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SEVENTY-FIRST PLENARY SESSION

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Rapporteur's Summary*

Session One. Making "Energy Only" Markets Work

Alberta has an "energy only" market. It works in practice. But can it work in theory? How is Alberta different from other RTOs? The Alberta Market Surveillance Administrator State of the Market Report describes a generally efficient market. Recent Brattle reports for Texas and Alberta paint different pictures. The Alberta design uses a single price model that has failed whenever tried in U.S. RTOs. How is this single price sustained? What works here? What doesn't? How do market prices reflect scarcity conditions? Why is there no apparent "missing money" problem in Alberta? What light does the Alberta experience shed on the policy discussion in Texas? There are important features in Alberta. Alberta allows economic withholding and portfolio bidding. Is this compatible with a competitive market? Can this continue? The debate over energy-only markets provides an opportunity for comparison across different systems.

Speaker 1.

Thank you for the introduction. It's good to be back here. We did do quite some work here in Alberta, and in 2010, we were first asked to review whether the market was sustainable from an investment and resource adequacy perspective, or in academic circles, it's often referred to as the "missing money" question, whether there was missing money, or whether the market prices were high enough to sustain investments. And we did find that the market prices could sustain investments, and that the fundamentals of the markets in how things were moving relative to reserve margins and so on actually worked quite well, surprisingly well. We were also asked to identify a number of challenges, like coal plant retirements. That was a big fear here in Alberta in 2010, because of new legislation, like in the US. And we found that those challenges were in fact manageable.

A lot has changed over the past couple of years, and last year the ISO here asked us to update our resource adequacy assessment, and we did. And we reaffirmed our findings. So for most of the presentation I will walk you through what we

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found and will also do a brief comparison to Texas and a couple of things like that.

A little bit of background. The Alberta market is the smallest North American deregulated power market. Installed capacity is about 14,000 megawatts. There are six major generators, plus a large oil and gas cogeneration sector. There is high load growth, at least by US standards, where load growth is generally below 1%. I think the long-term average is about 2.7% here. And that's surprising, at a very high load factor. It's an 80% load factor, because its mostly industrial load. The summers don't get that hot. There's not a lot of space heating. So unlike other systems, including other Canadian systems, this does make for a very high load system and very high system utilization. Also, it's very sparsely interconnected with neighbors, only about 800 megawatts, so that's far less than 10% of the market.

In terms of the design, for those of you who may not have looked at this yet, it's a real-time energy-only market. There's no day-ahead market. It's settled hourly after the fact, ex-post. There's a single price for the entire market. There's no zonal or nodal concession pricing. There's no centralized unit commitment. Generators just commit themselves and bid into the real-time market. This is a simple merit order dispatch. It works in real time. And there are ancillary markets for operating reserves. They're not co optimized with energy markets. It's a simple design. But because of load growth and retirements, a fair amount of investment is needed. The annual capacity additions averaged 450 megawatts since 2000, and that has been a pretty constant stream. So, basically, even though it's a small market, one sizeable plant a year on average has been built. Looking forward, it's a bit more, because of coal plant retirements. We estimated it's about 530 megawatts per year that would be needed through 2030.

Transmission is a big part of every market design. In the Alberta ISO, unlike other power markets, they have a mandate to plan a mostly unconstrained system. So under normal operating conditions, 99.5% or so of all generation has to be deliverable from a long term planning perspective. With contingencies, it's going to be less than that, obviously. The transmission system is owned by private transmission owners, so the ISO does the planning and the needs evaluation, but the system gets actually built by the transmission owners. There are no transmission rights. There's only hourly opportunity service. There are no generation or transmission interconnection connection charges or rights, so a new generator basically just interconnects. They might have to pay for the needed interconnection facilities, but there are no fees for network upgrades the way this is handled in many of the US markets.

So how can a single zone market work? Because people have tried that in other places. There are a few things that work reasonably well in Europe, but even there you usually have multiple zones. Well, it's a small market, so the Alberta zone is smaller than each of the two zones that we had in California, and they're smaller than each of the zones in Scandinavia. And there are very few load pocket constraints, so there's only the Northwestern Area, that's about 8% of load, that requires constrained-on generation, and that is handled through contracts, basically. They're called TMRs, transmission must run contracts. There is also "dispatch down service," so the other generators that would be in merit order but for the constraint on generation, get paid for dispatching down.

