speaker 3: I wouldn't be quite so wildly optimistic, but I think it has been a success story.

I mean, I think in PJM, the replacement of offer capping everyone who was offer constrained with the three-pivotal supplier tests has resulted in more targeted mitigation. And certainly local market power for transmission constraints has been pretty adequately addressed, across the energy market, the regulation market and the capacity market in particular. But that doesn't mean that generators aren't thinking. As are other participants following their own incentives to find new and interesting ways to exercise market power. So it's still occurring, but it's not the kind of dramatic and overwhelming issue it was at the beginning. It's not gone, but there are a set of very effective rules in place that deal with it in real time and have been generally very effective.

Question: I wasn't suggesting abandoning market power mitigation with the generator side. I'm just saying –

Speaker 3: I know, I know.

Speaker 2: I guess I'll throw in one thing. I skipped over one slide where I talked about how philosophically, I'm in favor of only mitigating people who actually have market power. There's a distinction there. Do we mitigate everybody all the time, regardless of whether we think they have market power, because we're confident we can help energy prices or mitigation prices reflect costs, or are we more skeptical?

Speaker 4, I know, has expressed his skepticism, noting that we can't always measure the costs accurately, and that it's better to restrict mitigation to those who actually have market power. And I think that's a philosophical issue, which is still up in the air.

I'm in favor of limiting mitigation to those who actually have market power, because it's not so easy, and there are particular areas that are problematic in terms of energy-limited resources--in terms of winter gas prices when they spike, and the lags involved, for example. And there's a potential for getting things wrong. And as we move into market power mitigation for longer-term obligations, and things that are even more tenuous to measure costs for than the spot markets, the potential for getting things seriously wrong when we mitigate people who don't have any market power, monopsony, or monopoly is a bad thing.

And to go back and retread some ground, if you think about the problems we've had, and the difficulties for state regulators--and some of the state regulators I've talked to have admitted that, if we had had to go through the spot market, the gas price volatility and oil price volatility that we did between 2002 and 2009 in the old regulated model, we would have never gotten here. Think about what happened between 1972 and 1986. That's how we got to where we are, because that, we couldn't deal with the gas price volatility which we had in that period, which is nothing compared to what we dealt with very successfully over the past decade.

So that's one of the things that has changed. We're no longer sitting on a coal pile that we know the cost of, and that we burn. And the world is much more complicated. That's why the software is more complicated, and my market power mitigation is more complicated. And it's working pretty well. But we want to restrict it to those people that really have market power, in order to minimize the damage from mistakenly dealing with complexity.

Question: Thank you. I'd like to be a little bit of a naysayer to the earlier questioner's hypothesis about the importance of culture. I'm going to suggest that the operator response has nothing to do with an all-boys network, but with the asymmetric incentives that FERC provides at the current time. You have a choice between saving a few bucks on your dispatch, or, if you have an outage, having your penalty be based on the value of load lost. As a former CEO, I don't want my operator doing anything but being very conservative in that equation. So I think what's happening there is responding to the very asymmetric incentives that FERC has set up. I'd like some comments.

Speaker 4: Yes, that's what I was trying to say by the human nature comment. The consequence of the high volatility is such that operators will tend to be conservative. I think what adds to the problem is the fact that if that volatility makes your members unhappy, FERC makes it pretty easy for them to jump out of the RTO. So the RTO has a pretty strong incentive to do what it can to try to keep everybody happy. So that's the other dimension of the incentive problem, I think.

Speaker 3: But I think your point is correct in the sense that the ISO and RTO incentives are to keep the lights on. And the consequences of the light going out are far greater for the corporation than the prices being wrong. If the lights go out, then the CEO is probably not in a very good spot, and the board of directors is going to be looking across the room at each other wondering what to do. So I think operators naturally are going to be very conservative, and companies are going to try and put limits on that conservatism, but they're not going to go all the way to the other extreme, saying, "Get the prices right at any cost."

Speaker 2: We're being thrown a couple of things. Going back, I was involved in New York when they started up and was doing price validation. So I interacted with the operators. And I think there was a carry-over, and the people, they go home at night, and they read the newspaper about high prices. But I actually think the RTOs did a lot to make the operators understand this is a market. It isn't necessarily the case that you've failed in your job, if the spot prices are high. You're not supposed to be managing prices. And I think there were some feedback loops that dealt with that. There was a change in how the operators viewed this. And the earlier speaker's comment, I think, is important in terms of reliability. Remember you said, "It's not whether you set the shadow price high or low. It's whether you set the shadow price to reflect the decisions you want the operator to take." And then they're consistent with what happens in the market.

So yes, you have a bias towards reliability. So you set very high shadow prices for certain kinds of violations, so that they set a high price when they happen. We just don't want the inconsistency between a low shadow price and high price and high cost actions being taken. So I'm not sure that we necessarily have a systematic bias there. I think they have to work on it and make sure operators understand what their obligations are. The conservatism maybe is when the operator has no clue what he's supposed to do, so he figures he should put on another unit. And I guess going back to when they were running the systems without any security analysis of the dispatch, you had to be very conservative, and you had to run the system much looser. Now that we have better software, we can run it harder.

Question: But regarding FERC's recent action with regard to defining penalties for outages based on the value of lost load, that's brand new. OK? That has been in effect for about a year. Doesn't this make the problem a lot worse?

Speaker 2: I don't see why it makes it worse. We now have a value that should be reflected in our decisions. And it should be reflected in our software.

Speaker 1: Well, it might make it worse, because we don't know what the value of lost load is.

Question: I have a question about this concept of watching the watchers. I don't feel like there's any breakdown in the current process for market monitoring, but I wanted to try to tease out the difference in opinion that I thought I heard. Speaker 2, you said that it would not be a good idea for data and software to be in the hands of just anybody out in the market or in the hands of others to allow them to also get an understanding of what's actually going on. And yet, I think Speaker 1 and Speaker 3, your slides in particular, you mentioned that people watching the monitors is really all of us. So those comments seem to be incongruent. If the data's not available to everyone else, how can they really be watching or having a second opinion on what the market monitors say? So I don't know if you want to address that, but those seem to be conflicting perspectives.

Speaker 1: I actually don't think they are. That is, watching the watchers doesn't mean being the monitor yourself. We could have multiple monitors, but it's not clear that would be efficient. As I said earlier, there's lots of data available to every market participant, and lots of participants have very sophisticated modeling capabilities on their own. And the real question is, if there are anomalies, if you see something in the market prices, which are available every five minutes, if you see anything in the flows, if you see anything in transmission outages or unit outages, any of the massive amount of data that's available, then if you don't understand why it is, then you ask and you make an issue of it and make sure it gets explained. So to me, they're entirely consistent. There's lots of data available to those who are watching the markets as well as the monitors.

Speaker 2: Yes, that's what I had in mind as well. Some of those slides, I said, you can see the high prices. You can see things going on in the prices. What you can't see is exactly why that happened. That's Speaker 1 is the one who has to make that analysis.

Speaker 3: And part of the information is confidential. I mean, seeing all of your competitors' offers would raise concerns for collusion as well. So there are limits to what you can share. And the other thing is that the software vendors would want to be compensated if their software was actually made available to everyone. And it's not cheap stuff. So I think it's more of a practical thing.

Question: I want to go back to something Speaker 4 and Speaker 1 hit upon, and sort of set it up this way and ask each of the monitors if they would support a proposal. You heard this morning a little bit about how the Commission has come a long way in properly determining and defining when the lack of a tariff violation is not market manipulation. And the reason the Commission has done that, and especially in the context of flawed market rules, is the Commission struggles with how to define "requisite intent" for manipulation when there's not tariff violation. At the same time, you hear legitimate frustration, I think quite proper, inherent in the earlier question, which is with the idea that the Commission has often said there can be manipulation absent a tariff violation.

It's not clear to me how that exactly could occur, but I think one thing that would actually help a lot, and it goes back to a thing that all of you have said to some degree, is transparency. So one of the things that I think would help the entire process is if we had more concrete and transparent and visible circumstances in which somebody claims there's a potential manipulation of a market without linking it specifically to a tariff violation. So my proposal is kind of simple, and I'd interested to hear all of your reactions to it.

I'd like to see all recommendations and referrals by a market monitor to the FERC be made public. I'd like there to be a new docket at the FERC such that every referral, whether it be enforcement, advisory staff, whatever it is, would be made public, so that we could develop a body of work so that all market participants, you guys, anybody would understand how this process is going to evolve. Because what's really hurting this process is the dearth of guidance as to when something crosses the line. Because sometimes, as you guys know, you make referrals to the FERC enforcement staff. Sometimes they make it up to the 11th floor, and sometimes they don't. Sometimes they get dismissed out of hand, sometimes properly, sometimes they don't. So I'd be interested to know for each of you, whether you would support a proposal that all your recommendations and referrals, no matter where, would go in a public docket at the FERC.

Speaker 1: Well, first of all, I'd say that all of our recommendations are public.

Question: Not your referrals.

Speaker 1: Well, let me answer it one at a time, counselor. [LAUGHTER] It was a multipart question. So our recommendations are all public. And whenever we see something which involves market participants doing what we regard as manipulating the market, exercising market power within the rules, first of all, we contact them. Specifically, we contact the Commission. But we are not silent about it. We then immediately propose rule changes. That process is very public. Marginal loss surplus allocation and loop flow, just to mention two recent ones. All that's very much out in public.

I mean, there's a long list of things we've raised as issues, and you can be sure that none of the issues we see, speaking for us, none of the issue we see of that kind are confidential as to the substance of the issues. We don't name the participant. Presumably you don't want that. But the substance of the issue is absolutely out there.

Speaker 3: I would actually support doing that sort of information release subject to some practical limits such as not exposing the game so that other people could exploit it. So you'd have to have those sorts of limits on it. One other issue I'm sure the Commission would wrestle with is how much do you want to make public, if it would make putting together a case against the offender more difficult? Does that put the Commission at risk and make it more difficult for them to prosecute? That's something that I'm not really qualified to speak on, but I'm sure it's something that would have to be thought about carefully.

I think there is a value in actually naming the participants. We've had many instances in New England that are fairly small, and I think just mentioning the incident in public would be sufficient without a fine. So there is the sort of the old New England stockade value to mentioning someone. So I think subject to some practical limits, making the referrals public may be helpful.

Speaker 4: Certainly more transparency would be beneficial. I get frustrated as a market monitor that I can't figure out what the appropriate standards are. I can think of two or three cases where I have had arguments with FERC where they've told me to refer something, and I said, "I'm not going to refer something that doesn't meet any of the definitions of market violation. I'll notify you that it's going on. You can open an investigation if you want to." I think we're in a stage where there's a lot of confusion about what is enforceable, when enforceable conduct has occurred, and what a market violation is. And I personally think it's damaging for FERC to pursue enforcement actions against conduct where there's no fraud, no manipulation, no violation of the rules, where there's just an unseemly behavior that can be traced back to the incentive that our market provides.

So this goes back to the market flaw discussion that we had. So I would like more transparency, but I think you run the risk that entities that are engaged in legitimate business in these markets and that we need to pursue their own interests suddenly would be facing a much higher risk of… I talk to compliance departments all the time who say, "Well, we're going to tell our traders not to do this and this and this." They don't even want to engage in virtual trading anymore, because FERC is concerned about virtual trading. And if people don't engage in virtual trading, our markets are going to be substantially less efficient, and consumers are going to pay more. So you have to balance those two--the transparency against the risk that you're going to inadvertently motivate people to not engage in efficient market conduct.

Question: But that is exactly the point. And I think your risk is a short-term one that, if not addressed, will become a long-term reality. And that is, because so many market participants don't know where that line is drawn, they're going to err on the side of just exiting those markets. And unless somebody takes leadership and starts dealing with some of these complex line-drawing issues, what's going to happen is, over time people are going to exit these markets, because they don't want the compliance risk. And so what end up happening? That hurts liquidity. That hurts market prices. It hurts our clients in the long run. And it doesn't serve anybody. So at some point, somebody's got to sort of say, "OK, we need to actually draw these lines as best we can." It's difficult. It's complex. But I would submit, if you guys aren't on the front lines of helping FERC do that, who is?

Speaker 4: I totally agree with that. I just don't know whether making all investigations and referrals public is the best means to achieve that. But I agree with your objective.

Speaker 1: Yes, and let me just add on. I agree that the lines have to be as clear as possible, and something Speaker 4 said a few minutes ago is probably the best way to go, which is the moment we see something, to file an emergency rule change with the Commission and try to get it in front of them quickly, so it can be addressed quickly to minimize the issue of this long-term dragging on of an issue. Nonetheless, you're right. It's essential to market participants that the rules be clear as possible. I certainly don't see the situation, at least in PJM markets, where people are considering or in fact exiting the market because of uncertainty about the rules.

Question: I'd like to go back to this recurring question about whether the whole model is sustainable. And I'm starting to get really concerned, because Bill Hogan keeps scheduling panels on this topic. [LAUGHTER] It says to me he is really worried about this. And I want to probe why, and what's really at stake here. And Speaker 2, I want to put the question to you because you said twice, as people were grilling you on this, that the question is not whether our wholesale markets or spot markets are working well for efficient dispatch and short term efficiency. The question is retail access. That's the problem.

And I want to ask you comment a little bit more on what you mean by that. Do you mean that if we gave all retail customers choice by a matter of national policy, and got rid of price caps in the spot markets, would that somehow make the system more robust in and of itself? And I want to also respond to your question about whether anybody would be upset if New Jersey issued its long-term eight year contracts for supply, whether anybody would care. Well, yes, I would. If I lived in New Jersey, I'd be real worried about where the hell that was going, what it was going to cost, and so forth, because I spent most of my career in that old model. And you really see what states are doing as being related to who's going to serve the retail customer--or is it related to, "we want to do something about climate change and environmental issues," which is a related but different problem?

Speaker 2: There are four questions intertwined there. You know, Maryland and several states run procurement processes that buy energy three years forward. So if they also bought capacity three years forward, in an open process, would that be radically different than buying energy three years forward?

Question: No, but they also have a choice in those states, correct? They're buying just for the default supply?

Speaker 2: Well, they're buying it for the default customers, but I think the political issue is that we're going into a contract prior to price volatility. And the question is, should somebody be contracting forward for retail customers to hedge them against gas price volatility and oil price volatility or not? And it's not an easy decision. Because as you go back, how did we get here? NIMO [Niagara Mohawk] was almost bankrupted by those great six cent contracts that seemed such a good idea when oil prices were high. They were so good a few years later. So it's not a trivial question, whether you should contract forward. And is it good for rate payers in the end to ride the spot market, which means high prices sometimes? When gas prices go up, and it's 2007 or '08, it looks terrible. And of course, then when they go back down in 2009 and 2010, we say, "Thank God we didn't sign the long-term contract."

And that's not a simple issue. But that's what underlies some of these decisions. Do you want to contract forward for customers to protect them against 2007 and 2008, or not? And it's not easy. But the consequence of that ripples through to all of these decisions, because if individual customers are riding the spot market, well, they're not signing forward contracts for capacity or energy. And installed capacity markets are not great for retail access markets.

Now, you mentioned renewables, and the fundamental problem is that the federal government isn't doing anything. If we were going to do something about CO2 emissions, it ought to be done at the federal level with a tax, and then we would have some objective standard for what's a good wind investment, what's a good transmission investment to bring in wind? And we're all in a 27th best outcome because we don't have a federal policy. And I think the state regulators are trying to do an appropriate thing, given the lack of an appropriate federal policy. So yes, it's not perfect, but I can understand them wanting to do something. But we don't want to spend an infinite amount of money. So it's tough when you don't have a federal law. I'll let somebody react for a while. [LAUGHTER]

Speaker 1: So with respect to the question of retail access, I agree with Speaker 2 that it's very critical, and in order for the markets ultimately to work properly, you need competition to go all the way down to the meter. And then the end state would be that all customers should be exposed to the nodal price, but then you create the opportunity for intermediaries to come in and hedge that. So it's not a question of whether you make a long-term contract or not. It's giving everybody the opportunity to do it if they want, and not if they don't want, not forcing it on anybody. States are going to serve that intermediary role for a while. If they make dumb decisions, then they'll get some pressure not to do that. But the essential point is to have, as I said, competition go all the way down to the meter and let people have choice about whether or not they're going hedge and how long they want to go out. But certainly having the ability to longer-term contracts makes sense.

The problem right now is, even in New Jersey, where you have a well-developed auction, you're only going out three years. There is no one on the other side, either in New Jersey or generally elsewhere in PJM, no one who has the incentive to be on the other side of a long-term contract, even if it were rational.

Question: I want to tie back two points that were made in the earlier presentations. I loved the line in one of the slides that getting prices right is the greatest risk to competitive market outcomes. And Speaker 1, you then also touched on the fact that policymakers should probably resist trying to incentivize or overly benefit one resource or technology over another, or else we'll run into a situation of unintended consequences.

But given the fact that we are in a situation in which policymakers do make those decisions and those policy choices, how do we structure the markets in such a way in that we get those prices right to ensure a reliable and competitive outcome while integrating some of these out-of-market choices? Or is this a situation in which a revamped and re-energized education and advocacy effort needs to be done to get in with policymakers so that these out of market choices don't distort the competitive market outcomes?

Speaker 3: Until the retail customer is responsible for his own electricity, I don't think you'll see a full market in making investment decisions. The states I think are very reluctant to give up authority over the electricity markets. And they're going to be making decisions on behalf of the customers, which will distort the outcomes. So if states are making investments, they're going to want them to be counted in the market.

I think that's a weakness in the minimum offer price rule. Let's say New Jersey goes ahead and builds those combined cycle plants. Once they're in the ground, I think it would be very hard for FERC to ignore them as capacity, if they're actually built. That would be a very difficult thing to do. My view is, we're going to continue muddling through with this combination of things, and states will make certain investments to maintain reliability where needed. Policy initiatives will go along. Exiting generators will keep going bankrupt until they're sustainable. And we'll sort of muddle along that way for quite a period of time.

The policy initiative that seems to make sense to me is the production tax credit for wind. It's a national thing. It's available to everyone. You can count on it. You can move forward with it. And it's factored into all of the market pricing. So that's the kind of thing where policy can be done in a reasonable way. We have tax policies that affect all of our fuels and investments.

Speaker 1: I would add, just following up on that, it's important to maintain the distinction between modifying the market rules to favor a participant or class of participant, and having exogenous subsidies created by federal policies. It's fine to have subsidies to wind, subsidies to nuclear, subsidies to coal. They all exist, and markets have dealt with them. But it's critical not so skew the market rules themselves so that they favor a particular technology.

Speaker 4: Let me make one quick comment. I think the first best thing you can do is try to educate policymakers to resist using the market to accomplish some very specific agenda. That won't always be successful. But I think the important thing is whether the investment's happening outside the market or within the market. To the extent that you subsidize an investment and that subsidy bears some resemblance to the benefit of that technology that can be demonstrated, then at least the investment that results is potentially efficient versus just forcing things to happen outside the market process, which is far more damaging.

Question: This question is a bit out of left field here, but I'll ask it anyway. And given the activities you all do, which now clearly go beyond looking at generator pricing issues, as you said--kind of operative performance and such, is there a case to be made that in the non-organized market regions, like in the Southeast and Florida, that they should have some version of market monitors looking at the same sort of issues, that have to do with efficiency of the system? They have open access concerns as well, maybe growing more so with demand response and distributed generation or whatever. Obviously it would take on a slightly different character. But there is a kind of nice little constitutional-like structure where you've got the checks and balances in the system. We provide an objective third party view as to market or system efficiency. And that may be relevant.

Speaker 4: Well, it's probably not widely known, but we've done that sort of market monitoring for six different transmission entities, including Duke and Pacific Corps, Mid-American before they joined MISO. In all of those cases, those arose because they wanted to acquire something, engage in a merger, do something where this was sort of an additional protection that mitigated the potential competitive concerns. I think a more general policy would make sense, because in almost all those cases we've found significant issues with how they calculate ATC, how they hold back capability for their own use.

It's pretty clear the reports have a limited audience. Nobody's ever called me to ask questions. But we do things like, we show the actual flows on key interfaces against what the implied flow would be from the AFCs that they're posting or ATCs that they're posting, and what their own reservations are compared to what they're actually using. And to me, it would be extremely valuable to have more transparency into how that process works, because you're relying on a decentralized bilateral contracting business to be going on in those places that is absolutely dependent on how the transmission operator is making transmission available. And so more transparency would be better. And that's one way of getting it.

Speaker 1: The issue isn't whether there's a market monitor. The issue is whether there's a market. There's no market to monitor, clearly, so I mean, the more fundamental question is whether it makes sense or is possible to require all parts of the country to engage in markets or not. The decision's been made not to. Monitoring would only be at best a band aid at that point.

Moderator: We've reached 12:00, but we actually haven't taken advantage of the fact that the two FERC commissioners absented themselves so we wouldn't have ex-parte. So let me, if I could, one final question. To pick up a point that Speaker 3 raised, when you look at the Connecticut situation, and you compare it to the New Jersey situation, one could argue, and I think Speaker 3 was trying to make the argument, that Connecticut had very different motivations, and it was under very different pressures than New Jersey, where the motivation appeared to be to get prices lower. Connecticut had some reliability issues in addition to perhaps that. So it was a market monitor looking at those different motivations, although the consequences are very similar. How do you evaluate that? How do you assess that?

Speaker 3: I don't think it really matters in a sense, for the market. I mean, I don't know if you're going to be referring the State of Connecticut for market manipulation or referring the State of New Jersey for market manipulation. So if you're not going to do that, then getting the prices right is the most important thing. So that goes to the results of the action, not the motivations behind them.

Speaker 1: I agree. I think the rules ought to be the same regardless of the motivation, and we don't always know everyone's true motivation. So if we have the rules set properly, as Speaker 2 mentioned a few moments ago, if there's a competitive non-discriminatory process for requiring the capacity, then that works just fine with the markets.

Speaker 2: Your Connecticut story bothers me a lot, though. Because if there's a reliability need, and you're saying Connecticut's under pressure from ISO New England to buy this, or to build this capacity, and then you tell me it's uneconomic, that tells me that there's something seriously wrong with the market rule, and it isn't Connecticut's fault at all. You know? I mean, maybe I misunderstood what you said, but my reaction there was, well, we've got a big problem in ISO New England's market design.

Speaker 3: Well, the discussions were going on in parallel with the capacity market design. So the capacity market was still being formed. The reliability problems have existed for years. So it was really going on in parallel. And the issue of whether people had faith in the capacity market to solve the problem was a big issue in the minds of Connecticut. The other big issue in Connecticut's mind is that they were unwilling to support a capacity market design that would solve the problem. [LAUGHTER] So it was a mess. But from a state policymaker's perspective, you've got people telling you that you've got reliability problems. And then you're saying, "We'll put this market in so it can raise costs to Connecticut and nowhere else in the region." So how's that going to go over? So it's a pretty messy situation. I'm not –-

Speaker 2: All right, but if they build a bunch of generation in Connecticut, it's borne by Connecticut rate payers. Those costs stay in Connecticut and don't go to the rest of the region either.

Speaker 3: But the total cost of that --

Speaker 2: Anyway, that's another discussion for tonight over drinks. [LAUGHTER]

Speaker 4: Let me say one last comment on this. Reliability can't be the explanation for why the state's taking the action. If there's one thing that these markets are supposed to be pricing and satisfying, it's reliability objectives. If they come and say, "We have some environmental objective, we know that's not priced," then that may be something that needs to be accommodated, but Connecticut--if reliability was the prime motivator, then I don't think that can be considered a valid…

Session Two.

Post Fukushima: If Not Nuclear, What Energy Mix?

Rarely has the future of electric generation seemed so uncertain and fraught with risk. Most energy sources come with baggage sufficient to give investors pause. Amidst regulatory uncertainty, environmental controversy, and the call for a Clean Energy Standard, the future of all energy sources – coal, nuclear, natural gas, and renewables – is unclear. Even before Fukushima, many questioned the viability of nuclear power. No North American investors showed any willingness to put their own capital at risk without substantial government guarantees or other subsidies. It is less probable now that any investors will step forth to take on nuclear risks. Some have raised questions about the ongoing viability of existing nuclear assets. Will oversight of nuclear plants be enhanced, and what effects would that have on the existing fleet? Are we any closer to resolving issues regarding nuclear waste, and if not, where does that leave the industry? Coal, our most abundant domestic resource, is the source of enormous environmental controversy regarding not only emissions of carbon and other pollutants but also its extraction from the ground. The evolution of "clean coal technology" is almost entirely dependent on some form of risk socialization, which remains questionable in an era of fiscal constraint. Natural gas is abundant and available at attractive prices. Yet, growing concern over the methods and substances used to extract shale gas may cast a serious shadow over what had seemed a ready source of energy. Renewables, primarily wind and solar, are certainly the choice du jour, but they remain subsidy dependent, intermittent in nature, and require supplemental supply. Apart from true enthusiasts, few believe that we will be able to meet all of our future energy requirements from renewable sources (even coupled with energy efficiency gains). Given all of this uncertainty, what resource decisions should we be making? Which decisions are we going to be able to make confidently?

Moderator: Over the weekend, I was at the Princeton reunion, and as is the norm, they had the 25th reunion class, which in this case was 1986, unbelievably, marching in and carrying signs of things that happened when they were in school or now. For example, we had 1986, Lady Gaga born. Or another one, in 1986, Oprah's show began. And in 2011, Oprah's show ended. And they had one right next to the Lady Gaga sign. On the front it said, 1986, Chernobyl, and on the back, 2011, Fukushima, which kind of gave me a little bit of a feeling in my stomach, and I think speaks to the challenges of the next panel.

There was a quotation in the trade press last week saying that as a nation, our generation choices have been serially monogamous, that we only seem to like one thing at a time. First we build all the coal. Then we build the nuclear. Then we built all the gas. And now there's an awful lot of money going into wind and demand response. Those aren't self-contained units, of course. But there is some truth to that, I think. And a lot of our generation diversity that we enjoy is really generational diversity, where we're just kind of cruising on the decisions that were made at different times in the past. So now we have a nice diverse pie. But it's just things that came in at different times.

So this panel is here to launch a discussion of what we do about that and how that's going to change in the future. This discussion touches on a lot of the same themes and topics that we talked about this morning--our capacity markets and our regulations; sending the right signal to incent the generation that we need; balancing cost, reliability and the environment; balancing politics and economics; and factoring in decisions at the state and federal level.

Speaker 1:

Thank you very much. I will describe the actions that the Nuclear Regulatory Commission took after Fukushima, and I will finish by telling you where we are today. We activated the incident response center immediately at headquarters in Rockville, where we had people 24 hours a day, seven days a week. About maybe two weeks or so ago, we shifted the responsibility to a group in the office of nuclear reactor regulation, who now follow the event and provide advice as appropriate. We sent a team of experienced NRC staff members to Japan--I think the maximum number at one point was 12 people. And their job was to advise the US ambassador in Tokyo, and they did such a great job that the ambassador is extremely pleased with their presence. But they ended up also advising senior members of the Japanese government. And they also ended up coordinating the US response. The other federal agencies also sent people there. But our guys were coordinating the whole response. And they're still there.

Coming back to headquarters, we issued a so-called "temporary instruction" to the regional inspectors. We have four regional offices around the country, and their charge was to go and inspect the status of the various components and systems that are there to protect the plants from accidents, and especially the ones that are related to the events that happened in Fukushima, which is a total loss of AC power, what we call station blackout.

The results were received after a while, and I call out here two observations. Our inspectors found that there is a potential industry trend of failure to maintain equipment and some strategies are required to mitigate some design and beyond design basis events. However, these findings did not really pose any safety concerns. The words "design basis" and "beyond design basis events" are very critical here. "Design basis events" are a set of events against which the reactors are designed, and they're under very strict control of the NRC, both during the design, but also during operations, where we have regulations regarding periodic inspections, what to inspect, and what to do, and there may even be penalties if we find some violations.

"Beyond design basis events," as the words say, are outside the design basis. And there the regulatory requirements are not as stringent. And one of those beyond design basis events is in fact station blackout. And the Commission issued the rule some time ago on station blackout, asking the utilities and the licensees to submit plans for dealing with an event and what they would do in case they had a station blackout. These plans were reviewed by the agency, and of course, at some point, they were approved.

But the difference between design basis and beyond design basis events is that essentially our involvement after the initial review stops. And this will be, in my view (I'm speaking as an individual, I want to point out, not on behalf of the Commission), but in my view, this will be a serious issue to consider in light of Fukushima.

As a result of the findings from the temporary inspection, we issued a bulletin. A bulletin has a special meaning in the regulatory space. Essentially it directs the licensees to provide some information to the Agency. So by June 10th, they have to respond with information confirming that the mitigative strategy equipment is in place and available, and also to make sure that the strategies that are in the books can be carried out with the staff they have now, in case we have a real accident. And they further, by July 11th, should provide information, about how they maintain essential resources, how strategies are being re-evaluated if the configuration of the plan changes, and so on. So this is information they must submit to the Agency.

We also formed a task force that will report to the Commission in 90 days, (the 90 days end on

July 19th) and there was already a briefing of the Commission on the 12th of May, and there is another coming up on the 16th of this month. And as the name indicates, the near-term review will review what happened in Japan as much as we know, because things are still evolving there. A lot of information is missing. And basically they will recommend to the Commission whether immediate actions are warranted as a result of this experience with the accident.

Their focus is clearly on design basis, because that's where our authority is, but also they will consider beyond design basis--natural phenomena, like earthquakes, tsunamis where appropriate, hurricanes, floods, and so on. And of course, the emphasis should be on mitigating a station blackout event.

Another thing that we don't really consider in these studies in this country is the presence of multiple units on a site. Although we don't have any sites that have more than three units, as you probably know, in Daichii, there were six. They will also look at emergency preparedness and various other programs of the NRC where maybe we need to do something.

At our first briefing in May, the task force reported that it had not identified any issues that undermined our confidence in the continued safety and emergency planning of US plants. The Commission announced after Fukushima, and of course on the advice of the staff, that US plants are safe. They meet all the regulations, and there was no reason to shut them down.

The task force also stated that it's possible that there will be changes in some of our regulations, perhaps, or some of the way we do business, but these will be there to enhance safety. Our primary job is to assure there is adequate protection of public health and safety, and the task force is saying that there is no issue of adequate protection here. You can always enhance safety, but the minimum required for adequate protection is already there.

Following the three month review, there will be a longer-term review, six months after the three months. We hope they will have much more information from Japan by that time, so there will be much more evaluation of what happened. And there will be an evaluation of, or maybe identification of, policy issues that the Commission will have to address, potential interagency issues--in those emergencies, it's not just the NRC. I mean, there are all sorts of agencies, state and federal and local, that get involved. Maybe there are lessons for non-reactor facilities. And we will also receive input from key stakeholders, the industry, and other interested groups, such as public interest groups. And again, we will have a report six months after the beginning of the long-term effort, which is the end of the three-month effort. And our own independent advisory committee on reactor safeguards will review the recommendations, and they provide a letter to the Commission when they do such reviews. So this concludes my presentation. And later on we may discuss parts of it. Thank you.

Speaker 2:

I'm going to start with natural gas and get to its role in electricity towards the end. But let's start with natural gas. I've geared this up to kind of make the case for natural gas, and then I'm going to destroy the case in a sense, just because it's fun, and because this is Harvard, and you've got to do a thought experiment in a Harvard forum, or it just doesn't feel right.

So we're going to start with where our production comes from. The blue circles here on my slide (I think everybody knows this) are our main production areas. The one in the Northeast--the 1.2 TCF is Marcellus as well as the Appalachian Basin. A few years ago that would have been a dot, or a much smaller blue circle than it is today. And that's going to grow as some of the other areas shrink over time, as the shale plays grow up.

In response to these sources of supply, our pipeline infrastructure has grown as well. The INGA folks (Interstate Natural Gas Association of America) have watched these markets and have done a great job of building. This is not the entire Unites States' supply of pipelines. It's what's just been put in place over an eight-year period, roughly when shale was starting to come into play. And you'll see a lot of activity in the Northeast of trying to get the Marcellus shale gas up to the market in the Northeast, a lot in the Southeast, as we're trying to get it to Florida, and growing markets for power and gas-fired power generation.

And you can see the big pipelines across the country, two long ones and a short one that go from roughly Wyoming out east. The point being that we're putting in pipelines that were roughly 2 ½ times what they had historically over this period of time.

And likewise, shale has spawned a boom in the storage fields. So we have…again, these aren't all the storage fields. These are just the ones that were put in place for 2006 to 2010. The blue dots represent the salt dome storage, and the orange dots, conventional storage. And the reason there was a difference is, the salt dome storage can be filled and depleted several times a year. And as a result, they're perfect for power generation. And you can see that they are located where there's a lot of expected power generation. They're not there only for that reason. That's where the geologic plays are. You've got to have salt domes for that to occur. And you won't see them that much more east of that, because that's pretty much where the geologic formation for salt domes ends.

But the point is that the market has responded at triple the rate that it has historically in this four year period to put in storage. So clearly there's something going on. The market is seeing this. This isn't just one set of companies. It's not just one part of the industry. It's all three sectors kind of realizing that something's going on.

Everyone has seen this map [of shale gas plays in the lower 48 states]. I bet no one understands it. This is the shale map and the conventional play map of the United States put out by EIA, the Energy Information Administration. It's a great map. I can't tell you the names of those colors. So I'm going to call one pink and one purple, and I hope you'll be able to figure out which is which. The pink are the shale plays. The purple are the conventional plays. And the main thing that you need to realize about this map is that the purple areas are much larger than the pink areas. The conventional plays are much larger than the shale plays. That's a very, very important point that for some reason no one ever mentions. We'll come back to why that's important in a minute.

So--how shale produces natural gas. I think at this point, especially in this room, everyone knows this by now--but this is a nominal 6,000 foot shale play. You go down a mile or two, and you throw in the water and sand and chemicals to frack it, and the gas is released and flows up the well. If you look at the very, very top of the larger picture, you'll see a very, very thin blue line. That's the aquifer. That's our drinking water. And it's a mile--or at least a mile, sometimes two miles--above where we're fracking. And that's why geologists are pretty confident we're not going to worry about fracking waters coming up from the place we fracked, which are released at the bottom and coming up to the top, because that's a long way to fight gravity.

The inset shows you what we do in the aquifer. You see the thicker casing, basically, around the pipe, around where the aquifer is, and that's where the thickest portion of it is. And the reason for that is, we've got to make sure we protect the groundwater. This is not something unique to fracking. We've been doing this for 60 years this way, with this casing and this technology. This is quite standard. And we don't put anything down in the ground until we hydrostatically test that pressure and make sure that it holds. If it doesn't hold, you start over again. You keep doing that until that pressure test is passed.

So you still might be saying, "Well, why can't the water come back up if you find some way to fight that gravity?" Well, a good reason is that the orange here in this slide shows the impermeable rock. Impermeable rock is exactly what it sounds like. It's rock that you can't get gas or liquids through. It's that solid. It's that tight. And in between you have layers of permeable rock. That's the yellow. And the gas does migrate up from the shale, and you see on the left hand side, you could get natural migration out to the surface that could get in the groundwater and streams and eventually into the atmosphere. It was released. That's going to happen whether or not you're drilling for natural gas. This happens because that's just the way the Earth is.

And if you see off to the right, the migration goes up into an area, and this is much more common, where it hits a little bump in the impermeable rock, and it's trapped. It's marked in this chart as a hydrocarbon trap. You would know it as a gas well. That's where we've been drilling for six years as gas wells. And you can see, to get there, we had to figure out the exact location. You've got to remember this is a two-dimensional drawing of a three-dimensional situation, so in and out of this drawing you've got a third dimension to worry about. If you've got to find that thin layer of gas and find it, very often you hit a dry well, because you just missed.

So what this chart I think conveys is why producers are so excited about shale. For the last 60 years, we've been getting those little traps, which are the dribs and drabs left over from what the shale couldn't hold anymore, because it was so chock a block full of gas. And the shale is the mother lode. And the previous chart I showed you with the map shows that in fact the shale rock, which is much smaller in surface area, is actually feeding this much broader area, because the gas migrates all around.

So that's why the excitement is around shale. We have hit the mother lode, and we can get the gas out much more cheaply than we thought we ever could.

The analogy I like to use is, when we started drilling for shale seriously, and I have to say that was in 2002 to 2005 that we can argue that producers kind of figured out how to do it, and it was expensive. The analogy I use is, and here it is 2011, so a few years later, is I think I'm looking around the room, and I see enough people of my generation to--let me just ask, how many people remember, how many people have ever used a phone that was black, and you picked up the handle, and it was a rotary dial? How many people remember those days? [LAUGHTER] I thought so, yeah. Although this is a very young part of the room over here. [LAUGHTER] After that, if you remember the first innovation, the first innovation was touch tones. And then right away came colors. In my mind, I remember a pink, that princess phone, the pink phone. I remember that advertisement. And eventually we had--I remember once someone carrying around just in the '80s a phone in a briefcase. It was almost like a regular phone. It had two parts to it. It's huge. There was a huge battery. But that was a big modern invention. And then they got shrunk and shrunk and shrunk and shrunk, and then we got down to the size of something like a flip phone, a remnant of the Star Trek era that Motorola put out. Then we got to the cell phone, with iPhone, and now you can watch TV on it and so forth.

If you took the shale innovation and laid it next to all that innovation, where we are is, we just invented the touch tone. We haven't found different colors yet. So we are at a very early stage of the technological development of getting shale out of the ground. And what happened over the last several years is just a tremendous--going up that learning curve very quickly on cost. And there's more to learn-- how to do it in a way that people find more environmentally acceptable and so forth. But you can see from here, a lot of the fears of fracking water, getting back up--that's why geologists sort of dismiss it, and I wish they wouldn't because I think we should say, "We take this seriously, and here's why it's not an issue." But we have to take it seriously and explain to people why this is such an exciting area right now for natural gas, and that we can do it safely.

The other thing that comes up a lot is frankly water use for shale, especially in Pennsylvania and especially in New York. And what we have here is water that's used for all the fuels shown as millions of gallons per thousand of households for the generation of electricity. So this water used to generate power through various fuels. And you can see natural gas is the lowest. But I added to this one. The darker blue on the right hand side on top of natural gas is the water used for fracking. So you can see it's just a tiny sliver. Far, far more water is used when you're actually combusting the gas, and you can see that natural gas uses less water overall, even when you add that use for fracking, compared to every other fuel, including two renewables, biomass from waste and biomass from wood. And the only thing, of course, it's greater than is solar and wind, for which there's no water used. So that's just to put things in perspective for you.

Let's change gears now to power generation. And I just made a bullish story about natural gas, but now we're going to ignore natural gas. Now as a thought experiment, we're going to assume that no one builds another natural gas plant for the next 25 years. We're going to assume that no one builds a coal plant. We're going to assume that no one builds a nuclear plant for the next 25 years. But we're going to take growth into account. We're going to take the Census Bureau's estimate for population growth in the United States over the next 25 years, and take all their middle assumptions.

So when you look at migration rates, immigration rates, birth rates, death rates, whatever it is, since I'm not a demographer, just whatever data they had as your middle number, that's the one I chose here. It shows roughly a population growth of 16% by 2035. And I picked 2035, because that was President Obama's 80% by 2035 clean energy goal. We have 360 million people at that point. And we're also going to assume a 1% efficiency gain factored in. Right now we're using a little over 13,000 kilowatt hours per person in the United States. Bring that down to roughly 11,000, which is about a slightly less than a 1% efficiency gain. (That, by the way, is a reversal, because we've been using more and more electricity per person over the last 20 years not less. But let's say we can even it off and then decrease it, just so we can show an efficiency gain.) So what we need by 2035 is enough fuel to generate electricity for another 50 million people. So we're going to assume that those of us alive today who are going to be alive in 2035 are using this same mix we are right now, but everybody born between now and then, everybody who's immigrated into the United States between now and then, is using only renewables, and that's all that's built going forward. You've got to admit that's a pretty bullish assumption for renewables. So what happens?

Well, this chart shows our current mix of fuels for generating power in 2010. So if we take that thought experiment and move forward, what you get is, you get a bigger pie, because you've got more people and more power being used, and renewables has grown from 10% to 22%. Coal has shrunk from 48 to 41%, but it's still dominant. Natural gas has shrunk to 17%, and nuclear has shrunk to 19%. So renewable wins at everybody else's expense. But even with that bullish assumption, we have only 22% of power provided by renewables. And coal still dominates. So you say, "OK, but we know the Clean Air Act is about to be implemented in its final stages, and we have that all happening for the next four of five years, and we know that the plans are in place by many utilities to go from coal to gas." There are a lot of studies out on that, and you have to pick yours. I picked a very conservative one that said 15% of the coal plants over the next four to five years will either be shut down or in some way converted to natural gas. All right? So we're going to leave the rest of the fuel mix the same and just look at that. What happens when you do that is that, yes, natural gas does grow at the 24%, roughly a little bigger than what it is today. Renewables stay the same. Coal shrinks, but only to 35%. So coal still is the dominant fuel at 2035, when you have this kind of scenario. (If you don't like my numbers, by the way, do this yourself. It's not that hard. You're going to find it's very hard to get away from a pie that looks something like this. You've got to make some assumptions that you just have to swallow hard to believe.)

So what does this all mean? Well, one thing it means is that we need all our fuels. I don't see any way of getting away from this conclusion. I want to be convinced. I hope I can be convinced. Another way of looking at that thought experiment, by the way, is asking how you get, you either have an RPS that's 22% for all the states, or you have a price on carbon that is so heavy that it says, I'm not building any more gas, nuclear, I'm not building any more gas or coal plants, and nuclear stays the same. And we don't have that right now, although that 22% RPS isn't too far off.

The most confident thing I feel about right now is that letting the competitive market decide that fuel mix is the best way. I still don't see any mandates going forward that would be any better than what the market can produce. I do think we need appropriate regulation, and that includes appropriate fracking regulations, yes. We think the states should regulate fracking. There's going to be a period where you have to catch up, I think, to the industry. But that's happening now. A concern I have is that as renewables do grow, especially solar and wind, then the good operators are going to be challenged to maintain reliability, because my NERC friends tell me that once you get to the 20-25% range of variable power, you have to worry about how you provide the ancillary services to keep the lights at 60 hertz and the computers at 60 hertz so they function. And voltage in the appropriate range and so forth. And the markets are not competitive. One can argue that they have competitive elements, but the prices don't vary with supply and demand. So that's troubling, because my generator friends tell me, "Why would I build into that market? It's too small, and no one will pay me for it." So that's a concern of mine as we go forward.

The natural gas challenge is that we've got to address the public perception that somehow we're the bad actors here. That's on us. We have not done a good job of convincing the public of that, and we've let the natural gas opponents really have the upper hand. So it's something you'll probably see a little more action on by us in the future. And I think with that I'll stop and see if there are any clarifying questions.

Question: On the chart you showed about water usage. I'm assuming that what you were portraying was net water consumption, not total water circulated through the fracking process.

Speaker 2: No, that's the total water consumed during combustion and through the fracking process.

Question: Consumed.

Speaker 2: Consumed, not used.

Questions: So the volume of water required for the fracking process, much of which is presumably purportedly recycled, the volume of water used in the process is much greater …

Speaker 2: No, when we started fracking in 2005/6, we were recycling roughly, I don't know, I'm just saying 25%. It probably wasn't even that high. Now it's up to 45-50%, and we think we can get to close to 100%. That's the technology curve I'm assuming we're on. So over time, recycling is just going to make that better and better. But that number is so small now that even if it…I don't know the exact answer to your question, although I'll find out. But even if it's true that it's consumed, then it's still a small number, 3-5 million per well.

Question: We can talk off line. I'm not sure you're answering the question.

Speaker 2: OK, fine. We'll talk offline.

Speaker 3:

I was asked to talk specifically about the question of "If not nuclear, what is the role for shale gas?" So I'm going to do that. I have a similar diagram to Speaker 2. In fact, I kind of start where Speaker 2 leaves off.

So this is what I take as my touchstone, EIA's projections using the National Energy Modeling System (NEMS). These pie charts are from the Annual Energy Outlook (AEO) 2011 reference case for 2009, so coal dominates. You can see that wind is dominating in the renewables side, but the renewables are only this tiny sliver. And then by 2035, you've increased demand 22% for electricity, but you notice there's almost no change anywhere else. I think, I was thinking of analogy to what the moderator was saying about serial monogamy, and maybe this is "'til death do us part." We've got this generation mix we're just going to be stuck with for a long time, because you can see the renewables, even by 2035, are only 5.8% of the mix, and wind is still the dominant renewable. Nothing else much changes. It's basically growth in renewables at the expense of nuclear, without further policy.

So if we go through these fuels about what can step in to take this increased demand, if nuclear is not on the table, coal comes with very large risks. Just to remind you, coal mining disasters, mountain top removal, high conventional pollutants... And recently I've heard concerns about the ability to sequester large quantities of CO_2 in CCS. That's the hope, I think, of the coal folks, that they can use CCS, but there are seismic concerns that seem to be coming into the issue recently. Hydro and oil, as you saw, they're not factors. There's not going to be any additional hydro. Oil is not a factor in generating electricity. Nuclear, we're going to stipulate that there's not going to be any new nuclear any time soon. And then wind and solar--as Speaker 2 mentioned, we have intermittency, we have NIMBY, we have hooking them up to the grid, and all that ultimately is a matter of cost. So they're tough to rely on.

So the question is, can natural gas step in to meet our energy and environmental goals in the power sector? Can shale gas fill the bill?

The first question is, can shale gas lead to long-run price stability and lower prices for natural gas as well as electricity? So we looked at this. What we did is, we took the NEMS model's gas resource estimates and compared those with those of the Potential Gas Committee. Until recently, EIA had estimates of 270 to 300 and some TCF, for shale gas. We substituted the Potential Gas Committee's estimates of 616 TCF and ran a bunch of scenarios with NEMS.

Now, recently AEO has gotten very bullish on shale gas and has raised these estimates to 827. And we've done in-house work with our model, HAIKU, to look at that, and I'll show you that in a minute. And the bottom line is, we can keep natural gas prices low, even with big gains in natural gas demand.

Here we estimated supply and demand functions using NEMS. S1 is supply of natural gas under the old assumption of just 270 TCF, and S2 is when you're up to 616. And so we can get about a 25% increase in demand and still keep prices under $8.00 per million BTU. Currently, of course, they are in the $4.00, $3.50-4.00 range. But that's probably temporary.

I think the bigger question, which there's a lot of confusion around, is whether natural gas can be a bridge to a low carbon future. So we did work with NEMS on this as well, as well as on our in house model HAIKU.

First, I want to look at whether natural gas in fact is a lower carbon-equivalent fuel than coal is. This is from a little graph from Deutsche Bank. This is kind of the received wisdom. For natural gas, the CO2 equivalent over the life cycle is about 50% cleaner than coal. Then came the Cornell Study that Horvath, et. al. did. And basically what's at work here is, we have fugitive methane emissions associated with shale gas. And they focused on shale gas. And you multiply that times its global warming potential. And you add a bunch of the other fuel cycle elements in for natural gas, and then you compare that to coal on a CO2-equivalent basis. So I just want to focus on the fugitive methane and the GWP (global warming potential). In terms of the fugitive methane, one thing you hear industry say is, "Well, why would we let any emissions escape from our wells or our pipelines? Because that's money going out into the air." And the answer to that is, there is a cost/benefit test here. It's not economic to capture all fugitive emissions. And so the question for the companies is always, "Well, do I let that escape and don't worry about it? Or do I spend a lot of money to try to capture it?" So there's clearly some emissions. And I think the industry folks present will certainly agree.

The Cornell study itself is problematic, and a lot of folks in the industry have said this. There are basically five data points that address fugitive emissions, and they're all kind of low, except for this Haynesville figure. And that figure is based on a study cited in the paper that I and others who've been blogging about this can't find. I mean, we found the study, but we can't find the numbers. And I don't have an explanation for that. So I think you really should not take this study to heart. Horvath gets really startling estimates that coal is actually a cleaner fuel than shale gas by using a global warming potential over 20 years rather than 100 years, which is the more conventional approach. But this is a matter of scientific debate. And I think all this says is, this should stimulate further study and further close thinking about what's appropriate to do here.

So in our NEMS simulations, the bottom line is this. More abundant natural gas is not a bridge to a low carbon future unless you've got a policy to control carbon. Because what happens is, when this cheaper gas comes on the market, it's used more. It ends up lowing electricity prices and increasing electricity demand, and that increases CO2. In addition to that, the new gas doesn't only back out coal. It backs out nuclear and renewables. So the net effect, according to our simulations, is basically no change in CO2 by 2035. And for CO2, actually, it's no change over the entire analysis period, from 2010 to, in this analysis, 2030.

But with a climate policy, you get a lot of reductions in CO2, of course, with this cap-and-trade policy (basically Waxman-Markey). And of course, you get a lot more use of natural gas. Now, since there's a cap-and-trade policy that we modeled, you can't actually get reductions in CO2, because CO2's capped, and it will stay up at the cap. So what happens with cheaper gas is, it reduces the cost of meeting the cap. And we find that does in fact happen with cheaper gas--it saves you about a billion dollars over our analysis period, which actually isn't that much money. So we say, "Well, this is a narrow or a flimsy or a weak bridge to a low carbon future."