Most of the constraints are generation pocket constraints, so those are generation pockets from generation rich regions like the southwestern area where there's a lot of wind interconnecting to a system that hasn't yet been built up, or the Ft. McMurray area, that's the oil sands area, where there's a lot of cogeneration that at times is export constrained. But these export constraints are only binding between 200 or 1,000 hours a year, and the downstream market is about 80-95% of the market. So most of the market is unconstrained.

So the way the clearing price works, it's actually set by the last in-merit dispatch. So in that setting, it means it reflects the last unit dispatched in the downstream markets, so you basically have a single clearing price that is the correct price for the downstream market, in that, as I said, these are just small generation pockets. It's really 85-95% of the market, and during most of the year, those export constraints don't even happen. So the single zone construct is not as daunting as in some of the US markets, where transmission constraints were much more binding. Of course, in part, this is due to the setup that the ISO is in fact planning and building transmission to keep the system largely unconstrained.

So the challenges that we looked at in terms of market sustainability here were, first, the low gas prices. There was a fear that low gas prices would get coal plants retired prematurely, that the margins were just too slim, even for gas prices. These PPAs, these long term contracts that were signed when restructuring happened, they're expiring now, so people feared that as these restructuring contracts expire, there wouldn't be enough money in the markets to keep the plants around, and if there were a lot of simultaneous retirements, that could really be a challenge.

We aren't concerned about these challenges. They don't affect the fundamentals as much as we thought, and there's enough money in the market to comfortably keep even the old coal plants profitable until they have to retire for environmental reasons. The environmental regulations are very interesting, because there are some pretty strict federal Canadian regulations on coal plants. But in the US, the regulation is that there's a compliance date, and by 2017, everybody has to comply. The Canadian regulation says, as a plant reaches an age of 45 years, it has to comply, which means the impact of the regulation is spread out with the age of the plant, which doesn't create the cliff that the US markets have been facing. But even in the US market, like in PJM, where you have 14,000 megawatts of announced retirements, it has barely made a blip in terms of resource adequacy.

There's a lot of wind coming onto the Alberta system, not as much as in other places, like ERCOT, but the fear was, does wind really suppress the market clearing prices, and does that create a missing money problem? And it has not.

And then there's always the question, if you interconnect the market more with neighbors (the neighbors are cost of service regulated, with utilities who have a separate stream to pay for generation capacity costs) wouldn't that just take money out of the market and undermine the investment incentives in Alberta? That could be a problem if there was a significant expansion, but at the current levels, even if you doubled that interconnection, we do not see a challenge here.

The gas price is important. Of course you know that from the US. But, as you see on the dark blue line (in this chart), gas prices were well above $6.00 until 2008, and were projected to rise into the $8.00, $10, $12 range by 2011. When we first looked at this, prices were already pretty low, and people didn't think they could get any lower, but now, two years later, prices are lower still. And does that really take money out of the market that would make investments more difficult? And I'll show you in a moment what has happened.

But the other challenge that was brought up in our review, and that is a challenge that has been brought up everywhere, is this. When we looked at PJM's capacity market, the first thing we heard is, “Nobody can finance a power plant with annual capacity prices like PJM, that you really need long term PPAs to build new plants.” When we looked at the ERCOT market, everybody said, “Nobody can build a power plant in an energy-only market without capacity payments.” Same thing here in Alberta, people said, “There are no PPAs. There’s no long term forward contracting. There’s no capacity payment. You just can’t build power plants.”

But what it really means is that you can’t project finance power plants the way you could if you had PPAs. What it requires to make that work is a lot of equity. The experience with Panda in ERCOT shows that you do need to put in 50% equity. But it’s a capital-intensive industry. If you look at the oil exploration sector, they’re having a lot of equity to put into oil drilling and shale oil and so on. So what we believe is that there will be enough investment, but it won’t be the historic PPA-sponsored project financing that we see. So you’ll have a shift to investments from larger, more diversified companies who have the balance sheet to support the risk of merchant generation.