It would be stronger if we used the AEO 2011's new estimates. So there would be greater savings if we had a cap and trade program.

Now, we also did an analysis with HAIKU, which is our in-house power generation model. This time we used AEO 2011 natural gas prices. We looked at a baseline of 2010, which is about 300-and-some TCF, and then cheap natural gas, which was based on 827 TCF, and then we used cheap natural gas with a clean energy standard. The take home is basically the same story. The first bar here is at the AEO 2010 baseline. You get about 20% natural gas. If we have greater natural gas supply in the middle bar there, you can get up to 29% natural gas. So there's definitely something that happens, of course. And that's partly at the expense of coal, but partly at the expense of renewables and partly at the expense of nuclear. So the net effect on carbon dioxide emissions over the entire lifetime of the analysis to 2035 is basically this tiny change in the middle bar compared to the left hand bar for CO2. So again, you're not getting much. With the clean energy standard, of course, you get big reductions in carbon. And you get more natural gas. But it's not because of the cheap gas.

So I want to close by talking a little bit about shale gas risks. And the big study at the moment is the Duke study. Now, what the Duke study did was, they actually monitored water wells at various distance from drilling sites, shale gas drilling and production wells. And what they found was that the wells that are within a kilometer of the drilling site had high levels of methane, and the ones that are further from that site had very low or zero levels of methane. And also, they were able to rule out any fluids migrations--any migrations of fracking fluid upwards, as Speaker 2 was saying.

This is the key diagram from the study. The little dots there, their water well is within a kilometer of the drilling sites, which were in Northeastern Pennsylvania, in the Marcellus shale. They have the high methane readings, and then here they show all the wells that they monitored that are greater than 1,000 meters away, and they have very low or zero methane readings, except for that one little diamond there in the gray.

So this is, at first blush, pretty damning. The industry says, "Well, the Marcellus shale, it's full of Swiss cheese up there in Northeastern Pennsylvania, and there's methane leaking all over the place, and there's probably a lot of methane in those wells before the drilling even started." Well, that may be the case. But if it's pervasive like that, then we would expect some of those diamonds to be high as well. So in that case, it's kind of damning. But then there's this. What are these dots doing there [dots that show low concentrations of methane]? These are the ones that are water wells very close to the shale gas wells. But they have very low readings. So what's going on? Well, the fact is, we just don't know what's going on. And there's a lot of possibilities.

So the fact is that there's a lot that's not understood from this study. The fact is, we don't have baseline readings, which could really nail this problem down. And we need them. And the other thing about this study is that the depth of the methane that they identified in the wells is not identified. They know it's not from biogenic sources, at least not within our lifetimes. And that it is thermogenic, meaning that it came from deeper in the ground. But they don't know how deep. So they don't know if the methane came from production wells all the way at the bottom, or it came from pools somewhat higher or a lot higher that were cut out, or came up bore holes, or who knows.

So there's a lot more that has to be known. So the only thing that I would say here is that industry should get on board here, voluntarily--don't even wait for the states--and volunteer to take baseline data of all drinking water wells within a kilometer, or maybe further away, before they drill any new wells. Have third-party audits on this. The industry could agree to pay liabilities that occur to the wells that sort of check clean. They could get on top of this.

And so in conclusion, I would say overall, we're very lucky to be able to obtain this cheap shale gas, and the technological revolution that made that possible many years ago, that was then applied here, is a wonderful thing for the country. But we've got to get on top of these risks, both the ones that the experts tell us are there, which are kind of conventional risks, and the perceived risks that the public has.

I think industry is way behind the arc of public opinion, as Speaker 2 mentioned, and some really big mistakes as well have been made by the industry in trying to control these risks. Like selling fracking flow back to companies to salt their roads with. This was not a smart thing to do. The regulators are way behind in regulating. We've heard that Pennsylvania took mine inspectors away to regulate shale gas drilling. So you know, this is not going to be a good strategy. But there isn't the expertise available. And finally the scientists, as I've suggested here, are way behind on their research. And these recent studies, they're coming out fast, but you've really got to take them all with a grain of salt, as it were, and not leap too quickly in either direction. Thank you.

Question: For the production cost model, what was the internal model you were using?

Speaker 3: It has production costs in it. It's a dynamic simulation model, forward-looking, makes investment decisions, covers the entire country and the NERC regions, uses model plans for production. So it's not as detailed as IPM, for instance, of, and it's not as technologically-driven as NEMS.

Question: But it's producing the incremental cost of what, of natural gas, or what?

Speaker 3: Oh, I see. Yes, for these runs, the model is only of power generation. So we took the natural gas prices in AEO 2011, and fed them into the model. So they're price paths over time. So in that work, we weren't making any independent estimates of what those natural gas prices would be.

Speaker 4:

Thank you. I'm going to use my 12-15 minutes to focus on making four key points, and I'm going to first tell you these four points, and then go a little deeper into each one of them.

First, the characteristics of the power generation business today is not different from the past several decades. The session description begins with the words, "Rarely has the future of electric generation seemed so uncertain and fraught with risk." Now, we agree, that's today's situation. But it has been that way--the business has been risky. It is about making risky decisions under uncertainty. And the second point I want to make is that the economics of the existing fleet, the coal fleet and the nuclear fleet, is very good. And we expect the majority of the coal fleet to survive the EPA rules and other matters. And we expect only a modest retirement this decade, much lower than other forecasts. Our current forecasts point to around 35 gigawatts, a little over 10%, lower than what I think Speaker 2 mentioned earlier, the low end of 15% over the next few years. And we also expect the nuclear fleet to be very resilient, and that Fukushima will have only marginal impact on the existing nuclear fleet, not a major impact. I'll explain more.

The third point I want to make is that for new build, it's an entirely different story. And gas dominates by a large margin, and nothing else comes close. I think this doesn't come as a surprise. But we do find that many people underestimate the cost gap between gas and nuclear and between gas and renewables. And we think that the cost gap is very wide, and it will be very difficult for policy to push for large-scale deployment of clean energy. And technology advancement will happen, but closing the gap is far away and is not going to happen this decade.

And the last point I want to make is that retail power prices is on the rise, even given cheap natural gas. And this is after two and a half decades of continuous decline in real retail power prices. And we expect this trend of increase in retail prices to continue throughout this decade and next. And under this kind of environment, a key job for both utility executives and policymakers and regulators is actually to manage the power price increases, and we think that the limit of power price increases will pace the deployment of clean technologies, and that policy will play a role but has its limit.

And with that, let me go into the individual points. The power business has always been risky, and this chart shows the capacity that came online every year by fuel type over the past 60 years. And let me point out a few interesting things. Back in the '70s, we built a lot of oil-fired generation, more 40 gigawatts of oil-fired generation, only to see oil prices go through the roof. So when the power plant came online, the price of oil was several times, and in some instances ten times the going rate in assumption. And these plants never ran as they were designed to. And in fact, we quickly squeezed oil out of power generation in the next decade. And also, in the '70s, most utilities wanted nuclear power. And most people saw nuclear power as the wave of the future. And little co-ops, not enough to develop a project, sued to participate, to have a share of investor-owned utilities' nuclear power projects. And we know what happened. We abandoned and canceled more units than we actually built. And the ones that were completed later suffer from high inflation, high interest rates, delays, changing regulations, and cost overruns. And many of them cost ten times the original estimate.

So it's been a risky business. And closer to the present, the first half of last decade, between 2000 and 2004, we built 244 gigawatts of gas-fired generation. And not much else. And this is not just competitive generators. Utilities did 30% of those 200 some gigawatts. So everybody built gas. And the conventional wisdom then was that gas will push out old coal, and it didn't. And the vast majority of the merchant generators lost their shirts, and the majority of them, again, went through bankruptcy.

So it's been the risky business, and as we look out today, we see many risks. Some we know today, and others we don't. And be prepared for surprises. And these surprises, I just want to bring up one other aspect, are not just on the fuel choice side. Demand forecasting is risky, too. This chart shows the utility forecast that we see as reported by NERC. So every year, each utility forecasts the next ten years' demand and report it to FERC, and FERC reports the consolidated results. And as you can tell, back in the mid '70s, utilities forecast ten years out peak demand to be around 700 gigawatts. As it turned out, by mid 1980s, peak demand was lower than 450. So the forecast error was more than half of the actual peak demand. It was huge. And that led to a huge overbuild and lots of financial suffering, and many companies had to suffer from disallowances, because the new plants, whatever type, were not used and useful.

We continue to make mistakes, and it took ten years to correct it. And so demand forecasting brings a lot of risk to the power generation business as well.

Let me move on to the second point. The existing fleet is very resilient economically. And this is because the electric power business is very capital intensive. It is the most capital intensive among all major industries, and as this chart indicates, it's at the very top. It measures how much capital it takes to earn one dollar of revenue. And for the power business, it's roughly three to one. All energy businesses are pretty capital intensive, as indicated by those red bars, but power is the top. Now, what does that mean? That means once you build the plant, you've spent most of the cost already. So once you build it, the capital, the bulk of the cost, is sunk. So whether it's going to run or be shut down is dictated by the going-forward cost, the operating cost, plus the cost it takes to upkeep. And we use that principle to make a judgment about how resilient the existing fleet is. And ten years ago, we forecast that the coal fleet will stay and won't be wiped out by gas, and that was true. And it's because it only took, back then, $20 per megawatt hour to run the coal plants. And the new combined-cycle gas would not be cheap enough to wipe it out. It is the same thing today, if you look at the coal operating cost, on average, around $30 per megawatt hour, and a good 60% of the coal plants actually run below $30 per megawatt hour. And if you look at the cheapest replacement, it is combined cycle gas, roughly at $70 per megawatt hour. So the headroom, you know, $70 minus $30 is $40 on average. Others have much narrower headroom, say $20, and even at $20, you can take a lot of heat. Putting on scrubbers uses $10-15 per megawatt hour. If you have to convert once-through cooling into closed loop, that's on average $5.00. SCR (selective catalytic reduction), another $5.00. So if you add them up and compare with the head room, our conclusion is that most of the coal plants can actually withstand the addition of capital investment, so again, our forecast is that we expect only around 35 gigawatts of coal plants will retire this decade.

And nuclear is even more resilient. If you look at the operating costs, it's on average $20 per megawatt hour. Again, $20 versus $70 of the replacement combined cycle gas gives nuclear a very thick headroom. Nuclear requires a lot more ongoing capital, and that headroom gives allowance for nuclear to withstand capital investment. Now we expect Fukushima to bring in new regulations, but based on our understanding of what the problem was and still is (it's not over yet), the US already has the framework for station blackout, for cooling redundancies, and so on and so forth. So we are expecting incremental regulations, more resilient backup, more rigorous checking and practice, rather than a brand-new framework. So we expect the existing nuclear fleet can withstand new regulations. And we do expect that some local issues will shut down some plants, but those have existed for some time in pre-Fukushima.

So just to wrap up this point, because the power business is very capital intensive, the capital-intensive type of existing plants are very resilient and it is very difficult economically to kick these plants into retirement.

Now, let me now switch to talking about new build, and that's a very different story. And the shale gas, it is a game changer. Both Speaker 2 and Speaker 3 talked about gas. Let me just add a little bit to it. Back in '09, a little more than a year ago, we did a play-by-play analysis of the shale gas and tar sands. And this is one of the examples to show how the new drilling techniques have affected the shale gas. So this is 17 large plays, with sub-plays, and we estimated each sub-play's full development cost, plus a 10% return, and lined them up so you can think about this as a gas supply curve, and this is primarily shale. And if you draw a line at $4.00 per million BTU, you can see we have 900 TCF below $4.00. And as a reference point, today's total consumption for gas, not just power, but total, is about 28 TCF. So this is more than 30 years' worth of gas supply at below $4.00 per dollar of MCF.

Now, there are environmental issues. We are expecting more stringent and new regulations. So in our outlook, we add a dollar, so our outlook for gas for the long term is $5.00 rather than four. And maybe people talk about, "Well, gas is cheap today, and gas is cheap tomorrow, but if something happens, like we begin to export LNG, and we begin to use a lot more gas, or natural gas vehicles, it's going to drive up the price." But for those who are economists, we know that when you have a flat supply curve, you can use a lot without driving up the price. And you really take something that lifts the entire curve up to actually drive up the price.

Internally, we have a lot of debates about what's the high price scenario, what will lift up the price, and we are hard pressed to find a sustained good reason. So that's a game changer. With our assumption of $5.00 gas, we put this chart together, which is the busbar, or the levelized cost of electricity for different technologies. And combined cycle gas is the most economic on the left, $70. And others don't come close. And coal, even without thinking about carbon, is higher than gas. But we did see that when gas price flared up, back in '05, after Katrina, and in '08, we did see substantial coal under planning got their permits and went under construction. In fact, we still have ten gigawatts of coal under construction today, and we're likely to end up with a total of 20 gigawatts just from the recent past in the next few years on coal. So we wouldn't completely write off coal. And nuclear is very expensive.

And this is modeled after the two projects that we think will get built and come online this decade. That's the Southern Company projects, both Westinghouse AP1000. And if everything goes right, it's on budget, it's going to cost, by our estimate, $125 per megawatt hour. And that is very, very high, compared to $70, and a huge gap. And if we use a carbon price to bridge that gap, it implies more than north of $100 per ton of carbon price. So it will have to take very strong policy to make nuclear economic.

You know those complex stories? If you look at onshore wind, if we don't consider all other aspects, just production, it's around $100. And this is with a 33% capacity factor. And if we layer in other costs, transmission, integration, it adds another $30-60. So in round numbers, it is more like $130-160 per megawatt hour for wind. Cost is coming down, but we don't see cost coming down that fast to get anywhere close to gas. And solar is even higher. We are seeing a lot more growth in solar just now, and over the next decade, because of the solar carved out as part of the RPS, but it is not economic.

So we think the economics, the gap between the wind options and the gas options will make policy very hard to push. And that is in part because we see power prices will continue to increase. This chart shows the real and nominal power prices in the past. In real terms, you can see that power prices enjoy a steady decline from early '80s until about mid last decade. And then fuel price increases drove power prices up. But over the past few years, we have counted a lot more capital investment increases, which we don't expect that to stop. And these came from many, many places, including environmental retrofits, smart grid investments, T&D investments, and so on and so forth. So power prices are diverging across the country, and the increases will be different, so it's hard to generalize. But on average, we expect the upward moving trend to continue for the next couple of decades in our forecast. So that makes it a very difficult environment for regulators and politicians to push policy-driven clean energy, which command a substantial premium, into the mix. And for management, the concern about power price increases will be an important factor which will pace the development and the build of clean technologies.

Now, since this subject is about fuel mix, I'm going to wrap up with just a quick snapshot of the fuel mix. The fuel mix varies. We used a lot of oil before. We squeezed it out. Nuclear went from zero to 20% rather quickly in 20 years. We've been adding renewables, that's the sliver on top, for more than two decades. It's been steady at 2%, but increasing pretty fast over the past few years, and now it's at 4%. And by the end of the decade, we expect that to expand to close to 8%. And if you look at what companies are doing, companies are meeting their renewable portfolio standards, and where capacity is needed, adding gas. So gas and renewables are dominating.

If you look at it from the fuel mix standpoint, it is not that bad. It actually improves our fuel diversity by the end of this decade. But as Speaker 3 pointed out, when we use a lot of gas, we stabilize the CO2 emissions, but we don't reduce them. And more than that, we don't develop tools that can move us to a clean technology, low carbon world. So if we look out, we see stabilization of CO2 because of gas pushing out some coal, and adding in renewables. But the concern is that we are not developing tools that can reach longer term carbon reduction goals.

Question: On the slide where you had the busbar cost, what were you assuming for capacity factors for the various technologies? Because the question was coming up. For the CT (combustion turbine), the capital cost was much higher than it was for combined cycle and for coal, but I'm assuming it's because you have it running at a much lower capacity factor.

Speaker 4: Yes. Briefly, CCGT is 85%, coal is 85%, nuclear 90%, CT 15%, wind 33% and CSP, I need to check, probably 60%. And the non-firm solar PV is 20%.

Question: Thank you.

Question: On the slide of retail costs increasing, can you just explain what is included in the retail prices? The all-in price to customer, including state programs, universal service and RPS? Or is that just the commodity portion?

Speaker 4: No, it's the retail all-in price, including where it is separated, the commodity generated portion. But it includes all the surcharges and wires charge and T&D.

Question: Clarifying question. On this chart, what's the timeframe for this?

Speaker 4: This is near term. This is now, and over the next few years.

Question: In regard to the question of projecting for nukes, were you looking at existing technology? Or were you looking at other nuke technologies that may be on the horizon for nuclear plants?

Speaker 4: Are you referring to the cost?

Question: Well, in calculating what the costs were for new nuclear, what they potentially are, were you looking at existing technologies? Were you looking at smaller nuclear units, for example, that are on the drawing board?

Speaker: This cost is based on the two projects that are going forward. And we can talk about the others later.

Question: Thanks. I'm just wondering, going back to that price slide, whether your projections go out into the long term and what they look like.

Speaker 4: We do. For long term, like 2020 and forward, we actually used scenarios. So it's not like a point of forecast. Just take nuclear as an example. If the projects go well here in the US, as well as in China, the two projects we are likely to build (and China is building four units already, with another dozen following). So if the techniques of modular construction are successful over there, it has the potential to cut costs. But it won't affect the US until post 2020. So we do have forecasts, but there's a story to go along with it.

Question: So I'm wondering, in particular, if you have a high gas price scenario and what impact that has.

Speaker 4: We do have one scenario with higher gas price. It is in the range of $6.00-7.00. As I said, we've been trying hard to find a high gas price scenario. But I'm talking about on average. We're not going to eliminate weather-driven price volatility, even with shale gas.

Question: So then what impact does that have on the price of electricity, say to 2020?

Speaker 4: Well, it adds to it.

Question: I understand. But have you quantified that?

Speaker 4: I have to check exactly how much. But with low gas prices, we see about 1% real price increase on average for this decade.

Question: On this chart, since you are including fuel, did you extrapolate over a certain time period what you think the different fuel prices will be to work them back into this bar chart? And how long a timeframe did you extrapolate?

Speaker 4: The life of each of these is different. For gas, 30 years, for nuclear, 60 years. With the exception of gas, we have a more precise long term forecast, and we used that forecast. And the other is more of a fixed term today, plus our average long term outlook.

Question: So with coal, you would have taken the life of the plant and worked in a coal cost?

Speaker 4: Yes.

Question: Normalized or inflation adjusted? When you said "coal costs this much on levelized cost?" Is that…

Speaker 4: These are levelized nominal. So these are all levelized. And there are some other versions that are normal, levelized real. And in just about all commissions and ISOs, people use levelized nominal. So that's why we use levelized nominal. But in some instances, levelized real can explain more.

Question: On the price slides, for the increase that you were projecting going forward, were you implying that that increase was mostly driven by non-energy components? Because you mentioned T&D and smart grid and things like that. Or was the increase driven primarily by the energy itself?

Speaker 4: There is a little bit of increase of energy because there's more gas in the mix. And closing down coal actually is costly, even though new gas is the cheapest. So there's a little bit of that. And the vast majority of that is capital investment.

Question: Related to non-energy?

Speaker 4: No, related to your new renewables. It's a bunch of things--scrubbers, smart grid, and also energy efficiency spending actually increased unit price.

Question: Just a quick question on the technology cost slide. The numbers that you're showing for PV. Is that a cost based on feed in at the transmission level, or at the distribution level? And if it's the latter, is it really appropriate to show those numbers on the same slide as busbar cost at the transmission level for other technologies?

Speaker 4: It is the utility-scale PV farms. These are not the small-scale household or commercial buildings. It is not fair. That's why we label it as non-firm for a variety of reasons. We have 20 other slides to show all the layers that you have to make to make the adjustments. So they're not comparable products. That's a very good point.

Question: I was actually getting at the wholesale versus retail comparison issue, not the issue of firm versus non-firm.

Speaker 4: Oh, OK. So all these are at wholesale level.

General Discussion:

Question: Just as a general question for the panel, but mostly directed toward Speaker 4 on her presentation, which by the way, is probably one of the best narratives of where we've been and where we're going that I've seen over the last several years. So I want to compliment you on that.

There's an elephant that's in the room here that we're not really talking about, and we've mentioned it, and that's coal. And we talked about shale gas and the fact that we're seeing forecasts for gas prices coming down in the $4.00-5.00 per million BTU range long term. But the coal/gas spread continues to narrow, and a lot of that is due to world coal markets. We're seeing a lot of coal exported to China, and in fact the Chinese, by some accounts, are paying as much as $5.00 per million BTUs on the delivered price of coal today.

And so when I think about the economics of the existing coal, and also the economics of new gas going forward, looking at busbar costs is one issue. But looking at how these units operate in electricity markets is a completely different issue, where they're actually looking at what they can make in energy margins on an hourly basis, and then if there's any capacity market construct that they can earn there. And so my question, primarily to Speaker 4, but then I'd like to get the reaction from the rest of the panel, is, what role does this coal/gas price spread play in a lot of your modeling about the future, and how is that really changing anything? Does that change the amount of coal that we're going to see going forward, because 35 gigawatts seems like a small number, given EPA regulations and the amount of investment that we're talking about?

Speaker 4: First of all, the 35 gigawatt estimate is based on unit-by-unit assessment, with the unit-by-unit coal price as input. We do see that, particularly for eastern coal, the cost will increase because the productivity has been in a decline, and the total coal use has peaked, and we don't see the coal companies really putting a lot of capital investment to improve that. And then also because of the depletion of the coal resources, particularly in the Appalachian region. But at the same time, we see that as companies put on scrubbers--we've seen a good 40 gigawatts over the past few years, and another 40 gigawatt plant, and that's a huge chunk off the total coal fleet of about 300 gigawatts--as you put on scrubbers, your flexibility in using coal increases substantially. So those that are using, say, Central Appalachian coal, the most expensive type of coal, which also is connected with the international markets and commands higher prices, you can switch to Illinois coal, and even some of the companies are now blending with Powder River Basin coal. So to your point about international connections, we only see the Appalachian, Central and North Appalachian coal with the kind of quality for international markets and that can cross over into the METCO market. That's much harder that the steam coal market.

And then we have seen substantial switching that took place in '09 from coal to gas, and a bulk of that has sustained through 2010 in this year as well. And those all go into the assumptions. But we do see that the coal to gas switching has reached its limit, given that the gas prices have reached $4.00 last year, and it's likely to be in that range this year again. But going forward, it's going more to the $5.00 range. Does that answer your question?

Speaker 2: I took your question differently, so if I took it wrong, you can just stop me, but I thought you were asking about what that does to the market itself. Because if instead of gas being the marginal price that's high, the marginal price is now with coal, and coal/wind sometimes, then you have no high marginal price. You've got two log prices. And what that does is make it less profitable. It's a challenge for, I think, independent generators to make money that way. What I think it does in the long run, though, is (and I'm not an electric expert, so if you jump all over me, do it nicely) it will expose, I think, market imperfections on the power side, because people are going to be finding ways to make money in that tough to make money world, and they'll figure out, "Wait. That's not a competitive market. We've got to change that." And they'll be trying to fix it through FERC or through the ISO or whatever.

Question: Actually, both of your responses answer my question. I'm just kind of interested in everybody's different take on it.

Speaker 3: Speaker 2, you said a little phrase, "and EPA regulations to come." But I think that's pretty important. Coal will be under a lot of pressure for NAAQS regulations and other Clean Air Act related regulations, maybe the tightening of NAAQS, because coal would be the dirtiest fuel, can eventually come around and affect this. So there are a lot of issues out there that will probably affect conventional pollutants, and the toxic pollutant control will probably affect coal more than gas.

Question: I come from a world where we still get integrated resource plans, and we had our most recent one come through in March, and gas came in second place. And it came in second place to energy efficiency. I notice Speaker 2 had a 1% assumption in his analysis, but my question is, in all your modeling, how do you see energy efficiency as a resource and as potentially meeting some of these future needs?

Speaker 2: I guess I'll start. Historically I saw no reason to use anything other than zero, or maybe even a positive number, because frankly, because of these things that I mentioned earlier. From a technology point of view, we just have a lot of them. My kids have a bunch of these. We're using more and more. The less that we use because of the recession--we're using on a per person basis in this country less--but I think that the bottom line is, what I find most missing from analysis in general, is demographics. I am amazed that nobody takes demographics into account--how many people we're going to have in this country when you do the analysis. And so you have to assume a 1% efficiency gain just to run even. OK?

So you've got to get above that to actually have reduction in fossil fuel burning. And I don't see the technology around to do that. I certainly don't see behavior around to do that, unless you have a recession. For the last five or seven years, we have not been using more on a per person basis. But I think that's just temporary.

Speaker 3: I guess my only response would be that at RFF and many universities, many economists, many behavioral psychologists and so on are, and you probably know about these things, are doing studies on how to resolve this energy efficiency paradox. And people call it efficiency gaps or energy efficiency paradox, because from an engineering perspective, it looks like people, including businesses, should be making all these investments to save energy, but they don't. And why is that? And so, for instance, we have a study to look at alternative labeling of appliances to see, in a controlled experiment, to see which types of labels do a better job at inducing energy savings than other types of labels. And I'm sure some of you here know about how, across the country, various utilities are engaged in pilot experiments to see what approaches you can take to reduce energy use--peak load pricing and others. So I'm hopeful that in a few years, the results of these studies that are going on in earnest will give us some keys as how to unlock these efficiency gains we think are around. There are regulatory barriers, as well, that have to be dealt with. But there are big behavioral issues that we don't quite understand.

Speaker 4: Let me offer a slightly different angle. We see opportunities for energy efficiency improvements, but it depends on how you use it, how you calculate it. In fact, I think people underestimate how much in efficiency gains we have accomplished. If you analyze the data (EIA actually has pretty good data on things), we've done very well in energy efficiency. This may surprise you. But if you look at per household consumption of electricity back in the '70s, seven key categories accounted for 91% of each household's consumption. And if you track those same seven categories (these are, you know, heating, cooling, lighting and so on, and refrigeration, of course) if you track the same category over time, per household consumption for the same categories actually declined, even though houses got much bigger. We use a lot more lights because of the bigger houses, and we have two refrigerators rather than one, and so on and so forth. Per household consumption in these categories declined by 10%. But the same seven categories that accounted for 91% earlier, by a few years ago became 43%, because of all these new things that roll in. It's the new uses that are propelling the growth. If you look at the same seven categories and look at efficiency improvements, for every one of them we improved at least 50%. And today's refrigerators, compared to back in the '70s, use a quarter of the electricity. We've done quite well. So more efficiency push and improvements is more following the trend. We have to do a lot of those to maintain the built-in efficiency in our demand increase. And in power demand, growth is pretty much looking at, are we going to continue to churn out new uses? If you look at natural gas, it has not had any new uses. So the residential, commercial use over decades is flat, because of efficiency overrides, more people, and so on. If you do the same thing for electricity, it looks exactly the same, actually declining even better than gas.

Question: Yeah, thanks Commissioner. I had a question for Speaker 4 and I guess Speaker 1. There are rumors that DOE's blue ribbon commission may recommend creation of a new entity to manage disposal of spent nuclear fuel, perhaps on the order of a federal corporation similar to TVA. And I'd be curious to know from both of you what you feel the best approach to the issue of spent nuclear fuel might be.

Speaker 1: I'm sorry, I cannot comment on this. I have personal opinions, but I cannot comment on this here.

Speaker 4: Just for clarification, are you talking about the risk of spent fuel pools? Or are you talking about longer term?

Question: Longer term.

Speaker 4: I think there's international consensus that deep geological storage is the way to go. That's what every country is planning. So I think the blue ribbon committee is in charge of figuring out how we get there. So I don't think I have comment beyond that. But I think that takes a long time. There could be some interim solutions, too. And one solution proposed by some people that seem to be sensible is that we can do interim above the ground dry cast storage, but managed by the government. Since DOE is legally responsible to take title of the spent fuel beginning 1998, it seems to us that would be a sensible way to do it is to begin to centralize the spent fuel while waiting for the longer term geological solution to be resolved.

Question: I could ask a number of questions, but I guess I want to put Speaker 2 and Speaker 3 a little bit on the spot. If you were to predict in five years how the fracking debate has evolved, what's your prognostication on that?

Speaker 2: That's just not fair. So five years from today, right?

Question: Right.

Speaker 2: Well, first of all, I don't see how the industry can do any worse than we have in the last five years. So it's got to go up from there. [LAUGHTER] I would say, you know, in discussions around the coffee table in the break, people were saying that neighbors talk about casing and fracking when they know nothing else about natural gas. That is, like, everyone knows about this now--I wouldn't say the whole country, but in many parts of the country. And I think the industry will figure out that that's an opportunity to educate and actually have people find out what's really going on. So we haven't figured that out yet, by the way. We're still reacting and making ad hominum attacks on people. That's our response a lot of times, is just saying, "Oh, he's from New York, what do you expect?" or whatever. [LAUGHTER]

I think we're coming around to the idea that maybe we should say to the public, if this is what the public wants to hear, "We take these allegations seriously. And we've worked on it. Here's what we know. Here's what we can tell you about that." And then politely explain why you can't get fracking fluids up two miles against gravity and into your water. And that's why there's no evidence that that's ever happened. So I think five years from now we'll be in much better shape. I don't think it will be a big issue.

I will say that (I think I can say this. I don't think he'd mind) Burt Kalisch, head of APGA (American Public Gas Association), two years ago gave a public speech where he said that in two years, the fracking issue will have gone away. And he readily admits today, that he was totally wrong. It's gotten worse. But you gave me five years, so I think by then we'll get our act together, and it will be much better.

Speaker 3: Well, I'm not going to get pinned down on this, either. But it will come back to haunt… But what I see is, there are some parallels between the public debate here and the one that we are having even less of, unfortunately, with deep water drilling. And I expect this is going to happen with the arctic drilling as well, about how we internalize risks to the environment from our increasingly far flung and deeper and riskier approaches to meeting our energy needs. And there are parallels in the public perception issues. There are differences as well, but I'd like to see some success that we would have in one of these areas be a template for other areas.

The oil spill commission came out with a lot of very sensible ideas for improving deep water drilling-- internalization of risks related to liability, related to making a safety case, putting that burden on the industry and off of the regulators, so the industry has to make that case to the regulators the way they do that in the UK and in Norway. Some of those ideas could be applied in the fracking area as well. And I was very hopeful when the commission report came out that there would be more movement on that. And I don't see much of it right now. And we're already moving now to look at exports or drilling in the Beaufort Sea. So I don't know if I'm optimistic or not about the future here.

I think that one big step, as I mentioned in my talk, is getting baseline data on drinking water well methane concentrations, and then doing some testing. And as soon as a well starts being drilled, you're testing all the time. And I think EPA's study of drinking water risks that was mandated by Congress, this won't be out until something like December of 2012. But they're planning on doing some field work in partnership with companies. So that could be very revealing, too. But things are happening so quickly. I mean, that's a problem--both bad things and good things. But I think eventually we'll get our hands around what these risks really are.

Speaker 2: And one more thing. I think we'll have websites in five years, where if a producer approaches you and wants to lease you land, you can go on a website and see what that producer's record has been and so forth. And I think you are getting towards more transparency, and I think the market will push the industry in that direction. I think that's a good thing.

Question: I was trying to think of a way to marry the two panels today, and the short version of the question is, what is a generator to do, whether it is competitive generators or rate based--but I want to give the panel a chance to put their thinking caps on, as if they were policymakers or in the solution business. Because this morning what we basically heard was (and "sustainability" is the word that comes up both times) but we heard that economically, the present hybrid markets may not be sustainable. This afternoon we heard that environmentally, there are issues with all the different fuels that may not be sustainable, each for different reasons. And then we've got sort of the lack of decision-making by a variety of agencies in federal and state governments, yet at the very time as Speaker 1 in the first session told us this morning, the EPA rules are already starting to impact decisions in the business world. The phrase "train wreck" is often used in the environmental context, and I don't mean to use it there and insult the railroads, but it just seems that looking at it from the standpoint of representing folks, and others around the room who do the same, we try to put private capital to work to address these issues… how do we get out of this mess that we're in, where we've got all this uncertainty and kind of identified a lot of problems? If you could put your thinking caps on as to what solutions you would offer this group and other groups to consider to kind of move forward, because the clock is ticking, and decisions are being made, even if that decision is not to invest, yet we know we need to make investments. You only get 30 seconds each to do it. [LAUGHTER] But do you have suggestions? Or is it, as someone said on the earlier panels, that we really have no choice but to kind of muddle through, and that's kind of what we're going to have to do.

Speaker 2: I'll take stab. You've heard my answer before, though, so you won't be surprised, but I'll share it with the others. I think the power buckets are going to have to change a bit, because I don't think that they're prepared for the future that we're talking about of more renewables, and I think that the notion that the ancillary services are just this tail on the dog is going to have to change. I think that's going to get more and more important. The generators are the ones, you know--and your membership, for instance--that will supply that service, and as we get more renewables, more variability, I don't think (all due respect to anybody in the room who may be working on technologies to store electricity) I don't see that happening in the next five or ten years. Those technologies are further away, and they're expensive.

So for the near term, I don't think that we're going to find a way to have those ancillary service markets more competitive as a revenue source for generators and utilities, so that there's a way to keep the lights on while we build the renewables. Because the renewables are going to grow no matter what. I think in anybody's book, to varying degrees, but renewables are, because of RPS or because of what happens on Capitol Hill here--we're going to have more. And I think that we're ignoring the one part of the market, the ancillary services, that could help that.

Speaker 4: Well, let me give my 30 second answer. For the longer term outlook, we use scenarios, and our base case scenario is "muddle through." We see a lot of issues with competitive power markets, including some of the things that we discussed. The panel discussed this in the morning, about New Jersey and others, and we do see that there's tendency for states to do what we think about as price discrimination.

One question we get from competitive generators "When will the market reach equilibrium, so the price actually pays for new build?" But there are tremendous incentives for the state to push that point forward by paying for new supply with contract, and then you never reach that point. So that is de facto transition, the wholesale power markets for long-term procurement into long-term contracts. So over the long run, you use contracts to procure new supply, and then the power pools become near term dispatch. So that's kind of our base case, muddle through.

Speaker 3: I have a two word answer. Carbon tax.

Moderator: I want to ask a question that I think builds a little bit on this last question. We're taking it kind of as a given that the only thing that will happen is investment in renewables, demand side, and gas generation. Is there a business model we can think of where somebody could commercially invest in base load nuclear? I mean, are there technologies coming? Or are we just ready to look at a future that goes all the way out as far as those charts went and say, "This is what's going to happen"? I mean, will we be building more non-gas base load in the country?

Speaker 4: Well, nuclear at this point is not economic. If I think about a couple of good stories for nuclear, they're farther out. If you look at worldwide, there's 65 gigawatts of new nuclear under construction, and almost half of it is in China. China is building four with another dozen entering into construction. And the construction technique, the so-called "modular construction" where you do a lot of the big pieces, you assemble it and test it offsite parallel, so you can substantially reduce the construction time, instead of building on site--if that's proven successful, it can cut costs, and there are cases in other industries, including the nuclear submarines and so on, that show that this kind of modular construction can cut costs by on the order of 30-40%. So if that can be accomplished and can cut the cost substantially, and if increased confidence and a greater number of suppliers drive down the cost, then, post 2020, we do have a scenario when nuclear becomes more economic, as consideration for non-carbon becomes more important, and as we face the retirement of the existing fleet.

Now, even if we extend all the 104 reactors by 20 years, we begin to see a cliff as we approach 2030, and the existing nuclear will have to retire. So maybe that will stimulate more build. Another possibility is small reactors, and I think three of them plan to file their design certification by the end of next year. But there's a long way to go. And we're not really convinced that the per-kilowatt cost of small reactors--these are light water reactors, or similar design, similar but not the same as in the large reactors--we are not convinced that the per-kilowatt cost is going to be lower than the large reactors. There's a slew of issues on licensing cost, because it takes just as long, and probably the same number of hours to review a small reactor, compared to a large reactor. And also the exclusion zone--the safety standards, I would assume, would be the same, but there's a question of whether for the small reactors, it does not require a similar ten mile exclusion zone. So there's a lot of issues there.

And if it's successful, it takes another five years to go through the design certification into the construction phase, so the earliest possibility time that US may build a small reactor is 2020. And the attraction of the small reactor is that the reactors are designed so that you can ship the reactors on rail, and there'd be a lot more manufacturing companies that can handle it and increase competition--so that could come, say, post 2025. So it's a long-term process, but that possibility exists.

Speaker 1: I'll just add a few relevant comments. The Commission, the NRC, has been informed that we may get the application for design certification of the M power reactor, which is one of the small reactors, later in the next calendar year. Originally it was supposed to be the first quarter. I believe it has moved. Yes, it has moved up to maybe later that year. And then, of course, it will go through the review process and address some policy issues, and of course the technical issues.

Another relevant point, I think, here is that even for existing reactors, as you probably know, the original license was for 40 years, but very large numbers of them have received their license extension for another 20 years. And there is very active research, sponsored by DOE and EPRI, on the so-called "beyond 60." So that will extend the life another 20 years for a total of 80 years, which of course will impact the economics.

And finally, on the small reactors, one argument that we hear that will affect cost is that if you want to produce 800 or 900 megawatts ultimately, using six units, you start building one, start collecting income, and then you build the second one, the third one, so you don't have to come up with the capital up front for all six units, which is very different, of course, from the current reactors, where you really have to put up the capital up front. So that is advertised as another benefit of the small modular reactors.

Question: I, too, would like to pick up on The previous questioner's interest in sort of marrying these two really excellent panels, and particularly thinking of this in relation to Speaker 4's presentation, but the question goes to everyone.

On one hand, I heard about these risks and said to myself, "You know, this is why we restructured this industry, to re-allocate those risks that would otherwise just be 100% borne by the customer to a more competitive system." That's why we did this all in the first place. So I say that on one hand and say, "Gee, maybe we accomplished something by doing that."

The flip side is, I am cognizant of the question this morning, which was, are these risks (sort of paraphrasing) but are these risks so great that we can't get things built, that the market is too complicated? And that we cannot succeed in at least getting new entry with this level of risk allocation that we just embraced in restructuring?

So I'd like to get people's thoughts. It's sort of a conundrum in my own mind. I'd like to get people's thoughts on that.

Speaker 4: Let me provide a couple of thoughts. You have a complex system of federal regulations and state regulations as well. Even in markets that are very competitive, like in ERCOT, you also have co-ops and munis embedded in the competitive markets that are building based on fundamentally different frameworks. So competitive markets have not been operating in the way that, when you have excess capacity, it goes down to marginal production cost, but as you use up excess capacity price goes up to the replacement level, and then it becomes economic to build new plants and give the price signal. Instead, what you see is that you have a couple of experiences of price spikes, but it's very fast to put in peakers and so on, and also, well to pick peakers, and so the first experience is that you get one or two years of feast, followed by a long four, five, six years of famine--of new plants living off marginal production costs. So so far the experience is that if you are a merchant generator, you simply cannot survive. And that is for regular plants, like combined cycle plants.

Question: So what does that do to the whole risk allocation we were trying to achieve in restructuring, I guess that is sort of the big --

Speaker 4: Well, I think you shift it onto these competitive generators, but the market--I wouldn't say just the market design--but it holds the baggage of the historical structure of the industry. It is not really providing enough returns for the merchant generators to survive. And if you look at clean energy, like nuclear power, it is far out of the money, and it is a ten-year effort if everything goes smoothly from the beginning of developing the project to putting a project into operations. And over the ten-year period, you are going to have at least one recession, just based on historical records, a dip in gas prices, and you are going to have higher interest rates and inflation that can shake the confidence of nuclear projects. So, in a competitive market not having the assurance of customers and having to sustain through ups and downs of the economy or other things that threaten your project for the long haul, it does not look viable.

Actually, even with cap-and-trade, nuclear has to rely on very high carbon price outlook farther out for a long stretch of the time. To have that kind of confidence that the policy will stick to it and will not create new relief valves and drop the price is not realistic. It will be interesting to see what the UK ends up doing, beginning to put carbon price floors and looking to feed-in tariffs and other ways to support nuclear build, because they have decided not to give direct government subsidies, but rather to reform their competitive market for their clean energy development. So I would say that's a good place to see what they are going to do, and whether they can be successful.

And renewable is the same thing. It's out of money. So how does it play in competitive markets? And there's also a lot of question about whether it's fair to the fossil generators to have heavily government subsidized energy entering the market and taking up their shares.

Speaker 2: Could you expand on that, please? Heavily subsidized in what way?

Speaker 4: Well, you have, say, wind getting the production tax credit. And without that, they wouldn't be in the market to take the energy share of your business, if you're on the combined cycle gas. So you are seeing your energy revenues decline because of increasing renewables in your region. And so the question is, is that fair? It is government subsidized. And if you look at the Pacific Northwest, it's a bumper year for hydro. And companies in PBA have had to curtail wind, for example, because of fish life issues, rather than spill water. Now, the wind generators are saying, "Well, we are willing take a negative price, because otherwise we don't get that production tax credit." So that's the problem. You have a government subsidized entity that's taking up the business share of other competitive business, that live and die off how much you actually sell.

Speaker 2: Well, I asked the question because I don't remember much of my schooling, but I had an economics professor who said, "If you have a competitive market that doesn't produce enough supply for the market, it's not a competitive market." And so when I look at what we've done in restructuring, we have not produced a competitive market, sort of on the face of it, because it doesn't seem to be working that way, the way we expect a competitive market to work. And I think the way we structure our social policy with tax credits--for all the fuels, not just wind and solar, but natural gas and oil and coal and everything else--it doesn't seem to have produced a level playing field. And it's not a case where you can say it's this or that fuel. I think it's across the board. So I think the combination of the way that Congress has acted since the early 1900s, where my sector got its manufacturing tax credit, because gas and oil production were considered manufacturing activities, which we get today, to the kind of tax credits that wind and solar get today, or subsidies out of the Treasury, is as distorting a market enough to where we're not sure what kind of market we have. But I'm pretty sure it's not competitive.

Speaker 3: This, I guess, makes me think about a bit of irony here. Before there was restructuring, there was a big movement among the electric utilities sector on the social cost of energy to remember the environmental adders, and all of that. And then that got completely supplanted by the industry turning towards restructuring, where in Europe they kept up their work through DG 12, I think it was, and it spread out now to the point where they're doing full social costing studies. I don't know how much influence it's having, but the idea, if you remember, was to get a level playing field for investment, at least, if not operating a fully level playing field, but at least to make investment decisions based on social cost. And I think doing that work, again, looking at both the subsidy side and the risk side, could be a useful bit of research to guide attempts at appropriately internalizing risk and setting appropriate public policy.

Moderator: Whereas this morning's panel made me feel like there was quite a high onus on FERC to solve all the problems, this prognostication is making me feel like it doesn't really matter if FERC's lights come back on or not. [LAUGHTER]

Question: First, just a quick comment, and then a question. It's probably not helpful to get into a numbers debate, but on Speaker 4's cost slide, for the levelized cost, on the PV and solar numbers, I just have to point out that they seem to be significantly higher by orders of magnitude than most other studies that are out there. And these are credible entities. So I wanted to raise that point just because it was so obviously different than what people are using now.

And while my battery was still alive, I looked things up—for LCOE (levelized cost of electricity) out of Lazard last year it was looking at $90-190 a megawatt hour, and that's across all technologies for solar. And that was in 2010, which is really 2009 numbers. So since 2009, hardware costs in solar have come down dramatically, and they'll probably continue to do so, at least in the short term, given the changes in Europe and the oversupply situation, which the US will benefit from, at least from a hardware cost perspective in the next two years. So it's an important factor difference that I wanted to point out.

And then just a question, back to the broader conversation. A couple of people mentioned or observed that we're muddling through on policy, and I think that that's true. And to some extent, that's a loss for the US, because there's quite a bit going on in China and India in terms of development and investment, particularly on the renewables side. I mean, that's a loss for the US.

But we're not completely muddling through. I work at the state level, and where the federal government isn't necessarily acting, many state governments are. Not at the same level, but last year in Arizona, there was a bill to actually include nuclear in the RPS, the clean energy standard, to help boost nuclear investment in Arizona. Now, that particular piece of legislation didn't pass, but you do see many state legislators and state agencies actually pushing, not only RPSes, but different scenarios to actually promote policies. And that's a good thing, from one perspective. It's a difficult thing, because obviously you'll end up with a number of different policies across the US.

So I wondered if any of you could comment on your experience of what's going on at the state level. Because our interests are certainly focused much more there right now.

Speaker 4: First of all, on the solar cost, I'll be happy to compare notes. Our PV does include a 60% reduction over the past couple of years, but we've seen that that's run its course, and now it's stable.

And on your other question, yes, we do see states in RPSes in some states expanding the definition of RPS. That's why we are forecasting renewables going from 4% to 8%. We have observed at the state level supporting nuclear, for the two projects that we forecast will go forward, and will be completed by 2020, a very, very big driver is that Georgia and South Carolina passed legislation supporting quick and rate base, so as you license and build the plan, you recoup the financing cost and regulatory procedure to approve the plan and estimated cost in all those. And both companies have raised rates to cover their nuclear power plants already, even though they have not received the license. So we see states as very important.

We also see a few other states that are moving in that direction, approving or moving towards approving recovery of early site permit costs and so on for nuclear power in there. We see it as a good thing that some states and some companies are spending money on the nuclear option. It is out of the money for now, but we think developing the option is a smart move. Now, for RPSes, we did do a case of the so called "clean energy, clean electricity portfolio," and they include nuclear in there, actually, at the federal level. That's one of the schemes that people are talking about. But if we don't really add carve outs and so on, it doesn't help that much for nuclear. It helps a little bit. It gives some states that already have the site and have the intention to do a reason to do it. But it is not a big boost if you include nuclear into, say, 20% CES by 2020. It actually helped wind a lot post-2020 after the state RPSes kind of run their course through 2020. So in a nutshell, we do see the states as a very important driver now, and also in the future.

Question: Yeah, just a quick comment on that. Beyond the RPSes and renewables, we see states becoming more active in terms of the gas scenario in Pennsylvania, in terms of ways to promote investment in other fuels and other energy resources, even beyond the renewables, the states taking a much more active role.

Speaker 3: Yes, I would say I'm all for states being the laboratories through various pilot projects and experimentation at the state level. But a lot of these markets you are in are related across the country, and are interconnected. There can be a welfare loss over the long period. And the federal government needs to step up--not in the fracking area and the shale gas area, I think this is mainly a state level issue. But the federal government should be supporting that more than it is with model standards, and the DOI on their own lands, where they have control over and could set precedent for how you regulate fracking on federal lands, could do more. At the moment, they're only running around the country listening to folks, which is a good thing. But they've been sitting for months and months while the world is going mad. And I'd like to see the Feds, too, more in there. And then there's California for AB 32 on carbon cap and trade. So we'll see how that plays out.

Speaker 2: And would you see the states taking a bigger role than the federal government going forward in pretty much all forms of energy? Especially in natural gas, but I think one are that has not gotten mentioned, except maybe superficially, is on a clean energy standard area. I have yet to see anybody define clean energy in a way where people have glommed on and said, "Yes, that's a good way of defining it." I think in the laboratory we have built in this country of 50 states just trying various things out, I see the states playing a bigger role in that area than the federal government, because if you notice, at the federal government level on Capitol Hill, the piece that came out of the Senate, that was to kind of kick start the clean energy standard. I've never seen something that carries so many seeds of its own destruction within the very thing itself, because it asks so many questions at the end. You feel like there's no hope for a clean energy standard. So I think it's going to fall to the states to take the lead. And I think it's appropriate at this point. That's what this country is good at.

Speaker 4: I would add that power technology is global, but the resources are very local, particularly when it comes to renewables. And also acceptance of nuclear power. So it makes sense that at the more local level that people decide on what they want, what kind of risk they want to take.

Question: I just have simple predictive question, since we've been asking the panel for predictions all day. And it's hard to resist this unique blend of talent. Predict what will come first: groundbreaking for construction of a new nuclear power plant in the United States, or groundbreaking for an Alaska natural gas pipeline? [LAUGHTER]

Speaker 2: Nukes. Nukes first.

Speaker 3: Yes, I think I'd agree with that, too, because shale gas is so cheap.

Speaker 4: Yeah, I'll go with nuclear.

Moderator: I'm sworn to support the national gas pipeline under the Alaska…whatever the special act is. [LAUGHTER]

Speaker 3: 1977.

Question: You're going to give that answer to the Congress?

Moderator: No, I believe I did when Senator Murkowski asked me, "Will you uphold the thus and such?" I forget the name of the act. The Alaska Natural Gas Pipeline Act, or whatever. I said, "Yes, I will uphold." [LAUGHTER]

Question: Good answer.

Question: I have another prediction question. And it has to do with the price slide that you had, Speaker 3, slide number eight, I think. And I'm reading that as saying that there's a regulatory risk to this whole shale gas debate that we've been talking about. And that at 2030, one way to measure that might be the price of natural gas varying somewhere between like $7-10. So if I'm reading that right--tell me if I'm reading that right--but if I am, do you have other scenarios, or better yet, an expected value somewhere in there that would help guide investment decisions today?