And so this chart shows what happened to the reserve margin outlook. The light blue line is what that outlook looked like when we first started looking at this two or three years ago. And you see that light blue line is pointing down pretty quickly. At 3% load growth you reduce the load margin very quickly. But what has happened since is, you shift from the light blue line to the dark blue solid line. And you see that, just based on the plants that are under construction now, if we take 15% as a target reserve margin, you’ve got enough to get you through 2015 or 2017, and the plants that have already received AUC approval easily get you to 2018, 2020.

Now, the interesting thing that I find is that dotted line for 2013. You see that the level of what was announced in 2011, which is what has been announced for possible development as of now, has shifted up tremendously, and if everything that has been announced was going to get built, you would have a 50% reserve margin. So what does that mean? Well, that means most of these plants can’t get built. So if you hear people say, “Well, we can’t build plants,” well, many of those plants shouldn’t get built, because it would be too much. So what you will see is that only the lowest cost parties who have the best sites, who have the best technology, who have the best financing arrangements, can make it, and they will. And everybody else is sort of a little bit out of luck until the system gets tight again, and you need to build some of the higher cost plants.

So how do we know that a market is sustainable? We try to look at the missing money and see what different technologies are earning looking forward. And one thing we did is we looked at market heat rates, and the market heat rate duration curve, because that is really what drives a lot of the margins for new plants. And you see the top chart there, the blue lines, those were the market heat rates in 2009 and 2010. Interestingly, gas prices have been declining since then, but you see that the market heat rates during the top 20% of all hours have actually shifted up quite a bit. What happened was that generators changed their bidding behaviors, and as a result, there were more higher priced hours during the top 10% of all hours or so, and, despite the lower gas prices, prices during the top 10% of the hours have increased. Prices during the other 90% of the hours have actually slightly decreased. But as a result, the margins that new plants can make in this market have stayed about the same.

I thought it would also be interesting to look at the price duration curve of Alberta compared to ERCOT. And this is a very striking picture, in my mind, because you see that in ERCOT, prices rise above $500 a megawatt hour during about 1% of all hours (this is in 2011, the highest priced year in ERCOT in recent history). In Alberta in 2011, prices were about $500 during about 4% of all hours. And that difference between the blue curve and the red curve, that is about equal to the missing money. Alberta has a $1,000 price cap, so it's a very low price cap. But you can see it takes a lot for the half percent of all hours, where the ERCOT prices are above the Alberta prices, to make up for the other 7% of all hours where the Alberta price is about the ERCOT price.

So we looked at generator economics, and we took the price duration curve for the last four years, which is an average of 2009-2010, where heat rates were a little bit lower, and 2011-2012, where heat rates were a little bit higher. So we said, if the market heat rates going forward are on average what we had over the last four years, this is what the prices would look like, and the red is the average price. The blue dashes are the median price, and the bars are the ranges from highest to lowest, because, as you know, high prices are not seen during much more than 5% of all hours of the year. And if you were to dispatch power plants into this price duration curve, this is what the margins look like. The green line here is the cost of a new plant. This is a combined cycle plant here. And the solid bars are the margins, the contributions to fixed costs that combined cycle would be making in that market going forward, and you see, these are the average conditions. But you have a pretty big range depending whether you are on average in a 2009/2010 heat rate world, or whether you are in a 2011/2012 heat rate world. So there's a big uncertainty around this, and the difference between the green line and those blue dots isn't as big as it seems, because there's probably some risk premium, and so on. But you also see historically, most of the years, a combined cycle plant would be making less that its average investment cost recovery rate. But in some years, it has made more. 2011/2012 were good years, and maybe that's what has encouraged people to make more plants for these investments.