Speaker 3: No, I don't. I don't think you're reading it exactly right. When I drew this arrow here, I was just drawing that from a known point on the supply curve, S1, for the old gas resource estimates, to another known point, with a higher gas estimate, on S2. So from number three to number seven. I wasn't saying that we have a forecast of $8.00, though. And in fact, again, as I mentioned, if we did this again with the latest NEMS model for 2011, there would be an S3 that would be flatter and below S2, and then we would have to estimate exactly where that comes in. And it might very well come in around $5.00 in 2030 or 2035. But I'm not making any predictions for that.

Question: I'll put my question in the context of the topic of the panel, which is that it may be another nail in the coffin for new nuclear, but we heard this morning, and also I completely agree that the value, if not necessarily the pricing, (although looking at the pricing as well) of ancillary services will have to become a more significant share of revenue requirements for generators. In fact, we're advising the UK government on their market reform, and they're looking at ancillary services going from something like 4-5% of power sector revenues today, to 20-30% of power sector revenues by 2030.

If we think about this morning's discussion, that implies a revenue model for dispatchable generators, where the revenues that they can expect to receive from capacity might come to 70-75% of what they would actually need in order to justify the investment in new capacity. The rest would come from the ancillary services market, which if you follow that logic further would say that that market structure, if it does evolve, as I think most of us would say it should, would drive a shift in the investment in new dispatchable capacity away from capacity that cannot participate in some or all of those ancillary services markets, and towards capacity that is firm capacity, dispatch capacity, that could participate in some or all of those ancillary services markets.

And unless there's something new about nuclear technology coming down the road that I'm not aware of, and I used to work in the nuclear industry, that would further deprive nuclear of badly needed capacity revenues that they're desperately seeking to get in some of these markets. So both for nuclear and more broadly, do you agree with that view of how revenue models are likely to develop for new investment and dispatchable capacity? Or do you see it differently?

Moderator: Well, I'll take a stab and say I'm inclined to think ancillary services markets will be more important in the future than they've been in the past. I mean, we used to think there was this really simple product called electricity that was all bundled--all the generation, the distribution, transmission--and we've stretched it out into so many components and have markets for reactive power and things that used to not even be a market product. And I think a lot of these factors lead to ancillary services just having a bigger profile…But I'll invite my esteemed panel here.

Speaker 2: Well, I'll start. You commented on nuclear. I think unless the technology is going to change, it doesn't really feed into the ancillary service market very well. They don't provide that kind of service. I will say that thinking about the future, how we market that bundle, because the moderator is right, we have sliced and diced--I saw one paper that had 28 different ancillary services, which I've just got to say is, as an engineer, is ridiculous. That's just dividing things too finely--and we're trying to have markets for them all. And I think what we may end up with is (and I realize this is all totally off the record, which is good, because I'm making this up) [LAUGHTER] but it just seems to me, well, when you have a membership you just can't make things up. What makes sense is to have market structure around what people can do.

So if people can ramp up or ramp down certain rates, that's what the market is. You have a price around that. Can you respond to that? Then you can create that into a market. So you're providing a service of going up or going down. It's that simple. Then you have to rate show fast you go up or down. So maybe you get four markets. But you can limit that to a finite set that I think we can construct a competitive market around, where you can have supply and demand do its thing. And I think that may be where we're going in the future.

Speaker 4: I kind of have a different angle on this one. I think a lot of people want competitive markets for lower rates. Many in this room like price signals and so on, myself included. I'm an economist. But a lot of people bought into competition, because at the time, when the embedded utility cost back in the '80s and early '90s--because we overbuilt, base load was so high, and the new combined cycle was very low--so the average cost, the embedded cost, was much higher than the marginal new cost, and people wanted access to that right away. It's really cost driven. You want lower costs. And I'm not sure loading on more layers of products and charging more, most people would agree and go with it, and in fact, we see indications that states and others are trying to get around even the capacity market and not pay for it, because it's a rent issue. You're already there. Why do we all of a sudden pay you that much more compared to two years ago or three years ago? So I sense resistance of people paying another layer of cost.

Question: I think the model I was suggesting was that in a competitive market, the revenues that generators receive for ancillary services would end up backing out what they could receive in a competitive market for just raw firm capacity, dispatchable capacity, which is the way it should work. So these additional products and markets for those products and the payments you receive for those, in a competitive market, would not be layered on top of the existing value of capacity. They would in fact displace some of the existing value of raw capacity.

Session Three.

Complementing Wind and Solar: Is the Natural Gas Infrastructure up to the Job?

The intermittent nature of wind and solar energy production has been the subject of considerable discussion regarding the expansion and operation of the High Voltage Transmission Grid and how to complement supply during the "down time" for wind and sun. Since battery technology is still rather primitive, demand response evolving, and nuclear and coal plants are designed for base load and not ramping up and down, the assumption had been that natural gas thermal plants would complete the energy supply. That assumption presumes that infrastructure in terms of pipeline capacity and generation capabilities would be in place. Recent controversies, much of which were captured in reports sponsored by the INGAA Foundation and the Gas Technology Institute, have called that assumption into question. What level of pipeline infrastructure is needed to complement intermittent generation without sacrificing service to other users, and what, if anything, is currently lacking? How do we plan and coordinate between the power sector (particularly, although not exclusively, the renewable energy producers) to make certain that all resources necessary for supply are in place? What contractual arrangements need to be in place? Who will bear the costs of assuring the requisite infrastructure and how should we allocate those costs? Should there be special tariffs for complementary generation that specifically reflect the costs associated with ramping up and down?

Speaker 1:

Good morning. It's good to be here, back at HEPG where I have come a number of times and really always appreciated the thought leadership here around electricity market design.

Interesting discussion yesterday. I thought it was very good, very insightful—a lot of talk about gas or wind, or gas versus wind, or gas and wind. I think Speaker 2 from Session Two and I really would say a lot of the same things. He says, "Look at all this natural gas from fracking." I might just shift the emphasis a little bit and say, "Look at all this fracking gas!" What are we going to do with all this?

But I think the points about "serial monogamy" from the Session Two moderator are right on. I think we are looking at a dash for gas. And so the issue whether to have some level of diversity or none. That's really the policy question.

So let me talk a little bit about wind's status and then get into the issues of integration and what the implications of integration of renewables may be for gas generators and gas pipelines.

First, in terms of where wind stands, the technology continues to improve, even just in the last couple years. Costs have come down 20% or so on wind turbines. And the technology is improving. Larger swept areas are reducing or increasing the capacity factors. But as the yesterday afternoon panel put it, it's all about natural gas right now. And so it's a tough market out there for anybody.

I was glad that Speaker 2 from Session Two said that renewables are going to expand dramatically under any scenario. I'm glad he's so confident about that. I do think, again, that there is a serious policy question about whether it's all gas or whether there is a little bit of diversity.

The typical turbine being installed today produces 15 times more power than the typical turbine installed in 1990. This shows the size increasing, and the size is the main source of that greater efficiency. If you blinked, you missed it, but a year or so ago, wind was lower cost than every other new generation source. But that's not the case now, with all the shale finds.

We do think we are very cost competitive with other conventional resources now. This costs I'm showing include 2.2 cents for the production tax credit.

There was some discussion yesterday about the cost of wind power. I think Speaker 4 in Session Two had us at over $100 dollars a megawatt hour. If you look at FERC's quarterly market reports, which report actual contracts, the average is right around five or six cents, or $50 to $60 dollars. And so you could say, well, that's the price. If you add in 2.2 cents, then maybe it's seven cents. So you could see where that fits on this graph. So I think in terms of Speaker 4 from Session Two's overall conclusion, yes, gas is the one to beat. But I don't think we're that far out of the picture. I think we're close enough. And I think a little policy push will get us closer, so that, again, there's a little bit of diversity in the power system, and not just gas going forward.

We have demonstrated our ability to deploy at a large scale; 35% of the new installed generation capacity in the last four years was wind. But even with that, looking backwards over the last seven years, natural gas's market share has increased seven points and renewables only two. So there's been a lot of talk about renewables. And we've been very pleased with our steady development. And in this long-lived asset and capital intensive market, we're happy to take 20 years to go from zero to 20% like nuclear did. That's just fine. We're not saying we're trying to be 100%. And we agree with the general theme yesterday of, "it's going to be a diverse portfolio no matter what," just because power plants stick around for a very, very long time. So again, we think a gradual increase to diversify the portfolio would work fine. But I think it's interesting to see here that even with all the talk about renewables, gas has been the one that has grown so much.

So let me talk about some integration. There are a few key points that I think are not obvious if you don't live this every day. First of all, there are a lot of "Electric Grid 101" issues going on out there--other than onsite PV, most renewables are on the grid. So when the wind doesn't blow, what do you do? The answer is, you ramp up other generators, or demand response, or other sources of flexibility. And when you look at how the grid operates, then it's a lot easier to see how you integrate renewables.

Another key point is, what is the variability? The time scale is extremely important. Most of the people here understand that instantaneous products like regulation are expensive relative to longer-term products, even just hourly or two-hour products. But look at the variability here. Even for Texas, with 15,000 megawatts of wind penetration, over a minute the variability is 6.5 megawatts. That is very little variability in the short timeframes.

Yes, over an hour, you can have some serious issues. In Texas, they can have 1,000 megawatts of variation over a couple hours, and what the grid operators have to worry about is the ramp. How do you get the ramp over an hour or two?

But if you look at this next slide (and most people here are well familiar with these figures), the costs of the instantaneous products are very high, well over ten times the cost the hour or two-hour products.

You know, with respect to integration, it's not a reliability issue with the levels of penetration we're talking about; it's a cost issue. But the costs are, again, a lot less for the hour or two-hour timeframe.

In terms of studying the impacts of integrating renewables (and I think the INGAA ICF study will be talked about here), there have been a couple of dozen studies in the U.S. and a couple dozen in Europe on integrating renewables. And these are some of the general methods that have been accepted by the utilities. I'm talking about utility studies, when they're looking at their own system and how to integrate renewables under their own system. You have to account for the aggregate variability and uncertainty on the power system. So you don't firm the wind. OK? You don't have to have a backup onsite to back up the wind any more than you have to have backup onsite, standby power, for nuclear, coal, gas, or anything else. Right? It's a system need. What we're trying to do is balance the power system and keep aggregate generation equal to aggregate load.

Now, you can do studies. And I would argue the ICF study did this. I would argue a couple of the Carnegie Mellon studies did this, where you look at the cost of trying to balance just the wind. Well, you get a very high number in terms of reserves and in terms of the cost. But that's not what utilities do. They know how to operate their system, and they are trying to aggregate or balance the aggregate variability.

The numbers do vary if you look at the studies. We can send you a list of about 15 studies that show the reserve needs for integrating wind. It's sort of 3-15% reserves from these utility studies in the U.S., whereas the INGAA ICF study is 30%. So it's about a third of what the INGAA ICF study says. But it does vary. And 3-15% is a wide range in terms of reserves needed. And that's because we have a wide range of operating systems in the U.S., from the large RTOs which are the optimal structure, to the smallest balancing areas that may or may not have other flexible resources on the system, that may or may not coordinate with neighboring balancing areas, etc. So those things really matter a lot.

The other thing about wind variability is that it is much less over large areas. So the more we operate as large regions, the less variability we have. You can see that, if you get out 500 kilometers, like a medium-sized ISO/RTO, there's only a .2 correlation coefficient between the different wind plants. So that's in support of the concept that the wind is always blowing somewhere. And if it's not blowing one place, it's blowing somewhere else. That's not always true, but the concept is pretty robust.

So utility studies show in terms of the cost, it's $3 to $5 dollars a megawatt hour on the right side there for integrating wind. So you could think of that if you wanted to. And the figures given by Speaker 4 of Session Two had a cost for integration. They said $30 to $60 dollars a megawatt hour. This shows that for the integration part of the cost, it's $3 to $5 dollars a megawatt hour.

And again, there was discussion yesterday about concerns about integrating a lot of renewables when you get to, say, 20%. Well, OK. Twenty years from now, let's talk about that. We're not anywhere near that now. Even the high numbers here, Iowa and North Dakota, are part of the MISO grid, a 15-state grid. So the penetration levels for the MISO grid are well under 10%, and, of course, 2% nationally. So we're really not reaching these high levels yet. And in Europe, they are reaching those levels, and yet they are operating perfectly reliably. And in fact, these points below show why it's even harder for them to do it, but they are figuring it out.

So sometimes you get the sense that, you know, renewables are going to have to pay for all the integration charges, and then, you know, other people come along and say, "Hey, well, that's a nice new revenue source. Let's get a piece of that, and let's figure out all the implications that may be with renewable integration and try to get a piece of the revenues of that." We need to put this into context. Dealing with variability from a distributed resource over a wide area, over, say, an hour's timeframe, is not necessarily more costly, and it doesn't necessarily have more reliability impact than dealing with a large central station instantaneous outage. OK? And not to criticize other resources, but if you're taking 1,000 megawatts offline instantaneously, that's a lot of very expensive product that you need to have on the system, and you have to have it 24/7. So you could add this up around the country and get almost $2 billion dollars a year from that.

People aren't talking about, you know, "let's do coal integration charges. Let's do nuclear integration charges." You know? We'd argue from a discrimination standpoint that you shouldn't do renewable integration charges if you don't do the others.

Here are some particular generation units in one system. The cost impacts [of integration] are over $4 dollars a megawatt hour. So, again, on the order of the $3 to $5 dollars for wind, so, you know, wind is not necessarily out of line with where the other generations are in terms of integration charges.

So let's talk about improving the situation for everybody. Let's talk about improving reliability and efficiency and renewable energy integration.

Let me start with short dispatch intervals. If you think about variability--and again, you're trying to deal with variability over, say, an hour's timeframe--if you're the grid operator who can change your dispatch every five minutes, you're in a much better position than if you can only change it every hour. Right? That should be pretty intuitive. And I highly recommend the NERC report, from the Integrating Variable Generation Task Force, a very reasonable, balanced report on all of these issues. And you can see the statements that were made there, and then some of the studies down near the bottom. Bonneville and Avista found, in one case, an 80% cost reduction for wind integration just by going to these shorter dispatch intervals, and Avista, found a 40-60% reduction.

Again, if you're the grid operator, you're looking for flexibility when you get new variable resources on your system. And you should start with the lowest cost. So some of these market operations functions are the least cost things to do.

There is talk about using more gas. And that's an option, too --supply side flexibility, or flexible generation. And it is a positive thing that we're getting more flexible gas generators on the market.

Storage gets a lot of talk. It is on the high right side of the curve right now. It'd be great if we can bring that down over time through R&D. But at this point, it's not the least-cost way to add flexibility to the system.

Larger balancing areas would help a lot. You could do this virtually or physically. You could just do it through coordination between neighboring balancing areas. But if you think about electronic counting, basically, where you might have one balancing area taking expensive actions to ramp generators down and the neighboring one taking expensive actions to ramp generators up--well, to the system, from the point of view of the area's reliability, both of those are wastes of money. And they cancel out, if you just coordinate or net out the imbalances.

We still have over 120 balancing areas in the country. So we have a very inefficient structure in many areas. And this is harmful for reliability and efficiency as well as renewable energy integration. Again, you don't necessarily need to change the institutional structure or the ownership or control or jurisdiction. There are technical, physical ways to address this through cooperation. I'm going to let you look at some of these in the interest of time.

Forecasting is critical. Markets are critical. There were a few relevant points yesterday--I think Speaker 2 in Session Two emphasized more efficient ancillary services markets. I totally agree with that. The moderator of Session Two mentioned that ancillary services markets would help a great deal. And I would say, the sort of off the cuff thinking of, "Well, we should define it according to the characteristics of supply"-- I would flip that over. And with my own armchair economist off the cuff thinking, I would say that products are usually defined according to the needs of the customer. Let's define what the customer--the system operator--needs. If they need somebody to respond in ten minutes, if they need somebody to respond instantaneously, or whatever, let's define that product. And then let anybody compete--wind, gas--let anybody compete to provide that product. That's a much more competitive way to do it.

And also it gets away from, you know, we have legacy ancillary services and things like generator imbalance charges, which make no sense from that perspective. That's defining a product based on characteristics of supply rather than what the system operator actually needs. And it prevents certain sources from supplying the service.

So just a couple points and I'll close. What are the implications of all this for gas generators and pipelines? There will be likely more demand and need for flexibility and dispatchability. In terms of pipeline infrastructure, I think the big issue there is really how much coal to gas switching there is going to be. That's the big driver. If you're doing, say, 100 megawatts of new wind, then instead of the INGAA ICF number of 30 gigawatts for gas, we think it's about a third of that, based on the utility studies. But, you know, look, let's build the pipes we need. Let's increase the flexibility of gas storage, flexible generation, and then all of these market features that will increase flexibility, as well as promote reliability and efficiency. Thank you.

Question: On your first slide of the slides that were handed out, you had a description of how much change can occur in each market over certain time intervals. Was that an average change? Or was that sort of an on the extreme, you know, like, one in a ten-year maximum change?

Speaker 1: I'm going to have my brains answer that [refers to member of audience].

Response: It's one standard deviation.

Question: But would that be similar to what operators want to plan for?

Response: Usually operators plan for two standard deviations, so you'd double those numbers.

Question: Would it just be simple doubling? OK.

Speaker 2:

When I put this presentation together, and there are a lot of slides and there are a lot of appendices, I remembered an Aesop story I told to my children. When you try to please everyone, you please no one. So I hope there's one slide in this packet that everyone finds useful. And I'm sure no one will be happy with all my comments.

But with that said, pipelines are ready to back up and do back up the power grid today. We have quite a bit of flexibility. Just how much flexibility there is depends on the time of year, the location, and the region that you're in. But what I'd like to do is go through some examples, some very specific cases. And you have the data here.

In general, El Paso Corporation is the largest natural gas transporter in the United States. El Paso is both an E&P company and a gas transmission company. I'm going to speak to just the transmission. I'm going to go through a real quick brief background of the natural gas pipeline industry, talk specifically about El Paso's facilities, since we are fairly large, and then show some examples of specific areas where we've handled drastic load swings, and then some of the expansion projects we're looking at where we need your help because we haven't been able to cost justify some of the projects I think that are vital to backing up the network, both the power grid and the pipeline grid.

A few facts. Pipelines were typically designed back in the late '30s, '40s, '50s, and '60s to meet the LDC load. So you designed your pipeline to meet 100% of the winter load, which meant that most of the time, you weren't fully loaded. So there was a lot of flexibility on the pipelines when they were originally laid out. Today, pipelines are pretty much designed for what people are willing to subscribe for. If someone signs up for 500 million cubic feet or 500,000 decatherms, it's pretty much what the pipeline is designed for. We have no spare pipe in the ground typically and no spare compression as a rule. Unlike the electric industry, where you'll have an N plus one design where you might have a backup machine if something trips. We have just what we need. And that usually works because we're designed for that peak day.

We've all used the term "line pack." That's the amount of gas that's in the pipeline. And I'll talk about how much is in the Tennessee system. But there are really two kinds of line pack. There's the amount of gas you have to have in the pipe just to keep it pressurized so gas will flow from the pipe to the customers that need it. And then there's that incremental amount of gas that's in the pipe that stands above that base gas you have to have that you can use for flexibility. And we have some.

We've heard a lot about shale gas and you're going to see some similar shale gas slides in my presentation. It has really turned the world around. A pipeline that once delivered a billion cubic feet a day, if it suddenly finds itself with a shale gas field sitting on top of it, that same pipeline could now move two billion cubic feet a day. So I want everybody to not get trapped in the idea that a pipe was designed for a fixed set of volume at a fixed cost, because new supplies, as technology improves, can double or triple pipeline capacity in ways nobody really had thought possible before.

I also want everybody to take a step back. We've heard a lot of stories in the news about pipeline reliability. And I threw a statistic up that'll get me in trouble, but here it is. We deliver 99.99% of the firm scheduled gas. Pipelines are highly reliable.

This map is the gas transmission network across the United States, over 300,000 miles, both intrastate and interstate--highly reliable. This is a grossly simplified diagram. When you hear about horrible cases of a pipe breaking, typically there are multiple lines in parallel. So losing a single line doesn't take the pipeline out. It means a section that we isolate and then route around is taken out. It's a lot like closing a lane on a major highway. So that's why I say the system really is very reliable.

Here is the shale gas map you saw before. I want to focus on the eastern part of the United States where you see these huge fields. We've heard a lot about the Marcellus field. I've seen estimates of 100 trillion cubic feet recoverable. That's significant to me because we have a lot of pipelines in that area. It's changed our flow patterns.

I would offer everyone the idea that pipelines could be batteries of the future. There are compressor stations located throughout the United States, typically at 60- to 80-mile intervals. There are opportunities for us to run those compressor stations and pack gas into the pipe in off-peak times to build up that line pack. You need a way to pay for it. You need machines designed to do it. But it's possible. And as you see from the map, there are a lot of locations out there where it can be done.

Within El Paso family of pipes, serving that system, if you look in the northeast, just through dumb luck, the Tennessee system happens to bifurcate the Marcellus field, and it has literally doubled the capacity of that pipeline in ways we had not anticipated even two years ago. We're delivering about 13% of the total gas in the United States through the Tennessee system, and on any given day, about 26% of the gas that's actually flowing to consumers.

This map is a snapshot of the Tennessee system. And I'm going to blow this up because I just want to give you a few concrete examples. It's 13,800 miles of pipe. And if you think about it, it's only about 2,500 miles from Texas to New York. The reason it's so long is, again, the multiple parallel lines. That's what allows us to be highly reliable. There are a lot of points to come on and off the pipeline. In general, this pipeline is designed to do about eight billion cubic feet on a peak day. But because of the new storage fields and gas coming on and off, just like a major highway, the capacity could be doubled. There's 90 billion cubic feet of gas stored. There's 50 billion cubic feet stored in the Pennsylvania New York area, 30 billion down in Louisiana. We can take substantial outages and still get gas to the market. And there are 72 compressor stations that will adjust and shift gas through the pipelines to meet peak needs when we're not fully loaded.

Another important factor to recognize about pipelines, though, is this--when we are running at 100% load factor, that means we were designed for people to take their gas on an even hour basis. People usually nominate a volume of gas over 24 hours. So they might nominate 24,000 decatherms. I would, as the designer, expect them to take a thousand decatherms an hour. That's how the pipeline was designed on that peak day. Under those peak day conditions, there is no line pack available. So this is where I gave that first answer. It depends on our ability to meet market needs. When the pipeline is not fully loaded, we have a great deal of flexibility. When it is fully loaded, we have almost no flexibility. So it's important for people to hold capacity.

Here is a quick look at how the power plan demand has changed. This could be due to the recovering economy. We think some of it is coal switching. But in general, we've seen very high load factors on the system. What I found interesting when I looked at the power plants and how much they have contracted is that there's about 5 billion cubic feet a day of potential burn capacity connected power plant load. It's about 23,000 megawatts connected to the Tennessee system. Of that, only about 1.4 billion cubic feet is contracted for. So roughly a quarter of the potential load holds firm contracts. So the other 75% is naked. And that's important on those peak days. You've got a lot of potential connected load that has no ability to get the gas there.

There are 24 major power plants that we track on a five-minute interval. So we're very aware of what's happening on the pipe, who's taking the gas, and when have they scheduled it. How are they working? Of those 24, the bulk of the capacity is held by just four plants. So one of the other themes I'd like to harp on is that a very few are carrying a bulk of the burden. And I'm hoping we can change that.

This is a snapshot of the northeast. Almost all the major plants in the northeast tied to the Tennessee system are fed off what we call the 200 line. And I have two red circles on here, station 245 and 321. These are key restriction points on our pipeline. What I saw this winter was that these power plants you see called out in the yellow text boxes ran fairly heavy. They burned on some days almost 2 billion cubic feet a day, a very high rate and very unusual from what I've seen. Station 245 (the yellow squares, are compressor stations) was restricted 96% of the time this winter, meaning there was more gas being attempted to be scheduled and flow through that station than what we were physically capable of doing. There is tremendous demand out there. There is a need for additional resources. And obviously we made it through the winter. It works. But I am just giving everybody a heads-up. On a regional basis, there are some areas of the pipeline network that are incredibly heavily loaded.

Station 321 sits in the heart of the Marcellus. It has typically seen very low restriction percentages. It was probably restricted 50% of the time this winter because demand was so great that it exceeded capacity--very heavy demand.