But looking forward, the economics of new plants actually look surprisingly good for gas plants. Not so for coal, but that's really not surprising. And it would be very hard to justify new coal build with the gas prices that you have right now, plus environmental risks. But prices, even for coal plants, are high enough to keep existing coal plants in the market. So it's not going to be likely that any of these plants would retire just because their current PPAs are expiring. And if you look at some of the different technologies, like gas, combustion turbines, combined cycle units, and cogen, cogen is the most economic, because a lot of the capital cost is paid for by basically what you would have to pay to produce the steam anyway. Wind and coal are not in the market, just based on energy revenues, but obviously wind in particular has other revenue sources.

We did make an important recommendation, however, because a lot of the peak pricing that you see in Alberta is driven by generator bidding behavior, and we're not certain that that pricing is very predictable for other market participants, because if generators change the bidding behavior, or if the market surveillance administrator changes the mitigation rules, that missing money problem could return pretty quickly, or there might be unexpected retirements of big coal plants. We've seen Sundance, 800 megawatts being knocked out a couple of years ago. So there are some uncertainties, and we did recommend that the price cap should be increased, and a scarcity pricing curve, very similar to what Bill Hogan has proposed in ERCOT, should be considered, because that would create a safety valve that would add money to the margins should the reserve margins drop. But at the current reserve margin of 17-18%, that scarcity pricing curve and the higher price cap would have no impact whatsoever on consumer bills, because it's just not going to be happening very often.

So to summarize, we have found that the market is sustainable, that it retains existing resources, that it encourages new investment, and as long as there aren't any wholesale changes to the market structure, the mitigation environmental rules…obviously there's a lot of pressure on Alberta to improve its environmental footprint and so on. And so it is very easy to inadvertently mess up the market design and create a sustainability problem. So that's why we say it remains sensitive to these challenges.

But what is it that are really the sources of Alberta market sustainability, when other markets like ERCOT have a harder time with dealing with a missing money problem? Well, one is that scarcity pricing, whether it's bid based or based on true scarcity, is working reasonably well. As things get tighter, prices go up. But even as gas prices decline, and generators could adjust their bidding during those high price, high load hours, that has worked pretty well. There aren't a lot of long term contracts allowing generation financing, but we talked to some investors, and if people have the equity, they can build plants. And there is, of course, a very favorable economics for large cogen plants, because there the investments in generation are not driven by the need for generation, but by the need for steam. The other factor, though, is that Alberta, with an 80% capacity factor, is close to that source scarcity point during many more hours of the year than Texas, where it really gets tight only during the summer when it's really hot. Out of an 80% load factor, you actually see $1,000 prices spread throughout the year. All you need is a big power plant to shut down unexpectedly, and you have that pricing. But the last reason is, there is more permissive market mitigation. There are very well-specified Offer Behavior Enforcement Guidelines, and they allow for what economists would say is unilateral exercise of market power. It's fine to economically withhold, as long as you do it with your own portfolio, as long as there's no tacit collusion, there's no actual collusion, and you're not trying to do it to handicap competitors. There is the risk of prospective intervention if efficiency loss is documented. So I think people are hesitant to go too wild. And what we've seen with the bidding and pricing behavior is that prices hover just above what you need for new entry. So I think this is quite encouraging. And given that it's a small market, I think that it's a model that really works much better than what most people would anticipate.

We did, however, have some recommendations that this needs to be monitored, simply because it could change pretty quickly. There is, of course, the regulation of retail access that is basically default service that might impact some of the contracting. One has to be very careful with making inadvertent changes to the market design, because a lot of damage can be done very quickly to markets, and as we said, we did recommend that just as a safety valve, in case you need it in the future, even though it doesn't make that much difference right now, scarcity pricing and a higher price cap would make the market even more robust.

Question: Thanks. I didn't quite understand all the issues with why the prices in 10% of the hours are much higher. Because it sounds like there were three or four factors, but what was the main driver that changed the bidding behavior that pushed those prices up?