Flow has reversed on this system. We used to say on the 300 Line, the capacity was 700 million cubic feet a day. Today, it's 1.4 billion cubic feet because we're flowing gas in both directions. Gas is coming in from the Marcellus, and we've reversed that pipeline. So that gives us the ability to support a lot more load. But there's not a single power plant of any size connected to the 300 line. We've tended to cluster facilities. And I think we need, at a macro level, between the pipeline industry and the power industry, to lay our grids on top of each other and take a look and ask ourselves, are we really taking advantage of resources that are out there?

Again, this diagram is overly simplified. The 200 Line is actually two pipelines, capable of moving over a billion cubic feet a day, whereas the 300 Line right now is a single line.

Here are some examples of what's happening and some of the flexibility that's in the pipes. Along the X axis of these charts, those are days. 9:00 AM is the start of the gas day. I hope everybody knows why we start the gas day at 9:00 AM. This really gets back to the producers, and to the fact that you physically have to open wells. And in some pipeline networks, you'll have 30,000 wells behind the gathering systems that feed the transmission systems. So the gas utilities and the producers have always wanted the gas day to be in the morning, so that when there is a change, you can send people out in daylight hours to make those physical changes to the gas flows. And one of the big disconnects we have to address is the gas/electric disconnect.

What you're seeing in this pattern and along the Y axis is the flow of gas, both scheduled and what's physically flowing in hundreds of thousands of decatherms. So if you look at the yellow line [showing physical hourly flow], it's peaked up almost as high as 800,000 decatherms. The blue line shows what is scheduled.

There is an incredible amount of volatility--half a billion cubic feet or 500,000 decatherms intraday--that the pipeline is supporting with line pack to meet these needs. What's happened is that at 9:00 in the morning, we're being grossly over-pulled above design capacity.

On this slide, I'm showing you that same 200 Line capacity of about a billion cubic feet a day. That's the red line. And the yellow line shows the demand--gas leaving the pipe--that's substantially greater. In fact, on December the 9th (this is fairly recent data) there was 1.5 billion cubic feet leaving the pipe and physically flowing through the pipe was just one. What was happening was that line pack was being drawn down. Pressures were falling. I was also losing hair at this point trying to figure out how long we could keep the grid up, talking to the power plants, letting them know, "Dudes, you're over-pulling the system. And it's not going to be me shutting you in. You're going to pull this pressure so low you're going to take yourselves out."

Fortunately, LDCs typically only need one to three hundred pounds pressure on the main line. Most of the power plants need about five hundred pounds of pressure. But we've had some real hot moments and some real frank conversations with each other that need to happen, and they need to happen more efficiently. There is a huge disconnect that the control centers aren't allowed to communicate clearly with each other. There are rules out there that prevent power plants from telling the pipelines when a major plant goes down. Usually I figure it out because I suddenly see 600,000 cubic feet leaving the pipe over a period of 15 minutes, and I realize, shoot, somebody just lost a nuclear plant or a major coal plant. And then I'm on the phone with the ISOs and a couple of the gas plants. And I see them suddenly coming online, and they have not scheduled gas for the day because they didn't know they were going to get dispatched. And I'm giving them a heads-up, "Guys, I think we can take this for two or three hours. But if you keep it up, we're going to have a problem."

So pipelines are highly flexible when the gas is there and we know what's going to happen. But we need to have better communication to meet that.

This chart is a snapshot from a couple summers ago. Each one of these lines represents a power plant. On the left-hand column, that's the flow in decatherms. So that first line shows a plant that is flowing 70,000 decatherms. They've accumulated 20,000. They scheduled close to 70,000. And the pressure is 705 pounds. So this is an example of a great power plant operator doing the right thing. As we kind of walk down that line, you see the second line. This power plant is flowing 30,000. They scheduled 11,000. Things are starting to look uglier as you move down. We try to keep the pressure above 500 pounds. We've already fallen below 500 pounds at a couple locations. The reason we've fallen so low is the over-pull--if you look towards the second line from the bottom, you see an example of a flow of 707,000 on a schedule of about 600,000. So that's an over-pull of only 100,000 decatherms a day. It doesn't look that bad. But look at the last line. This is the total gas leaving the Tennessee pipeline. 2.4 billion cubic feet is flowing out at an instantaneous rate from the pipeline. And we're receiving 1.6 billion from the producers. It's this disconnect that comes from all of this load suddenly coming on and taking gas off the pipe faster than it's coming in that is causing problems. And we can meet that, and we did get through this day. But it was another one of those cause my hair to become a little thinner.

What can we do to make the system more robust and support the systems? I think we need mechanisms for power plants to flow through transportation charges. I'm seeing just a very few power plants holding firm capacity. And what they're telling me is, "Look, if I'm the last guy dispatched, if I'm an intermittent load, I can't afford to hold any capacity on you, Mr. Pipeline. And when I do get dispatched, it's usually late into the gas day. The gas has already been scheduled and people have grabbed up the pipeline space. So I can't get my gas. So I'm just going to take it off you."

We need to find a way to stop that. I think we treat the power markets now somewhat like a poker game, that somebody's bluffing and they're waiting to see if they're going to get called. Maybe you've got to ante up. Maybe everyone bidding in the market should hold some nominal percentage of what they can burn as a requirement to level the playing field, so everybody is sharing in some portion of the cost. That will enable us to build new pipelines and make the systems we have more robust.

What if the ISOs or the RTOs held capacity on those days when the prices blow out, and there's not capacity available to be had or maybe a marketer has caught that capacity, and they're not going to release it until the price hits some magic level? If the RTO held some of that, they could spread that cost among all of the users and then clip those nasty spikes in prices that we see occasionally. These are just some ideas I have.

For the pipelines, we're challenging each other to think about how we maintain our own line pack, how we're selling our services on our pipe. We need to have hourly services to support the power plants. They're going to cost more. And people are right now not willing to pay those costs. A few pipelines, though, have been successful in doing that. But right now, we want to make sure we're encouraging new infrastructure.

We really need to have better communication between the RTOs, ISOs, and the plants themselves and the pipeline control centers. I'm not interested in talking to marketers. I'm interested in protecting the backbone of our nation's infrastructure. The communications right now are terrible, just not as good as they need to be.

Part of that problem is the disconnect between the gas and electric days. In your appendix, I have the gas supply schedule. There are four cycles during the day where people can schedule. But a lot of pipelines, including Tennessee, allow people to schedule on the hour. Changing scheduling is not the problem. It's getting the gas to flow and having pipe capacity to move it. This is a 48-hour snapshot of line pack and how it swings, how we cycle from 12 billion cubic feet down to 11 billion cubic feet. You can see the huge swings intraday. We know what the patterns look like. We manage it every day. What we've seen is that wind tends to drop off in the afternoons and the gas fired plants really ramp up. Knowing that helps a lot.

Here is another snapshot from ERCOT. If you've seen just how volatile the wind is, you need to have some backup. I love wind. The Tennessee system is 10% electric motor driven compression. By using electricity to drive our compressors, we have more gas to sell. Hey, I love electricity.

In the wintertime snapshot, when I talked about that day where I showed that spike where it went to 1.5 billion cubic feet on a pipe designed to only move one, the pressures fell to 350 pounds and freaked out the LDCs, it fell so low--not fun.

We've got some cool expansion projects. If anybody wants to talk about it, I'll be around. They are somewhat economical. And then there are some projects that people aren't talking about that need to be talked about. How do you get Marcellus gas to where the power plants are? You've got supply. You've got market and nobody with a major pipe there.

Here are just a couple more statistics showing, in the center of our system, how our load has been cut in half. We've got tremendous open capacity. We could take another 2,000 megawatts without blinking an eye in the middle of the system, and then some

Speaker 3:

Good morning. I don't have any slides this morning. And one of the advantages of that is, unlike Speaker 2, who had to put that slide up there with all that little legalese from his lawyers and have his PR folks review it, I didn't have to have them review my comments, so I get a little more flexibility, hopefully.

What I'm going to try to do is give you the perspective of a company that is in the generation business. NRG is, as I'm sure some of you know, both in the generation and the supply business, and a retailer as well. On the generation side, we're one of the largest independent generators. We have generating assets, both across the country from California, ERCOT, Louisiana, and into the northeast. And we also have generating assets across the fuel and the technology spectrum. So we have everything from nuclear to coal, to oil and gas, to wind, and most recently added in solar into our mix.

So what I thought I would try to do is give you some thoughts from the perspective of the business that we're in--on the generation side, both owning and operating existing generation as well as looking to try to develop new sources of generation in the markets that we're in. And I will talk about how that fits into the overall question of how we approach what's happening with renewables as they further penetrate markets, particularly focusing on the gas assets that we both have and that we would look to develop that may support the further penetration of renewables.

So when I think about intermittent renewable resources, wind in particular, it seems that there are really four main issues in trying to bring more wind or intermittent renewables onto the grid and integrate them. The challenges are, first, that there are times during the day or hours during the day when wind has no output, when wind isn't blowing. There's little or no output. That's one challenge, one type of variability.

Second, there are rapid changes in the output of wind projects during smaller times, hour by hour and even minute by minute, as we saw in Speaker 1's presentation. Those have to be dealt with as well.

In addition, and I think Speaker 1 touched on this in his presentation as well, you've got sort of the negative or the anti-correlation of wind to peak load in most markets.

And finally, you've got the question of location. Is wind near where the load is? And if not, how do you get it there?

Really the first three issues are the issues that I would focus on in terms of looking at integrating wind into the grid, and what the role of gas is in that, because of the variability issues. The locational and transmission issue is part of that, but probably less significant for looking at the question of what role gas infrastructure and gas generation is going to play and whether it's up to the task.

So sort of walking through those issues, if you take the first point, which is that there are times during the day--there are hours, blocks of time, longer times--when very little wind is being produced out of particular wind resources. Then you have to have some sort of backup for that, which means you need to have close to 100% reliability backup in some form, whether that's generation or demand response or some of the other products. But you need to be able to back that up, because you know it's not always going to be running. There are going to be times and many hours when in fact wind won't be having any output; it will be near zero.

And up to this point in time, this system (at least in the markets that we operate in, in Texas in particular where there's more wind, but other places as well) we're relying primarily on the existing resources that are there. There has been some addition of specific resources, but not many. We're letting the system essentially provide reliability, provide ramping capabilities--ramping down, ramping up--provide load following, that in essence it may not have been designed for. And it seems to be doing it, but one of the questions will be, how long and at what cost? But in general, right now, we're relying on existing fossil generators and to some extent products like demand response and things that are complimentary.

Storage is a potential source of reliability. We haven't seen a lot of additional new types of storage that are playing much of a role in providing this type of backup for wind and other intermittents. And so the forward-looking question is, what do we need to do, if anything, to try to make sure that we have those resources available? And can the existing resources continue to provide the balance for intermittency? I'll talk a little bit later about some of the specific challenges in some of the markets that we're in.

In addition, you've got the more frequent variability--hour by hour, minute by minute to some extent. And that can be addressed when you have larger wind resources that are better controlled. You can also, I think, address that through forecasting as well, to some extent. But the sort of shorter, minute-by-minute variability requires resources that can provide regulation and some of the faster response products, again, that Speaker 1 showed that are more costly to provide. And those have to be part of what you look at as a solution or as a backup and a reliability consideration.

And then the issue the sort of negative correlation that everyone talks about, the anticorrelation to load that wind typically has is something that also we spend a lot of time thinking about, because that means you're going to have to have resources that can run for longer periods of time when you know load is going to be coming on, typically during the daytime morning hours, before the wind picks back up, often in the late afternoon and in the evening. And that can happen at fairly rapid pace. Again, it's somewhat predictable, but not always. And so you need to have resources that will be available to do that. All that puts tremendous stress on the system, both the system operations and the generation units.

I was listening as Speaker 1, was talking about the view from the wind side of how the system is working. And I think it's clear that reliability can be addressed and we can integrate a lot of wind in. And we are doing that. And there's probably more wind that can come on. So technically, a lot of that can be done.

I think the real question that needs to be asked is, on the physical side, what stress does that put on the existing resources? We have a lot of older plants. We see both coal and oil and gas. And we see them being asked to perform in ways that they're really not necessarily designed for, in terms of cycling up and down, ramping up and down, and coming off and coming on. Some of that is attributable to renewable resources, but not all of it. Some of that is also attributable to just the pricing and the availability of gas and what's happening in terms of spark spread compression and coal to gas switching. So I wouldn't say all of that is attributable to wind, but, especially if you look at Texas where we have a fair number of assets, there is a concern that, as you ask these generating resources to perform this additional function to back up wind, that they're not necessarily designed to do that. So we look forward to say, you need to be having resources added to the system that are better designed to do that, that have faster start capabilities, that are designed to start quickly, come up to load, to max load quickly, and to ramp back down.

But the second question that raises is the cost. Who is going to pay for that? How does that get built and added to the system? And where are those costs put? I think that's one of the biggest issues we see in front of us as we look around the regions that we're in.

For instance, in Texas, to talk about the ERCOT market just a little bit, there is fairly significant wind penetration, as everyone knows. We see wind causing a significant actual need for ancillary-type services that right now are being provided by the system without a defined market and without defined products. We've seen as much as 2,500 megawatt drops in wind from hour to hour and over 4,000 megawatt drops from morning to afternoon. And that has a significant impact, certainly on the gas fleet. Combined cycles plants are being pushed, but not actually running because there's so much wind on. And yet they have to be available to come up at any time. This is depressing energy prices as well as making the economics of gas plants that exist not nearly as predictable or as robust as they were prior to the penetration of wind.

New England has looked at this a little bit. They don't have as much wind, obviously, as Texas, but they have done studies on it. They're concerned. I think New England only has about 270 megawatt of wind right now. But they've got close to 3,000 in the queue. And when you look at the study that the New England ISO did last fall, it's instructive because it comes to the conclusion that I think we've reached, which has raised the question of, where do we go and how do we solve this? The conclusion is sort of intuitive perhaps, but somewhat contradictory. They found that large amounts of wind in New England in the ISO could actually lower energy costs over time. And they thought that that was something that could happen. They thought that the system could absorb fairly large amounts of additional wind. But because of wind's variability, they thought that you'd need additional flexible backup resources of the type I've talked about. Because of the impact on energy price, they also would expect, as I said, that the challenge they faced was, how do you get those additional flexible resources to be built or even pay people to operate them? They don't have an answer for that, but that just highlights, again, sort of the same question.

You know, it's interesting. We obviously operate in the kind of markets--capacity markets in PGM, New England, New York, or in Texas, the energy market they have there--which raise one set of questions about what products might be developed to actually pay people to develop these resources. In some other places, in the more regulated places, there may be utilities that would be willing to try to get that on a rate base. I know I read recently about a utility in Montana, I guess it was Northwestern Energy. And they actually built a 150 megawatt peaking unit just solely for the purpose of providing backup regulation and load following for wind, because they have so much wind there in the area and on their system. We did some rough math. And it looked like they spent approximately $200 million dollars to build that. So that's about $13.45 a kw. They have a pretty small customer base. Let's say they have around 390,000 customers. And just looking at what that would cost, that's about $514 dollars per customer to build this gas-fired backup facility. If you average that over 20 years or amortize it over 20 years, it's about $4 a month for a customer. And the question is, is that the right answer? Is that a cost that people should bear?

I'm not saying that extreme cost would be the case, obviously, in all places. And in the larger ISO and RTOs, you have a bigger pool to socialize that over. But I do think it's sort of instructive as to what we need to all address, which is, how are we going to structure the markets? What are we going to do in terms of putting revenue signals out there that will incentivize people to build this? And who's going to pay for it?

And I think the problem is compounded by the fact that, even without additional penetration of renewable resources like wind, we're seeing that many folks, including ourselves who are in the development business, are reluctant to build new generation, and particularly gas-fired generation, without additional price and revenue support that is not necessarily in the markets already. Obviously FERC has been addressing this with what's going on in PJM and up in New England. And so I think the question of renewables and needing gas generation backup or other backup for renewables will only compound that issue and make it harder. We have to figure out a way to pay people or know that people can get paid if they're building these new resources that will be needed to provide that backup. Thank you.

Speaker 4:

Thanks for the opportunity to be here with the Harvard Electric Policy Group. Before getting going, just let me make a clarification in terms of INGAA and the INGAA Foundation since I'll refer to both. INGAA is the trade association that represents the interstate natural gas pipeline industry. They are the advocates for the interstate pipeline business. The INGAA Foundation is an affiliated group that in some ways is INGAA's research arm. And in addition to including pipeline owners and operators such as El Paso and Speaker 2 and his colleagues, the Foundation has a membership of about 140 companies that range from pipeline construction companies, pipe mills, compressor manufacturers, pretty much the full gamut of those who have got some economic nexus with the interstate natural gas pipeline industry. And a big part of what the Foundation does is produce studies that range from macro issues like how many miles of pipeline are going to be needed over the next 20 or 30 years, to things like best practices for pipeline construction and operation and maintenance.

Let me talk about the purpose of the INGAA Foundation study that has already been referenced. As you know, the topic of renewables integration has gotten a lot of discussion among policymakers and electric industry stakeholders. And yet we think there has been relatively little discussion about what this integration means for the operation of other systems such as pipelines that supply fuel to electric generators. And given the prospect that natural gas is going to play a much greater role in terms of fueling the electric generation fleet, and also that some kinds of gas-fired generators have the rapid ramping capabilities that make them well suited to play a role in renewables integration, we thought that it made sense to do a study to look at, what this means for natural gas, and in particular the services and the infrastructure provided by the interstate natural gas pipeline industry.

This is the report that was released in March of this year. We retained ICF International to do the work for the INGAA Foundation. At a high level, the study concluded that there will not be a significant amount of natural gas consumption in connection with supporting intermittent renewable generators, and in fact, that overall, natural gas consumption may decrease. Rather, what we identified as the critical issues were whether there will be sufficient pipeline capacity, and whether customers have contracted appropriately for the pipeline services needed to support reliable service to rapid ramping generators.

Let me briefly recap the results of the study. First, ICF forecast the growth of renewable power generation over the next 15 years. The forecast is for 105 gigawatts of new renewable power generation over that period, of which 88 gigawatts would be intermittent wind power. The study makes the distinction between the expected variability of wind power, which is accounted for when wind is bid into the system, and forecast error, which can't readily be accounted for when bids are made. And the study assumes that it's this forecast error that brings up the issue of whether you need to back up or firm the intermittent renewables.

The study also acknowledges that this backup or firming can be provided by multiple resources, that they could include things like pump storage hydro, compressed air storage, or other things. Still, for purposes of establishing an outer bound for natural gas implications, the study assumes that all of it will be backed up using gas-fired generation. The study assumes that as much as 33 gigawatts of gas-fired generation may be needed to respond to the forecast error in connection with the 88 gigawatts of intermittent renewable capacity, and that some of this gas-fired capacity may be plants that are already on the ground, and some of it may be new, and that the total gas usage associated with this firming generation will be about 440 BCF in 2025, which, as I said earlier, really is not a significant amount of gas consumption. It's only about 2% of current U.S. gas consumption.

As Speaker 1 made clear in his comments, not everyone has warmly greeted the results of the INGAA Foundation study and ICF's work. While we could discuss and debate that, I really don't think it would be productive here, because I think in some ways the points that we were trying to make in the study can be made without needing to debate those numbers. Because regardless of whether you agree with ICF's projections, it's fair to say that integrating and increasing the level of renewables is going to have implications for how the electric grid is operated, for how other kinds of generators are dispatched, and for the sources of energy used to fuel those generators. And as already noted, the study makes the point that there are multiple options for performing this, but the study still points out that, at least based on what we know today, gas-fired generation is the most cost-effective alternative for doing so.

Even if the market chooses to rely upon a portfolio of services, it's safe to say that gas-fired generation is going to play a significant role here. Therefore, I think that we need to be looking at the commercial, operational, and regulatory implications for natural gas pipelines serving these rapid ramping generators.

The study also points out that the impact on gas pipeline capacity and pipeline services is likely to be very pipeline- and location-specific. And so even if the total magnitude of gas demand created and the total amount of generation needed are different from what's in the study, nonetheless, there will be issues that will need to be addressed on a location-specific basis, where rapid ramp-rate generators create special demands upon pipelines and pipeline services.

And then finally, I think it's important to note that many of the gas supply and pipeline issues that arise in connection with the role of gas in integrating renewables also arise more broadly in connection with the role that gas will play in terms of fueling an increasing amount of the electric generation fleet. So I think that this discussion serves to highlight some of those issues that are going to need to be addressed as we look at an increasing role of gas fueling electric generation.

In thinking about how to approach this issue, I thought that kind of a build-up, looking first a gas pipeline fundamentals, second at pipeline services to electric generators, and then third looking at unique issues associated with serving firming generators or rapid ramp rate generators, would be a good way to go. Fortunately, Speaker 2 has already covered a lot of this in good details and has provided some good anecdotes from an operator's perspective. So I'll be able to get through this, hopefully relatively quickly.

As Speaker 2 noted, a gas pipeline is designed to support customers' primary firm gas delivery obligations. Unlike the electric side, there is no reserve margin designed into a pipeline, and no extra capacity exists above that coincidental peak firm day capacity, in other words, the day on which all of the firm shippers decide to take all of their firm contractual entitlement.

As Speaker 2 noted, most pipes are designed to provide uniform service over a 24-hour period--you hear the term "ratable takes," and that places some limits on the hourly flexibility of what a pipeline can deliver. However, as noted, much of the time the system has got considerable flexibility because not all firm customers are exercising their entitlements. And this creates the flexibility to serve interruptable customers, the flexibility to serve secondary market customers who may nominate at points that are not their primary receipt and delivery points, and also the ability to accommodate the demands for service on a non-ratable take basis.

A point I think that's worth making here--and I think it will play in as we talk later about the demands that are created by a gas-fired generator, and particularly a rapid ramp-rate generator--is that I think there's a contrast between the commercial performance or commercial construct for pipelines and the operational reality. And here you've got to understand that gas typically moves through a transmission pipeline at about 20 miles per hour. It is not the instantaneous transmission of electricity. It's a relative snail's pace. And so how can gas be scheduled for receipt by a pipeline for example at 11 AM today in Louisiana to be delivered at a customer's facility in New Jersey at 9 AM tomorrow morning? It's very clear that it's not the same physical molecules that go into the pipeline in Louisiana today that are going to show up tomorrow in New Jersey. And that gets into what Speaker 2 was talking about, about the pipeline's ability to manage the flow using line pack to be able to meet the commercial obligations to deliver the customer owned gas that's in the pipeline and also provide the flexibility that is needed.

In terms of serving electric generators, I think in restructured power markets (and Speaker 2 touched upon this) there is very little incentive for generators to hold firm pipeline capacity. Think about it. It places them at a competitive disadvantage relative to generators that do not have that cost obligation, and also, most of the time, there's the flexibility to serve them relying upon the fact that not all firm customers are using their capacity, and the fact that probably much of that time they can pick up the capacity on a discounted basis. So for them, it's a rational economic decision to choose not to take firm pipeline capacity.

But what happens on that day when all of the firm customers choose to take their contractual entitlements and there's no capacity left over? And what happens as we look ahead to the increasing utilization of gas for electric generation?

So if incentives stay the same, you are going to have an increasing number of customers placing demands upon a limited amount of flexibility in the system. That will likely come to be exhausted sooner and sooner. And so you kind of have a question here that comes from generators making very rational economic decisions. I don't criticize those decisions. But what does the aggregate result of that mean, and might there be some implications for reliability?

And then, as Speaker 2 noted, there are a series of operational issues that come up. What happens to system pressure and line pack when generators ramp up quickly and on short notice? And of course this becomes even more complicated when you have generators who take gas off the system that they haven't nominated and scheduled. And not only what does that mean for service to them, but what does it mean for service to other electric generators and to the other customers on the system, the LDCs, the industrial customers, others who have got pipeline capacity?

I will concede that even for generators that schedule firm service, there are some challenges. There is the coordination of the gas day, which at least is uniform across the United States, with the electric day, and the fact that various ISOs and operators and grid operators don't have a uniform electric day. And often it's the case that generators learn they're going to be dispatched after the time for nominating gas into the system has passed. What do you do then? And furthermore, there is a FERC open access rule called the "no bump" rule that can frustrate this even more, because if a shipper with a primary firm point does not nominate and schedule, and another shipper steps in and nominates and ultimately the gas is scheduled for that point, and then the primary capacity holder comes back and says, "Guess what, I just found out I'm going to be dispatched,"-- oops. They can't get it there because the secondary party who showed up can't get bumped.

This is also potentially a controversial issue because, quite frankly, interruptable customers like the ability to step in and nominate the capacity and not get bumped once they get scheduled.

There is a lot of discussion about moving toward a uniform energy day. It has been discussed before. I think there will be greater emphasis on it now that we've got such a focus on electric and gas interdependency. But the point I'll make is that addressing that issue does not get to the fundamental issue of pipeline capacity. Is there an incentive for shippers to sign up for that capacity? And what are the consequences if you get to a day when all the firm shippers are utilizing their capacity and there is none left over for others? No amount of synchronizing the energy day, no amount of communication with grid operators is going to solve that fundamental problem.

Now let's talk about pipeline service to firming generators or rapid ramp-rate generators. And I think there are two issues here, economic and operational.

First, there are cost recovery issues. These are services (and this is borne out well in the study) that are not going to be used at a high capacity factor. Utilization of them is going to be sporadic and infrequent. And yet, for the purpose of ensuring the ability to serve these customers, you need them to take firm service. Otherwise, if there need to be infrastructure enhancements made to support that service, you're spreading that across very few units of service, and what challenges does that create?

Second of all, deliverability issues. With these rapid ramp-rate generators, major changes in requirements can occur within only minutes-- and major changes going both ways, not only ramping up but ramping down. How do you deal with that in terms of the impacts on the pipeline?

This slide illustrates the point about the unit costs associated with serving these facilities, and illustrates mathematically that if you have got a facility that is being utilized at a very low capacity factor, then the unit costs become quite expensive and you run into some issues in terms of whether you have the right revenue signals that will enable people to make the investments they need for the gas delivery to be reliable.

In the study, ICF did some transient flow modeling. They constructed a hypothetical pipeline that had a number of customers, some LDC customers, some merchant generators, and then also some rapid ramp-rate firming generators, and then ran through a series of scenarios. The point that became apparent was that there were some times, particularly if you assumed a relatively low delivery capacity in the lateral that was serving that customer, where the pressure might drop to a level that would cause the power plant to trip or conceivably would create issues for other customers who were downstream. And so it illustrated that while for most of the time, on most pipelines, there's considerable flexibility in the pipeline infrastructure, there may be times when there simply is not the infrastructure to support the delivery at the pressures that are needed for the rapid ramp-rate generator.

This gets back to the point I made earlier about contrasting the flow rate for gas through a pipeline versus how quickly electricity flows or how quickly these rapid ramp generators may be needed. You need to have the ability to have that gas, to have that line pack, to have that compression relatively close to that generator to be able to respond very, very quickly. And that was the point that was made by the transient flow modeling that was done in the study.

This then gets to a series of interrelated natural gas ratemaking and electric power ratemaking and market design questions.

Number one, to what degree are these pipeline services going to be deemed to be unique services to serve this particular class of customers? Or are they going to be deemed to be services that are part of maintaining the reliability of service to a broader class of customers, taking service under some generally applicable tariff provision?

That then gets to the question of, do you create special services for these customers? And can you get that? Even if you can--as illustrated by Speaker 2's comments—the next question is, what is needed to create the incentive, or for that matter, the compulsion, for generators to sign up for the services that they need if in fact there is a reliance on those generators for reliability? And there may be times when either an interruptable service or the generally applicable firm service will not be sufficient to guarantee that they will be able to receive gas deliverability as they wish and need.

And I think that's something that's got to be sorted out on the electric power side of the equation. This gets thrown in the basket of issues that Speaker 3 talked about. What do you need to do to provide the revenue certainty or the revenue incentives for people to make the investments that are needed to integrate the renewables and to ensure that you have got what you need to respond to variability? And, as highlighted by Speaker 2, the broader issues associated with the greater use of gas generation in the market and the demands that that creates, particularly as we forecast the increased utilization that is likely to occur.

In concluding, let me get to a point that I think was kind of begged by the title of this panel. And it was something to the effect of, "Is natural gas infrastructure up to the challenge?" Assuming that generators contract properly for pipeline capacity, there are no operational impediments to gas pipelines serving gas-fired generators, including the rapid ramp rate generators, reliably. It's an economic question. It's a contracting question. And it's a question of whether there are the appropriate incentives and revenue signals to get them to contract for that capacity.

My second point in conclusion is that integrating renewables is going to necessitate changes in how the grid is operated. That's going to create costs and necessitate decisions about cost responsibility. And we didn't, in this paper, wade into that debate, but we know that it is a debate that is raging among stakeholders in the electric power industry, and is one that ultimately the regulators and policymakers are going to have to address in some form.

Clearly, gas-fired generation is an option for dealing with the demands that are created by integrating renewables. And our point is that, number one, it should have an equal opportunity to compete with other alternatives, and that if chosen, there should be the ability to recover the costs that need to be incurred to ensure the reliable delivery of natural gas, which ties in with the reliable delivery of electricity.

Question: Both yours presentation, Speaker 4, and Speaker 2's presentation put a lot of focus on the winter peak, stress on the system, etc. But clearly, at least for PJM, the summer peak is what it's about. And frankly, as I understand it, that's where the intermittent issues of wind become greater than they are in the winter season. So I'm worried that not lining up the situation in the summertime in terms of electric peak and the situation on the gas. And if I had all those numbers for the summer season, tell me what they would show with regard to the amount of headroom on the pipeline system.

Speaker 2: In your appendix, the slide where I showed the 2.4 billion cubic feet leaving the pipe and the 1.6 coming in, that is a summertime load. We were designed for the peak winter day, so what happens typically on pipelines in the summertime is that the LDC loads virtually go to zero. So our ability to serve the power plant loads is tremendously improved, so long as gas is scheduled. Usually, if no gas is scheduled, those 72 compressor stations are shut down. They are not running. And to bring them back online takes time. Some of the machines were built in the 1940s. So as long as the gas is scheduled, I'm not so worried in the summer.

In the new northeast for ISO New England, I'm a little more concerned because the pipe telescopes. When I showed you that diagram of the Tennessee system, it will have four and five pipelines running through Tennessee and Kentucky, 30 inches in diameter, moving billions of cubic feet. By the time you get into the New England area--and this is why it's a regional issue--you're down to two lines moving one billion cubic feet. So if the need for gas-fired generation increased substantially above where it is now--and I mean physical assets, because I'm seeing all the plants connected now, running basically--then I would be concerned. But right now, we're meeting the needs, and almost every single power plant is online today.

Question: If I could just clarify, what I'm hearing is that it's really a scheduling gas/electric coordination issue in terms of Speaker 1's presentation, more so than a firm transportation issue in summertime. Am I correct on that? The remedy here is addressing some of the scheduling coordination issues.

Speaker 2: It depends. I hate to give that answer. Typically, I tend to agree with you. In the Northeast, in that region, it is a scheduling issue, because your LDC load virtually drops off, which frees capacity up for the power generators. But they need to hold firm space or some level of firm space so that they get dispatch. We've seen a couple of new plants built completely naked. And they'll come on and take the gas, betting that they can buy it intra-day. And some days, they can't.

Speaker 4: To add to Speaker 2's point, the other question here is, while Speaker 2 is correct that you have not got the same issues in the summer as you have got in the winter, nonetheless, looking forward, as we see forecasts of increasing amount of gas-fired capacity, what happens then? So let's be looking forward on this thing.

And then while the LDC load, the space heating need market and things of that nature, obviously drops off in the summertime, there is utilization of the pipeline in the summer for storage refills. Summer also tends to be when the pipes will schedule maintenance and things of that nature. And so while the issue is not as acute as it is in the winter, if we're looking forward, we still ought to be thinking about whether there are the right incentives to hold capacity? And what happens as more and more gas is consumed for electric generation?

General Discussion:

Question: This is somewhat of a clarifying question, but it may shade over into the policy discussion. And it has to do with statements made by Speaker 2 and Speaker 4 indicating that generators need to step up to the plate and take firm service. But I was wondering if you all could discuss a little bit the impact of the "no bump" rule. Some people may not know what "no bump" means, so this is partly a clarification question, but could you also speak to how that might be a negative reinforcement for taking firm transmission, since you may not be able to get your firm transmission during the day when you need it anyway? Could you talk a little bit about that?

Speaker 4: I think it was something I mentioned briefly in my comments and I noted that it may operate as a disincentive to take firm capacity, if you choose to incur that fixed cost, and then you find a situation in which just because of when you find out you're going to be dispatched, somebody has already nominated and been scheduled at that point. And so what could be argued is that it devalues firm capacity. I think that it was a rule that was created by the commission as part of gas restructuring to encourage competitive gas commodity markets, competitive gas pipeline capacity markets. The question is, does it need to be reexamined as the Commission looks at these electric and gas interdependency issues?

By the same token, I would anticipate that a lot of interruptable shippers and those who utilize released pipeline capacity and like to have that flexibility will probably push back against it. And it will be interesting to see where that debate comes out.

A point that Speaker 2 and I both mentioned, but probably didn't stress that much in our remarks, is that when you're looking at the uses of natural gas, and when you're looking at the demographics of the shippers on pipeline systems, it's not just electric generators. You've got local distribution companies. You've got industrial customers and others. And so some of these issues that we highlight are not just going to be the pipe and the generators. It's going to be the pipe and the generators and quite frankly the rest of the customers, and particularly a lot of the LDC customers who are going to say, "You know what? We're the ones who paid for the pipe getting built initially. We're the ones who were paying the freight for the firm capacity. And it's on the back of the flexibility that we've created that the rest of you are utilizing this system." And so it will be an interesting debate in which there will be multiple stakeholders.

Comment: I think the no bump rule had a lot of good intentions. The bump rule had good intentions from the idea that if someone's not using their capacity, and they bought it firm, but someone else would like to use it, they could come on and use it. And once they started using it, they had some level of assurance that it would be there for them for the rest of the day. That was the concept. The problem is that companies that hold firm capacity don't always know what their load is. Weather changes. Things happen. Companies that hold firm, because of the "no bump" rule, will schedule all of their capacity, knowing they don't need all of it. So now the secondary market can't get hold of that capacity. And then we, the pipelines, get on them when we catch them doing that. So then they release that capacity and something goes wrong, and they need it, but they can't get it. And they're the ones that paid the firm rates. The people that picked up the gas are paying pennies. And they're not supporting the infrastructure. So I think it was a really great concept that is really having negative consequences for the industry.

Question: I have a question but I just can't resist a comment on that: get the prices right. I thought we had this conversation 25 years ago. So for releasing gas is you just had tradable rights and people that firm could sell it to other people officially, as opposed to unofficially—it seems like this all has a pretty straightforward solution.

That's not my question. Here's my question. And it came up yesterday. It comes up all the time. And it's just one of those things that keeps nagging at me. It's these levelized cost comparisons. Everybody's using them. And I understand why. It's easy conceptually and so forth. And when you're comparing things that are levelized in their production, it's perfectly fine. You know? That's the right thing to do. But then we get to another chart and they talk about the correlation effect--I think that basically means the wind blows at night. I think that's what that term is supposed to be referring to. And so just to make the example obvious, if power is free at night and expensive during the day, then if wind is blowing at night, its value is zero, even though it's levelized value might be $50 dollars a megawatt hour if it was producing during an average day.

So the levelized cost number is not the relevant comparison for things that are not levelized, dealing with the fact that the revenue profile over the day is dramatically different. And my question is, how much difference does it actually make? And is this a second order thing? I mean, the example I just made up, it's 100% of the story. It's 100% wrong. Right? So levelized cost of $50 dollars a megawatt hour for a power plant that only produced during periods of time when power price was zero, then that plant wouldn't be profitable and you shouldn't do it even though its levelized cost was lower than the levelized cost of other things that produced when you needed it. So how much is that a problem in doing all of these cost comparisons that we're looking at?

Speaker 1: I can respond. Let's keep the supply issues on the supply curve and the demand issues on the demand curve. Right? So yes, utilities do take into account their willingness to pay for services over time when they are considering buying wind versus other resources. But if we're drawing a supply curve, let's look at the cost issues that go into that supply curve. And so the levelized costs are the cost issues that go into the supply curve. But I do think your issue is …

Question: I disagree with that. That's technically not correct. So it's the wrong model. It's a shorthand when you're producing, if you take out what the actual production profile is and you assume it's always the same, it's a useful shorthand. But when the production profiles are different, then you've got apples and oranges. And levelized cost doesn't solve this problem of calculating the supply of apples and oranges, because it doesn't address what this profile is. So when you get these shorthand summary tables--and it could be a big number. It could be a small number. I just don't know what the number is.

Speaker 1: Well, there are different products. I think Speaker 4 of Session Two mentioned in her slide that there are different ways to slice and dice the product. The simple product is energy. But there are other products. There's capacity, ancillary services, and energy at different times of day. Wind does blow harder at night in some places, but not all places. And each region will have a different profile. And you could look at the different products if you wanted to. And, you know, the utilities that wind developers deal with are absolutely doing that. They're looking at what they need and when.

Question: I think the reverse is true for solar, right? The levelized cost undervalues what the solar is really worth?

Speaker 1: Again, it depends on the region. Look at the California studies. Actually the solar drops off about when the wind picks up. Each one captures about half of the peak. So, you know, if the peak is sort of 2:00 to 8:00 PM, the solar is very strong from 2:00 to 5:00 and then drops off. Wind is very strong 5:00 to 8:00. So together, they're getting the peak. Neither one is, on their own. But they are both contributing to providing energy at peak times.

Question: How does the secondary market enable people with firm capacity rights to trade in those firm capacity rights? Why doesn't that relieve some of the issues that were discussed and things? This question is for Speaker 2 and for Speaker 4 primarily. How does the secondary market play out in all this?

Speaker 4: I'll take a first shot at it. I mean, my impression is that it does play a role, particularly now with the Commission having released the price cap on short-term capacity releases. If you hold firm capacity, you have the ability to collect that premium. By the same token, given that on a lot of pipelines and particularly pipelines in a market area, the bulk of the capacity is held by natural gas, local distribution companies have got a public service obligation to meet their retail load. And so consequently for them, they're not going to release the capacity for the higher price and then say to a residential or commercial customer, "You're not going to get your gas today." Now there are some times, and Speaker Two can build on this one, it may be that on that coldest day, when they're utilizing their peak-shaving capacity behind the city gate, in fact some capacity may get freed up and they would do that. But again, the recognition is that we've got a model where, particularly in downstream markets, the bulk of the capacity is held by LDCs. They've got a public service obligation. So they're not necessarily going to be operating from a pure revenue-maximizing model in terms of putting that into the market so the electric generator or whoever can get it and values it higher.

Comment: That's exactly right. There's a very robust secondary market. We can get statistics and so on to say that we see a lot of utilization every day. But on that peak winter day, the LDCs, who are the primary users, and certainly the power plants have not contracted for their full needs. They rely on propane, LNG, and other peak-shaving sources, including shedding loads to meet that peak day. So there isn't enough infrastructure in place to meet the peak day from a pure transmission standpoint. And that's why you get the systems, secondary is just not available sometimes. Most of the time it is. The "no bump" rule also devalues it, right? Because if you're a primary firm holder, you don't want to release your capacity to a secondary market, on that rare chance you might need it and you can't get it. So then you hold more back than what you need or might release otherwise.

Question: I'm not sure who this is for, I guess any one of the three gas representatives here. You talked about how part of this problem was a contracting issue. And my question is, is it a contracting issue or is it a cost allocation methodology issue? In ERCOT we've decided that the transmission system's role is to be the highway for commerce, the buying and selling of electricity. And so therefore, the cost of all upgrades are paid by all the users. You can translate that to some systems. And I have some familiarity with at least one IOU that's outside of ERCOT that uses participant funding. And the result is that no transmission gets built because if you want firm service, you've got to pay for all these upgrades and you're not even sure whether the number is valid.

But that's another issue. Let me back up. In Texas, at least parts of Texas, it's almost impossible for gas plants to get firm service without paying an extraordinary amount of money that renders it really uneconomic under any basis. Isn't one way to address this problem to view it as a highway system and allocate the cost accordingly among all users? You would do this under the theory, at least for power plants, that if (and we saw a little bit of this this winter) if the power plants can't run, you know, because of the gas issue (and that wasn't the major problem)--but if that's an issue, then you get gas problems because you've got pumping stations and gathering lines that rely on electricity for power.

MAN: It's an interesting question. And back as part of the restructuring of the natural gas industry, one of the things that FERC did was it moved to a model of incremental pricing for new facilities with a very strong presumption in favor of that. And one of the things that that enabled was it avoided the very protracted and contentious debates over who benefited and to what degree the costs should be rolled in, and to what degree you effectively needed to go through the equivalent of a rate case before the pipeline had the revenue certainty to proceed with construction of the pipeline.

And the model has worked very, very well in terms of being able to build pipeline capacity very, very responsively to the market and add that capacity and not get entangled in these debates over who caused the incurrence of those costs and to what extent does it benefit the existing shippers on the system, and whether they should have to pick up a portion of that. And so I think to go the way you suggest would be a very, very significant change in the natural gas model, and also, not surprisingly, would get significant pushback from a lot of the incumbent holders of firm capacity on the system who would say, "We've paid for what we have needed. We pay on an incremental basis when we need more capacity. And now all of a sudden, you're changing the rules to socialize all of this when in fact we're not the cause of the new demands that are being placed on the system."

So on the gas side, number one, that's the reason why we've got the model we've got. It has worked very, very well in terms of the ability to add pipeline capacity and benefit the market without having to get into these protracted rate disputes. And so I think that to go the way you suggest would be a real sea change in how we have approached the economic model for pricing new pipeline capacity.

Question: I have a question. I ask this purely from the electric system point of view because I'm not really a gas expert. What I'm hearing is that the infrastructure build-out is really where your focus is. And you guys have the benefit of knowing where your customers' needs are going to be. And the needs are related to things that are more flexible. The sun goes down, the wind comes up, and it's in those hours that your customers are going to need your help. And so I'm wondering if the customer base is so small compared to everything else that you have, that it's just not practical for you to change your model to be more flexible, or to be more accommodating. And then if I project that forward, there are going to be other technologies that are going to fill in the need for flexibility. And we're seeing that with micro-grids. We're seeing that with storage. We're seeing this with other technologies.

So I somehow sense the beginning of a very, very dangerous, at least for this business, set of converging conversations or disconnected conversations. I don't think the electric business is going to fundamentally change their business any more than you're going to fundamentally change your business. And you're going to start at 9:00. And they're going to start at midnight. And that's how it's going to be. So is it the case that this is such a small part of the gas business, we're not going to worry about it? Or are we going to really take on the challenges to change?

We did see this in the electric industry, you know, back in the '80s when everything was base load and that's how life was. And now if you're flexible, you stay in the market. And if you're old dirty base load we might not see you anymore.

So I'm just wondering, what's the context and what's the future? I'm hearing the challenge is more than infrastructure. It's the basic business model. Or is it just not big enough of a portfolio for us to keep this going?

Speaker 4: I think there clearly, and I'll ask Speaker 2 to supplement me, because he can speak to it from being inside of a major company.

I always start with the premise that a pipeline is valuable because what you move through it has value. If you have expanding markets for natural gas, that's a good thing for pipelines. If you don't have expanding markets for natural gas, that's probably not a good thing for pipelines. So there very much is a recognition that if you look at virtually any projection of where the demand growth is going to be in the natural gas market, it's going to be primarily in electric generation. So I think the industry very much recognizes that and is very much focused on it.

As we've mentioned before, we've got the cross tugs of, on the one hand, while that's where things are going, that's not who holds and pays for the pipeline capacity today. And so to what degree do you need to be responsive to your existing customers versus to what degree do you respond to where the market is going? And when pipelines have created and offered tailored or sculpted services to meet the needs of electric generators, typically the response has been that generators haven't signed up for it. And the reason they haven't signed up for it is that they can take the generally applicable tariff service and then count on the fact that most of the days of the year, there is sufficient flexibility in the pipeline system to meet their needs, even if it goes above and beyond what the pipeline is obligated to deliver under the tariff. Pipeline can provide a lot of flexibility so long as it's doing it on a nondiscriminatory basis.

And so that was part of the reason why in our presentations we made the point that really, to answer this question, you need to look on both sides of the equation. Because while we recognize the needs are there, if no one is willing to pay for what it takes to satisfy those needs, and particularly in the instances where satisfying that need requires some investment, then it doesn't make economic sense for the pipeline company to offer that. As we said before, we don't socialize the costs. We don't spread them on a rolled-in basis or in a kind of a "build it and they will come" model. It's very much a model of, if the customer is willing to pay for it, pipelines will provide it. But if you're going to rely on the inherent flexibility in the system, recognize that there's no guarantee that on that peak day the capacity is going to be there.

That's kind of the riddle that we need to solve. I think we recognize it. I think we realize where the market is going in terms of the demand growth. We need to answer these questions to get there, looking more broadly at what you're going to do to create the revenue drivers for the kind of investment you need on the electric power side.

Question: Let me just tease that out a bit more, because if you look at the projections of where we're going--and I'll pick the California ISO study that shows that high penetration solar is really going to change the nature of what we understand as the peak—they suggest that the value will not so much be in the middle of the day, because we've now got enough solar that those costs are starting to come down, but it's value around 6:00 AM and 6:00 PM as our mixes are changing, and it's very flexible and it's very available in those four hours, then what happens to your business model?

Speaker 2: I'm not sure that solar is going to solve the problem of peaks. Peaks can occur from all kinds of outages. If a cloud comes across and blocks out the sun, you're going to have a sudden peak need. You need to have an infrastructure to back that up, or you've got to shed stuff. And so to me, it becomes more of reliability issue. And the economist says, "Well, let the market sort it out." Well, no. If enough cars drive off the cliff because the brakes don't work, yeah, somebody will fix them. But I'm not willing to wait for the car to off the cliff. And I feel like that's where we're headed. What we need to do is take a real close look at where it is. Solar is not going to be the solution in the northeast in the middle of winter. You're not going to get the sunshine on those peak days. And if you do, it's going to be for a short duration.

I'm stepping over where I wanted to go. I think we are willing to change. It used to be that pipelines owned the gas and shipped the gas. And you basically took care of everything for everybody. You didn't have to worry about whether gas would show up. But we've been deregulated. We just transport it now. We don't own it. So to that effect, we have the scheduling cycles. And I mentioned that in the case of Tennessee and many other pipelines, we'll schedule on the hour, you know, if people can go out and get the supply. So that's a question. Would we more closely align our day with the electric group? Absolutely, if we can find a common ground.

And I mentioned for the pipelines and the producers, the issue is dispatching people in daylight hours so it's safe. And, you know, economically, why wouldn't you just automate your gas well so you don't worry about dispatching people? And the answer is, if we could economically do it, we would. I don't mind making the gas day midnight to midnight. It doesn't bother me at all. Except there's that human element and that reliability that you have to cover. So can the electric change?

I mentioned some of the gathering systems have 30,000 wells behind them. It's a lot of automation. If you have a few hundred mega-power plants, is it easier for them to switch their day a little bit? They don't have to align perfectly either. We just need to get close.

Building out infrastructure like gas pipelines gives you line pack and the ability to offer new services and be more flexible and meet those needs. I don't think gas pipelines are the answer to everything. But I think, like all of the electric options that are out there, we're a piece of that solution. And we need to work on the infrastructure and the timing. And certainly, we're willing to make the changes. We're willing to make tariff changes if we can get them passed and people will sign up for those rates. But usually we wait to be driven by the marketplace as opposed to being drivers, because of the economic model.

Question: I'm trying to figure out what the problem here is, and whether or not it's FERC. I've been in the business quite a long time. And I can recall when the industry told us that if we had open access, the pilot lights would go out and would take weeks to get back on again. So I have a couple questions. One, are there any actual incidents that we should, examine carefully, where the system has failed to deliver? And secondly, is this a FERC problem? Have we denied you the ability to charge proper tariffs or whatever? Is it a gas or an electric problem? Should we be reforming the electric tariffs? Certainly I'm not aware of anybody having firm gas transportation charges denied those in a capacity market, or having the volumetric charges denied in a bid into the energy market. So if that's a problem, let me know. I'd be glad to think it through.

I don't know why we don't want marketers to have information that would say, you know, get more gas to this place or that place. But that seems to have been raised as a problem.

And lastly, I think that the issue of the gas-electric timing needs a lot of thought, because, you know, there are certainly reasons why you may want to begin the electric day around 8:00 PM instead of midnight, or at 6:00 AM instead of midnight. Both of those seem to be more closely aligned with the cycle that you're interested in. But I'm not sure how much discussion there's been. And it sort of alters people's day. That gets to be a problem.

Speaker 2: Wow. That's a lot of questions. A couple points jump out at me, and I'm going to have to do some research. But I know when there is a major outage of a major power plant, they will not tell the gas pipeline, even the control centers, which power plant went down. That is a regulatory problem, I believe--the ISOs, the NERCs, and to a certain extent, even the power plants themselves are afraid to give me that information when I'm trying to figure out what's going on. I can see something going wrong and they acknowledge something is going wrong, but they won't tell me. And they tell us that's because of the regulator. I've seen it happen in the ERCOT region. I've seen it happen in NYISO And I've seen it happen in ISO New England. So is it the RTO ISO or the FERC, or one of the other groups? I'm not sure which. But there's a problem, in my opinion.