Speaker 1: Well, the bidding behavior did change, mostly after the MSA clarified the bidding rules. And so I think, despite the declining gas prices, prices during the peak hours went up, and I think that's mostly due to higher bids for the last incremental capacity from generators. But the reason why Alberta looks so different from ERCOT is not just because we allow generators to bid higher, but because with an 80% load factor, the system is closer to the system peak throughout the year. It's a winter peaking system, but last summer you had a load shed event, because several generators were out, and a heat wave was coming through, and so the summer peak is very similar to the winter peak, and there's not a lot of lower load during the shoulder seasons. So all you need is one big coal plant to have an outage unexpectedly, and you hit the $1,000 prices. So you have higher prices more often here in Alberta than Texas, and it's a combination of these factors.

Question: Are there additional environmental controls coming for the coal plants, or are the retirements just mainly due to the gas prices?

Speaker 1: Obviously there are a lot more knowledgeable people in the room than I am on the specific regulations, but there's a federal Canadian regulation that requires coal plants, as they exceed 45 years of age, to basically have an environmental footprint that's no worse than a combined cycle unit. So that basically means you can't get there with a coal plant unless you do carbon sequestration and all kinds of expensive retrofits. Basically, it means that coal plants would have to retire once they reach 45 years.

Moderator: I'll just add a quick correction as the moderator. It's actually 50 years now. They did extend it in the final legislation from 45 to 50.

Question: Notable sort of in its absence was, I think, any discussion on the demand side. And I was wondering, what sort of activity do you see there on either people just responding to price or anything else?

Speaker 1: Yeah, one of our recommendations is also to bolster the demand side a bit more, but you know, you can't really do this at a $1,000 price cap. There are two programs--this LSSI program that's similar to what you've got in Texas, but in this case for transmission constraints. You can curtail load. There is some price responsive demand. There are at least several hundred megawatts in the market that the ISO sees as dropping off as soon as prices hit $300 a megawatt hour. But we did a survey on demand response a couple of years ago, and there's a lot more. You have people in the market doing deals with sort of cooling houses or ice rinks, where they would switch off the cooling when prices are really high and so on. But the reality is there's not a lot of demand response in this market, compared to the US markets. Of course it's hard in an energy-only market. But it's particularly hard in a market where the price cap is $1,000, because even the residential demand response or a lot of the commercial demand response wouldn't bother unless they could see a lot higher prices, or aggregators who find it hard to make it work for their customers if they can't point to the possibility of much higher prices. And then, of course, most of the load, just like in the US, is contracted forward a little bit, so not a small portion of the load is actually paying the hours prices. All the residential load, which is a small portion of the market, but all the residential load is on like a four month forward contract. So there is not a lot of demand response, but we have identified a number of areas where demand response could be encouraged, and that that would be good for the market design.

Speaker 2.

So my presentation's going to be nice, because Speaker 1 has taken us through some of the Alberta stuff. So I'll try and leave you with a bit of a sense of why I think it works, and a few of the interesting features. And then at the end of the presentation, I've actually got some questions for all you guys about issues that are in our market, and that maybe are in your markets, and maybe aren't.

Given that our market is somewhat different in terms of its structure, it poses some fairly unique and interesting questions. So the first real observation is, we're pretty fortunate in Alberta, and we don't have a "making markets work" problem. We actually have a "letting markets work" philosophy. So is that even possible in your particular jurisdiction? Will you allow markets to work like they do in many other sectors in the economy, or are there political or cultural or just other expectations present that mean you can't have what you would normally have in any other industry? That is, people profit maximizing and trying to make as much money as they can. If you don't allow that, and if you layer on things like reserve margin targets, you're really taking away a lot of what markets would provide you.

So making markets work is probably a really good question in almost every other part of North America. I think the question is, for Alberta, why are we able to let the market just work? Well, you can think of energy-only markets really as just like many other markets. We have a capital intensive industry. We need to allow fixed costs to be recovered in order to attract new investment. We don't have a capacity market tacked on the side to ensure recovery. We have a bit of revenue coming from operating reserves, as in everywhere else, but essentially we're relying on that energy price to fund our new investment. And our view of electricity market design is that really you're just solving this problem about ensuring fixed cost recovery and trying to maximize efficiency gains over time.

So if you read a lot of the literature that the MSA (Market Surveillance Administrator) has put out over the years, it's increasingly focusing on efficiency measures. So we distinguish between static efficiency and dynamic efficiency. Static efficiency is real time dispatch efficiency, allocative efficiency, things like that. But the vision behind the Alberta market, and I think a lot of other markets when they first deregulated, was that somehow competition is a better way of driving dynamic efficiency. So it might be a better way of determining what the right reserve margin is. It might be a better way of determining when you build that next plant. You know, you can save an enormous amount of money by delaying a plant that's not needed. This is the problem with the traditional regulated system, where you could get plants being built. You could convince the regulator, and the regulator may not have all the information that he needs to make a very accurate decision, and you end up with a plant being built too early, and now you're paying for that, because it's rolled into the rate base, or however you recover your regulated plants. Competitive markets really offer that potential to reward smart people for building things at the right time. The reward smart people for not building things too early. And they reward smart people for not building things too late.

Now a lot of other electricity markets have kind of taken some of that away, because you've got a reserve margin. You have a target reserve margin, and there isn't much prospect of the government or the authorities of the day allowing the reserve margin to go down. They're going to intervene. And that's a big question, then. How exactly are they going to intervene? When are they going to intervene? So really the Alberta market is going back to a sort of fundamental economic concept that competition actually works really well, unless you've got a market failure that you can identify, and maybe we do, maybe we don't. I don't think we do in Alberta. But you only really get the benefits of competition in its full sense if you can let the market work. If not, I agree that the title of this panel is a really sensible one. Once you've constrained competition, and you won't allow it to work freely, then you've got a problem of trying to get something good out of competition or markets.

So this reserve margin history slide is very similar to one Speaker 1 just showed you. And the real purpose of showing this is to show how the reserve margin sort of goes right through the middle in the range of 15-20%. There is no target in Alberta. So we've just let the market run, and we get between 15 and 20%. The really interesting part of this graph is the line that shows you the view in May of 2008. And it said by about today, in 2013, we would have a negative 10% reserve margin based on what was under construction. Does that worry if you're an energy-only market? It might, but it shouldn't.

No one tells you what they're going to build five years from now in a competitive market. Why would I tell my competitors what I'm going to build five years from now?

We're quite fortunate now in Alberta. Most of our capacity here is being added as natural gas. It takes two to 2 ½ years to get through the permitting and construction cycle if you do it properly. So you're never going to see a reserve margin that looks very attractive five years from now. So if you like energy-only markets, you can for sure monitor this thing and go, "Oh, that looks kind of like it's going down in 2013, or again in 2018 it's going down quite low." Will it happen? No. Will you get in an energy market that kind of warm and fuzzy feeling that we've definitely got enough capacity? No, because people don't tell you years and years in advance.

There's no missing money. Here are statistics showing you the heat rates. Heat rates have been very good as natural gas prices have declined. So this gets a big to a point Speaker 1 was making about how we quite often have price spikes within any given time. So that's good. We've done some analysis of what kind of capacity would be attracted to our market, and really as far as we can tell, you can't really look at average prices to tell where the capacity should be built. We're really looking at an attractive market right now for peaking plants, and that is to capture those high prices that occur. So we've actually done some different ways of looking at building plants by constructing a sort of a derivation of a price duration curve to show that a peaking plant can essentially choose how to offer in our market. You can choose when you would like to run by offering a marginal cost, rather than offering at our price cap. We can find a range of capacity factors that you could run a peaking plant at that would make it profitable. Our test is a little different, where we're doing an essentially a five year rolling window, so we try and look at forward market prices, rather than at current prices. And we try and look back at recent history to get a kind of a period of time to assess. You don't have to make money in every year, and you don't expect to make money in every year, but you need to be able to make money over a sort of a medium-term time period.

We did a large report last year, which is entitled *State of the Market Report 2012*, and it's quite a long report. It's about 80 pages, with about another 200 or 300 pages of supplementary papers, getting into some fairly detailed economic analysis, and also presenting something of the economic theory. So if you want to learn a bit more about why Alberta is how it is, why we permit economic withholding, and you don't get enough from today's session, it's all described at length in there. We set up a test for "effective competition." You may be familiar with "workable competition." We went with the phrase, "effective competition." "Workable competition," to, I think, normal people has a somewhat apologetic ring to it. It's sort of workable. It's just about OK. It's just about passable. Maybe it's sort of tolerable. That's not really what economists mean by workable competition. We just mean that we don't have perfect competition, but we're getting a lot better. There's no great definition of workable competition, either. So we ended up creating our own term, just to confuse people. But what we hope is that the term captures a sense that competition is effective.