In terms of, whether we are getting the rates we need and whether that is a regulatory issue, I'm in a rate case right now. So I'm sure the lawyers would tell me not to say anything. But my experience has been--and we're still running 1940s vintage engines on our pipelines, driving compressors, which they're actually pretty decent machines. The golden era of mechanical engineering was in the '40s and '50s--but personally, I wouldn't drive a 1940s or a 1950s car to work every day because I care about the reliability. If it were up to me as an engineer (and I worked in engineering for a long time) I'd replace those machines. But we can't get the rates of return. And being in a rate case, it's very challenging when I explain to people why we need to do work and what it costs. And they say the cost too high. We're not going to support it. So we don't replace the machines. So I think there's a challenge there.

Speaker 4: Well in some ways, it gets to your analogy before about whether you wait for a bunch of cars to go off the cliff before you start thinking about the brakes. And I think that some of the examples that Speaker 2 gave in his presentation, where you saw the impacts of generators taking when not scheduled, and saw what that did to system pressure, and then you say to yourself, "OK, we're forecasted to have even more gas-fired generation on the system, and likely to be dispatched at higher capacity factors, and so are we going to see more instances where that is occurring?" To what degree do we rely upon the existing structure for the wholesale power markets and the capacity markets and things of that nature to begin to reflect that situation? Or do we step back and take a look at it and say, "OK, you know, given the trends that we see, you know, to what degree do we want to start to think ahead and answer these questions?" And, you know, that's the discussion that will have to occur.

I think our point here is just simply one of knowing that more gas is going to be utilized for gas-fired generation, knowing that pipelines are the interface between those generators and natural gas, and the ability to get it delivered and delivered at the quantities and pressures that are needed. We think it's important to highlight these issues and make sure that they're on people's radar screens. And then the stakeholders and the regulators will have to determine how and when to deal with them.

Question: Should we wait for you to file the tariff or, you know, what should FERC be doing?

Speaker 4: It's a good question, because as you know, nobody likes to be the guinea pig. Nobody likes to be the case that all of a sudden becomes the cause that everybody is focusing on. And then also, particularly if it is a general section four rate case, it becomes a free for all with all of your customers. And it's not just the level of the rates and the return. But there are lots of cost allocation issues and things of that nature. And do I really want to plunge into that pool?

And of course the other issue, and I talked about it just tangentially in my comments, was the issue of, when you come to these services, to what extent are these things that are needed and costs that need to be incurred to continue to have the ability to deliver a generally applicable service? In which case, all the other customers taking that are going to jump in and say, "Hey, I didn't cause that cost. I don't want my rates to go up." Versus, to what degree are you willing to say, "Hey, guess what? There's a unique set of requirements needed to serve this particular group of customers, and we're going to create a special tariff or a special service for them"?

You've still got the issue on the other side of the equation of whether they are getting the signals they need to say, "OK, I'm going to subscribe to that," or not. Given the level of attention that these interdependency issues are getting coming out of the Texas contagion last winter and whether that was unique or not, and other things, it seems as if some look at this on a more comprehensive basis that recognizes that how one market operates and how it's regulated affects the other, and vice versa, probably is in order.

Speaker 2: My personal viewpoint is that we need a tariff. And I don't know if we need the commissioners to help us. But there ought to be a special rate for power plants that recognizes the market price of electricity and the penalty as tied to that, so that the market gets a good signal.

Because when we have a general tariff--and right now, when we issue an operational flow order, and we put a penalty out there for people overtaking, the cost is $15 dollars plus the spot price of gas. For a small LDC that does not have unlimited profits, that could bankrupt them. For a power generator, and they're selling their power at $3,000 dollars into the spot market, it's a joke. They tell me, "I don't care what your penalty is, I'm paying it. I'm going to make so much money." And they take the gas.

So then as the director of gas control, my last resort is dispatching technicians when it might be ten degrees outside and there might be two feet of snow to go close a valve to a power plant because I can't take the chance that the automation is going to work on that cold of a day. So people are being put at harm. So in the end, if everyone recognized that this is a true economic problem--I think Speaker 4 would say that you can't ask one pipeline to step up and do that. This is a national issue. And it varies by region, but I think it really is a national issue.

Moderator: I think there's growing recognition at the Commission that we have to address it in our forum. But it could be that we wait 'til the results of the southwest taskforce investigation come out. But it's going to be a live topic in the next year. And I think everybody should be ready for it.

Question: This is very interesting, especially this last comment. It seems as if you have two sets of customers, gas customers and power customers. And the intersection here is pitting one against another. Right? You would not want to drop power customers. Therefore, the prices go to 3,000, and they're calling all resources to generate. But you wouldn't want to drop a gas customer. And weighing the difference, and not having a price signal that will translate realistically the shortage of each market to each other is the start of a problem.

Right now, when a peaker is built in a power market that's an ISO, they don't need firm transmission for the electricity side. So I think it's kind of interesting that both Speaker 2 and Speaker 4 have suggested that a solution is to try to get firm transmission for the gas side, which suggests really that the structure of both markets aren't really compatible. On the gas side, you want customers to sort of pre-pay. And you want to identify resources to customers on a long-term basis, and a firm basis. On the power side, we've moved away from that, where you have a highway kind of perspective, at least in Texas, for example, where capacity will be built when needed, and there is the ERCOT process.

I can look at the future and say, do we need more capacity? Do we want to have special zones? Do we want to put more in? In a sense, it's a different model entirely. And now we're intersecting them. So my question has to do with whether we should change fundamentally how the gas market is run. Should we have an independent operator that prices and re-dispatches, in a sense like the power markets, and that would also have a function of planning? It would allow El Paso to build pipeline capacity when it's needed, and essentially get a rate of return without having specific customers in mind, because the ISOs can essentially re-dispatch hourly. And then the last point is, if there are going to be two models, two ISOs, why not the same one? So that's my question.

Speaker 4: You're a central command and control guy here. It's an interesting question. But I think there are couple of responses, one of them being that answering these questions would be a lot easier if the electric load was the only customer on the gas system, or if it was the predominant customer on the gas system, which is not the case. And so we've got the very practical problem of how do you deal with the gas LDCs and others out there who currently hold all of the firm capacity? As I said before, their pushback is going to be, "Hang on, I'm the one who paid to build this system. I'm the one that's provided the flexibility that everybody else is utilizing. And don't go overturn the apple cart if it's going to put me in a worse position." That's a practical concern that you'd have to address if you wanted to somehow try to integrate the models in that way, and particularly to emulate what's been done on the electric power side.

The other thing is that I think we've got a model that at least up until now and until it's disproven, has been a remarkably successful model in terms of the ability to add pipeline capacity. You know, in the last decade, about 16,000 miles of new interstate natural gas pipeline capacity was added. Clearly less than a thousand miles of electric high voltage interstate transmission was added. And you can push back on me and say that you're comparing apples and oranges. And I may be. But guess what? If pipelines were apples and electric transmission was oranges, you've got a heck of a lot more apples than you have oranges.

The other thing is that our experience from back before the Commission went with the incremental pricing model was that you had tremendously contentious and protracted proceedings over what the right pipeline route was, and who built it, and all of that kind of stuff. I think going back to either the late '80s or early '90s, there was the northeast open season over who would build capacity to meet growing demand in the northeast. And it became a terribly complex, contentious proceeding where--particularly if you're responding to a need in the market--probably about the only thing it guaranteed was that you're going to respond late to that need in the market because you're going to become so bolloxed up in the administrative litigation, not to mention the judicial review that might follow.

And the other thing about it is that on the gas side, the market overall has benefited from the competitiveness between pipeline companies in terms of recognizing market opportunities and responding to them and the market voting with its feet or voting with its dollars in terms of which of the competing projects it's going to choose to sign the precedent agreements with that then provide the basis for the Commission to support determination of need.

And so I think there's some practical realities in terms of saying you wanted to seriously look at that suggestion. And I think you'd have to overcome some very strong presumptions in terms of the gas model and how well it has worked to date in order to say that you really wanted to go to something that was totally different from what we have and from what has worked.

Speaker 2: Real quick, I just want to add, I think in the electric model, and we've talked about this, it's an N plus one model. You have all these backup power plants for these other systems that are out there. On the gas pipeline network you do not have backups. And so I'm asking for people to hold a small portion of their potential burn as firm, knowing that those power plants actually are required. Because no mechanical machine runs 100% of the time. Everything's going to go down and need maintenance, best 90%. So you need that 10% reserve. I think we need to have that 10% reserve on the gas pipeline network, especially for the pipeline in the summer, in the New England area, if you've got to meet that peak hour.

I don't know that I'd want a command and control center. But I would love an air traffic control center that looked at the gas and electric grid and would send signals to the control centers, of, I see something going wrong here. Are you guys aware of it? Just free information, nonprofit, but looking at both networks.

And, you know, the independent system operator is a good idea for the pipelines. I'm sure it wouldn't be real popular with some of the industry. But I think there could be better coordination between the pipelines. Informally, we have a network right now. And I don't know if everybody knows this about the gas industry. But we have a rule among all of us, and we've always honored it. When something fails, when someone is in trouble, we always, always cover each other. We all know each other on a first name basis. We all have each other's phone numbers. We always cover each other to the extent we can. But that's always happened on an informal basis. And you're relying on being able to get hold of those people. But I know all of my counterparts at Williams and Spectra. We always cover each other. And it's only worked because of the relationships we have. I don't know that people want to rely on that in the future.

Question: This has been very helpful to me, because I've been looking for the missing market here. Let me feed back to Speaker 2 what I think I heard him say and see if this is correct, and then see if this implies what the answer would be there. I can buy firm capacity which is scheduled on a daily basis as ratable capacity. And I'm looking ahead today, I can sell mine to someone else. And then he's got it for the day, and so on. So that problem seems to be, and the price that we do this at is between us, so we can do whatever we can do. So that sounds OK. So it sounds to me like it's an intraday problem rather than, you know, a day-to-day problem. And for the intra-day problem, it sounded like I heard price cap jump into the story. So you get into a situation where people are all coming online all of a sudden all day long, and they're taking more than you had expected. And now you've got to stop them. And you impose a penalty which is capped. And for a lot of people, the penalty, which is capped, is chump change. And so then they're ignoring this. Now you're not getting the incentives right.

And so it sounds to me like the problem is that price cap in the intra-day story, and if you want to get prices right, what you need is something that gets rid of the cap and has a more market-like effect, and if the LDCs don't want to sell their capacity, that's their business, whatever their reason is. And if the price goes to many multiples of $15 for the collector guys, and they eventually get choked off, even though the price of electricity is $3,000 dollars, that's going to create a hell of an incentive for somebody to get into the business of buying firm capacity that I could sell into that intra-day market, because I could make--I have a business model I've been working on here actually, which is to buy firm capacity...

Comment: That's what we want.

Question: So it seems to me the problem is the intraday price cap on scarcity rates, essentially, would be a way to describe it. Am I understanding this problem right?

Comment: I think that's a big part of it.

Speaker 4: Yeah, I mean, I think as Speaker 2 pointed out, the challenge that we face is that if the service is being rendered under a generally applicable tariff, and if most of your shippers are LDCs and others, they're going to go ballistic when the $15 penalty becomes $3,000 dollars, or whatever it will take to incent the behavior in response to the price of electricity. So it kind of gets back to that...

Question: If they have capacity, firm capacity, if they're using it, we don't charge them a penalty and...

Speaker 4: I know. But let's say that they engage in some behavior that causes them to incur a penalty in terms of overtakes or doing something that's not permitted under the tariff.

Questioner: Good!

Speaker 4: I think politically, and in terms of the stuff that FERC ultimately would have to resolve, you'd have LDCs coming unglued, saying, "Guess what, my $15 dollar penalty just became $3,000 dollars, and still, all I get is this cheap T-shirt." I mean, it just--you know? That's the practical problem if you've got everybody taken under that generally applicable tariff and affected by that. By the same token, if you could somehow segregate it and say, "OK, hey, you know, for the generators or others who are..." I don't know. You hit upon a good point. I'm just pointing to what would be some of the practical challenges of getting there.

Questioner: Well, if you let people take expensive stuff for free, you're going to have a problem.

Question: I want to come back to an earlier question. We, as generators, take this topic seriously and have already started to engage regulators and our gas friends. But I didn't think I heard an answer to the question which is sort of the predicate of the whole discussion--

What kind of data is out there on the extent to which this full-day full-firm, there's no room for anybody else situation happens? I haven't heard anything said about that other than sort of a few anecdotes. Where could we look to see the extent to which this is actually happening on a sufficiently regular basis to be as dire as some of the conversation suggests? Because I think it goes to what makes sense as a remedy.

Speaker 2: If you're watching prices, you'll see the prices go through the roof. So you'll know when something is going wrong. And if you ship on a pipeline, we send out a notice to all of our shippers about every four hours about whether the pipeline is going long or short and what the available capacity on each major segment of the pipe is. Many other pipelines also post their capacities, real-time what's available.

Speaker 4: But in answer to your question, have we yet, on a consolidated or aggregated basis, pulled this together? I think the answer is no. I mean, it tends to be now pipeline specific. And it tends to be market and region specific. But I think you make a good point in terms of asking, what are you looking at? I mean, what are you defining as being your, "close call" or whatever that gives rise to concern. I'm not sure whether Speaker 2 made the point earlier, but absent the physical inability to do it, pipes will typically bend over backwards to make sure that the gas is going to get there, even if it requires them to do things that go above and beyond what the tariff requires, so long as they're doing so on a nondiscriminatory basis. So again, it probably needs to be defined as something that looks more like a close call than actually a crash, because the incentive is to avoid the crashes at all cost. But you do make a good point in terms of saying, to what degree can and should it be looked at on a more aggregated basis to illustrate the issue?

Question: This is a question directed really to the pipeline guys, too, to Speaker 4 and Speaker 2 in particular, on this. One comment and one question real quick. A lot of times a lot of gas-fired generators, they don't take firm capacity, but what they're doing is they're firming up their generation with a backup fuel. Generally it's going to be number two fuel oil. Now with the utility MACT rule coming out, there's going to be restrictions essentially on the use of fuel oil to 10% of your total heat input over the course of the year. That's at least the thinking that's in the proposed utility MACT now. So the ability to firm up generation is going to be limited, which comes back to Speaker 2's point. Maybe a lot of these generators need to take firm transportation on the pipelines in order to firm up that capacity.

But let me follow-up on the previous comment about incentives, because I think the comment hit on something there. Let me extend that. Not only could we potentially see a market-based penalty, you know, in the case of the operational flow orders, but let's now take that pricing down to the LDC and their customers at the retail level, where all of a sudden, if we have an intra-day problem, should we be thinking now at the LDC level about dynamic retail rates based on the conditions on the pipeline if we've got issues on the electric grid, and that's driving prices? Should that be then reflected to the LDCs on the interstate pipeline system and then transferred down at dynamic rate, down to the retail level so that retail customers can say, "You know what, I'm willing to let it get a little bit colder on a winter day today, because I'll save a lot of money doing that?" And the LDC can save a lot of money doing that. It's almost like we're talking about demand response, but on the gas pipeline level. In some sense, we're talking about synchronizing the gas and electric day, but we really need to think about synchronizing how we price out these commodities so that they're very much the same on both the gas and the electric side. So I just want to get some comments on that and thoughts.

Speaker 2: I think that's the solution. I live in Houston and whenever I go in a restaurant and the door is held open and the air conditioning is blowing outside, I close the door, because they're not paying the real cost. We've got to push the costs down, down to the retail level, if that's where I heard you going.

Questioner: That's precisely where I was going. But it solves the incentives problem, actually operationalizing the idea of the market-based penalty. Rather than $15 dollars plus a spot price of gas, it's the spot price plus whatever the market will bear, very similar to what we do today in the capacity release market. I mean, what is the price of capacity that's being released? And if an LDC is willing to release that capacity to generators, you know, at that price, then they can also benefit their ratepayers, you know, at the LDC level.

Speaker 2: And that's huge, because I know some LDCs have as much as a billion cubic feet of LNG behind their city gates. And when we were having this problem this winter, the reason the system didn't crash on December tenth (the date on that slide I gave you) is because we called some of the LDCs and we said, "Dudes, we're in big trouble. We need you, if you have LNG or propane or something else available, to bring it on." I can remember being on a pipeline a few years ago where we sent a note out that was like, burn whatever you have, even if it's firewood. There have been a few instances. I hate to see notices like that. Usually control room director to director, we cover all of these things. And shame on us for having done such a good job and preventing the system from going down, because now we've got a lot of people taking stuff for free.

Question: I just want to respond to the earlier comment on the levelized cost of electricity, and how it's not very useful. We do use that as a snapshot, a starting point. And to capture what you described, daytime and nighttime differences, we look at the cost of serving the next unit of load, like the next megawatt of load with, say, a 60% load factor. And you start with the base case using gas as a baseline to serve that, taking into account the difference between daytime and nighttime, and also seasonal changes of the load. And then you compare that with wind plus gas, solar plus gas, and nuclear plus gas, and so on, and use that to really strip out the gas and compare what's the true cost. And the result is that it doesn't quite change the premium of nuclear versus gas much. But as I showed yesterday in the bus bar chart, the difference between wind and gas expands. It goes substantially up. And for solar, it does go up as well, not as much as wind, but for PV and a little less so for CSP. So I agree, that showing the levelized cost is kind of a simple way...And there are, you know, second and third layers of analysis that will be used.

Speaker 4: Can I make a quick comment? Let's compete on 20-year PPAs, too. I mean, sure, some of these cost curves are simplistic. But there are also factors that would flip that the other direction. You know? I would love to see a lot of other generators try to lock in a firm fixed price for 25 years.

Questioner: We do actually also track PPAs. They're substantially lower than the localized cost that we show. PPAs, you know, reflect a cost of the developers or the producers that do not reflect a lot of other costs. And also PPAs typically or all of them include today's subsidies. I just want to clarify. All our cost analyses do not include today's subsidies. These are costs, whether they're borne by the developers or by utilities or by taxpayers or other socialized subsidies.

Question: I'd like to follow up with the moderator actually on something he alluded to, the investigation to the southwest and ERCOT incident in February. And it's really the converse of the question asked before the break. That is, in markets like PJM, the generator that wants to be a capacity resource needs to have sufficient transmission to pass the deliverability test. In other words, it needs firm transmission, or it cannot interconnect as a capacity resource. If I understand the presentations, if all gas-fired generators that were capacity resources in the markets were required to have firm gas transportation, then that could not be handled right now without significant expansion. So I guess the question is, what if one of the recommendations, and it's been bantered around by some people who may or may not know the facts as to what happened, what if the RTOs have a rule now that to be a capacity resource, you have to have firm fuel, whether alternative fuel, or firm gas transportation? And I'd also like Speaker 3 to comment on that. What would be the result for the industry?

Moderator: We were hoping that we could get some reaction from RTO people on that subject, if we could get to it.

Comment: From our standpoint, it would obviously have an impact on generators, because that's not the requirement at the moment certainly. Although it raises some questions about how many days of fuel supply you would have to have. There's a lot of specifics you'd have to get into if you were going to try to go down that road.

We haven't seen the issues that Speaker 2 has been referring to. I think all of us generators have been generally able to get comfortable that we manage that risk and that we can come on and provide the capacity resource we're obligated to provide through a combination of buying in the secondary market, having some interruptable supply contracts, having backup fuels. So we do a lot of different things. And we have not seen the signals, at least in our business and for our plants, that would say, we think we need to go down that road, which would be a fairly extreme change to how we do our business and could add significant cost to both incumbent generation and anything we're going to try to build and bring onto the system that would be new, so...

Comment: I just wanted to react to that very quickly. It's certainly something that we've talked about internally--should there be a firm fuel source to ensure that this capacity resource is going to be deliverable when we need it? To this point, though, it's not been a requirement.

If you think about the incentives, especially within the RPM capacity market, you have an incentive to try to diversify your portfolio of actions. You might have a little bit of firm transportation, you might have some backup fuel, and so on. Because if you're not there when you're needed, you're going to take a hit on your EFORd (equivalent demand forced outage rate), which is going to eventually reduce the amount of unforced capacity that you can get paid for in subsequent auctions, in the base residual auction. Moreover, if it's during peak periods, there's also going to be additional peak period forced outage rate penalties that you may incur. Now, we can talk about, are the level of those penalties appropriate or not? That's a subject that we could get into. But there is at least in theory, there's an incentive for people to take the least cost actions to ensure that they have fuel so they can deliver on that capacity obligation.

Speaker 2: I want to add a note. Unless you match that penalty on the gas side, all you've done is transfer those penalties to me. They're going to steal from the gas pipeline network.

Comment: Hence the reason I was talking about operationalizing the disincentives the earlier questioner was suggesting.

Comment: I would just suggest people look at the trend in NERC violations and what happens to dropping load or even planning to drop load. It's moving in a much more stringent direction. And again, I don't know what's going to come out of the investigation. But that kind of comment has been bandied about. And the people who bandy it about may not understand the fundamental infrastructure issues.

Comment: Just a very brief comment. The discussion about market-based incentives I think makes perfect sense. The one thing I would add is that right now, the incentives are not really there to perform for capacity resources. That is, the worst case scenarios, we don't perform at all, you only lose half a payment. So we need to start thinking about getting incentives right across the board. So I wanted to leave that comment out there.

Moderator: This is a much larger discussion that we're going to be having a lot more of.

Question: It seems to me just from listening that, especially what Speaker 2 said about his experience in both, as a pipeline and a producer, that the communication issue is the biggest issue that we don't seem to be addressing squarely. I'm stunned to find out that there's a rule somewhere that prevents you as an operator from knowing the details of an outage. That just is appalling. And, I mean, if it's a market affiliate rule, then we need to re-address that. My first question is, do you know what kind of rule that is? And second one is, what can we do structurally to make the communication between gas and electric more like it is in the pipeline community and in the pipeline producer community?

Speaker 2: I don't know the source of the rule. I can tell you, when I talk to my counterparts on the electric side, they can't tell me what happened.

Comment: Can I just help clarify that again? Right now, it's an RTO rule. We've been arguing for some time that there's no need to keep outages secret for lots of reasons, for electric market alone reasons. And certainly the point you've made only adds to that. Right now, it's an RTO rule, it has to do with confidentiality. It's been treated as market-sensitive. I certainly don't think it should be. But the RTO and the RTO rules on confidentiality and the release of information--start there.

Question: And the second part about structural change to communications, Speaker 2?

Speaker 2: Having the open clearinghouse I think is something that's missing. And the concern is market dynamics, that someone having that information would manipulate the market. We see the pipelines over-nominated, people intentionally nominating flowing gas that they know they cannot take and they're doing it to capture market. And so I understand why some of these rules got put into place. Our challenge now is to figure out operationally how to take off those handcuffs so that the system can work the way it was intended to.

Question: Back on the topic of levelized cost comparison, first a clarifying question for Speaker 1. In your slide, where you showed the levelized cost comparisons of wind versus, you know, gas, coal, nuclear, etc., did you include in the wind the cost of the backup generation or the cost of the transmission, say, from South Dakota to New Jersey, whatever it's going to be? And at least to a substantive question that is, acknowledging that these levelized cost comparisons can sometimes be simplistic, but from a policy standpoint, it's incredibly important to try to get some kind of accurate comparison. So for the panel, what should go into these levelized cost comparisons if we really want to try to get, from a policy standpoint, an accurate comparison of wind versus coal versus solar versus gas, and you can try to make some positive decisions?

Speaker 1: The slide I showed was from Lazard. And they do factor in the production tax credits. So you could put two cents on that to show it without. I think Speaker 4 from Session Two said her slides were without PTC, which is part of why they were higher. So, you know, you could do it either way.

In terms of integration charges, that was not factored in. Our slides showed \$3 to \$5 dollars a megawatt hour. So you could say that's, you know, roughly 10% added cost. Or you could include, if you wanted to on that. Again, I would also argue that if you were doing new nuke or any other large fixed baseload plant, you should factor that in as well. It's not just wind that creates a need. Why do we have, you know, pump storage? It's because of nuclear. So other resources have integration charges.

Transmission was the other cost you mentioned. If you're looking at sort of a region--Texas is one case--they're building out transmission to integrate more wind. You could look at the cost of that. I would not want to assign 100% of the costs of the new transmission to wind. I know one meeting attendee would. He and I have had a lot of fun debates about that one. But, you know, let's say you took half of the CREZ lines and allocated it to wind, you might get, you know, 10% cost adder for that. So if you wanted to add a couple of those cost adders, you could look at it that way. I don't think we're going to see transmission from South Dakota to New Jersey, either. So in terms of what type of transmission we're talking about, I don't think we're going to be seeing that type of transmission cost.