How do we know competition is effective? So we measured static efficiency losses, including any losses that would be incurred from economic withholding, and we tried to assess dynamic efficiency gains. And our conclusion was that the dynamic efficiency gains that have come from the market over the last 12 or 13 years are likely to be significantly higher than the static efficiency losses that we're incurring. So this is a very economist-driven thing, but it's a very important thing. This is why we went down this route of deregulation in the first place. We wanted society to be better off over the long term. That doesn't mean it's better off every single year, but we want to get it to a better place.

And then we also included in that test for effective competition that prices are no higher than long-run marginal cost over the medium term. Long-run marginal cost is another great economist concept. Essentially, we don't want the prices in our market over a number of years, and our sort of formal test is five, to be higher than the long-run marginal cost, the cost of the next plant that we need. If it turns out that the prices are lower than the long-run marginal cost, as the agency responsible for monitoring the market, we're not worried if they're lower. We may be worried if the reliability margin shrinks, and adequacy is not looking good, but we would be concerned if our prices got above long run margin of cost. Well, why? Because there's now a profitable opportunity for entry. So if someone takes that profitable opportunity for entry, prices are constrained by competition, we're happy again. So the *State of the Market Report* sets that out in some detail.

I've got exactly the same picture about distribution of prices as Speaker 1, so we didn't collaborate. I put on here the average prices as well, die ERCOT in 2011, $42.44 and AESO, $76.22. So that's the difference. That's the, we don't have the missing money here. $76.22 in 2011, that's enough to build a peaking plant, particularly with the duration curve here. We've got high prices above $500, as Speaker 1 said, about 4% of the time. So what drives this?

We've mentioned the Market Surveillance Administration's Offer Behavior Enforcement Guidelines. As the enforcement agency, the Market Surveillance Administration doesn't have any power to make any roles. We don't have any power to change any rules. So we didn't change anything, per se, when we came out with these Offer Behavior Enforcement Guidelines. What we did was clarify for people what the rules actually were. So right from the beginning of the Alberta market, there's been a price floor at zero, a price cap at $999.99. It's been just like that, and people have been able to offer into the market pretty much wherever they chose. And what we saw, quite bizarrely, really, when you think back of it, is when the market first opened, people started offering at marginal cost, because they thought they should. Then they realized that wasn't actually profit maximizing. So they changed their behavior. What we ended up with in the sort of mid-2000s was a situation where a couple of market participants were actually doing what you would you think of, which is economically withholding, offering at higher prices, and some weren't. Some of our market participants felt constrained, and as the enforcement agency, it is necessary from time to time to investigate people. So I think some of them felt that because they'd been investigated, or we'd asked questions about why they were offering in such a way, they were constrained from doing so. So what we found out was that a variety of them had sort of self-imposed bid caps, where they would only offer up to $300, $400, $500 into the marketplace. So quite a bizarre thing. We had one market participant that wasn't doing that. But obviously, if everyone else is, it constrains his sort of optimal behavior. So the Offer Behavior Guidelines that we consulted on and then released in early 2011 really just make it clear that if you're exercising unilateral market power (you're acting just on your own, you're not acting in concert with anyone else) and you don't impede anyone else from acting, then you should try and profit maximize.

So while that is a very unusual standard in electricity markets, it's pretty much the standard of the rest of world, in terms of every other industry that we have. We don't expect people to hold back from trying to profit maximize, and in all those other markets, we expect competition to try and constrain the outcomes, not regulators or regulations. So we end up with quite a different context. It does mean that we have more high prices than we would otherwise have, if we constrained things down. And does it mean that these prices are completely crazy? No, it doesn't. And this is the scatter plot of prices I've got up in front of you now. So the supply cushion, the axis along the bottom, really is just the number of undispatched megawatts in our system. So typically--maybe 75% of the time, something like that--we've got at least 750 megawatts. You can't really get a sense of that from the scatter plot, because those scatter points are so densely clustered. So most of the time we're above a supply cushion of 750 megawatts. So we've got quite a lot of surplus in our relatively small market. And so 25% of the time we're below 750. And what you see is that as we start to get towards that running out of capacity, but usually well in advance, we see offer behavior starting to influence prices, not in every single hour, because obviously if you're asking people to profit maximize, a generator who has market power under normal circumstances, but there's a whole bunch of units out, probably doesn't have market power in that particular hour, so they can't exercise it. That generator may have chosen to sell forward that particular month, or that particular day, so that they have no incentive on that particular day. But you do see what I think is quite a predictable pattern that whenever we get towards those situations, not where we're running out, or we've run out, where we would hit, by definition, hit the cap, but where we're close to running out, you get a range of prices, and in some cases high prices.

Why is that the case? Well, we know from how we look at market power in electricity markets coming out of some of the stuff that California did nearly ten years ago now on pivotal supplier metrics, or residual supply tests, that kind of stuff, we know that market power increases as scarcity increases. Your ability to influence the spot price is obviously greater when we're close to running out of capacity. No one has any ability in our market to influence the price when we've got 2,000, 3,000 megawatts, probably even 1,500 megawatts of undispatched capacity. That's why our scatter plot there is a very tight cluster at a very $50 or less price range. So this is the primary reason why we're happy that competition is actually working quite well. I suspect there'll be more questions about that. So I won't give you all the answers now.

So then I had a slide really trying to demonstrate, well, is there any reason that Alberta is different?

- We're relatively small, so our large units here are 450 megawatts. So losing a handful of those can cause a scarcity event. That's a difference.

- The growth rate's about 3% over the next 20 years, and it's been high.

- Cogeneration is a really interesting factor in the Alberta market. It's quite easy to build cogeneration here, because you have a customer up in the oil sands or tar sands, if you prefer, that will happily purchase power from you for 30 years, or happily build the power plant for itself, and then excess capacity ends up on the grid. So building cogeneration here is not a problem for the market, and that's where a lot of the growth is coming from.

- Speaker 1 talked about high load factor and interconnections and transmission policy. I've talked a bit about economic withholding already.

- We do have power purchase arrangements that exist. None of these mitigate offer behavior. But they do influence the way that people operate in our market. So that's an important factor. These were sort of virtual divestiture arrangements that moved us from our regulated three utility market to the market that we have now. The last of those expires in 2020. So only in

2020 are we free of these regulatory constructs. They influence behavior, but they don't directly influence offer behavior.

- We have a lower price cap than other people, and relative policy stability.

And then I threw out some questions at the end:

- Will Alberta drive further consolidation? Or are there forces at work to reduce market power? We actually think the latter. What happens if you exercise market power in our market is, you do that by economically withholding your units, not running them. So one of the metrics that we measure is, for a guy that just runs his capacity, and doesn't economically withhold, does he get a better return per unit of capital or per megawatt of capacity than the guy that economically withholds? And the answer to that is, yes, he does. So this is one of the forces in energy-only markets that's supposed to drive people to recognize, "Well, if other people are economically withholding, I could actually build a small unit, or a reasonable sized unit, in Alberta and just run it flat out. They can carry on economic withhold to their hearts content, keeping price nice and high, and I get a fantastic return."

- Will resource adequacy continue to be a non-issue? I think Speaker 1 said that yes it will be a non-issue, and I would agree.

- A price cap of Value of Lost Load in energy-only markets is one of these things that you see in some textbooks, and certainly that's the way they've gone in Australia. If you have market power like we do in Alberta, where should you set the price cap, is a really interesting question. Do you need it to be at VOLL? Well, evidently not, because we're getting resource adequacy here. We don't have missing money. Perhaps, in fact, your price cap really needs to be inversely proportional to the market power that you have. If you have more market power, you may not even need as high a price cap as we have right now. If you had less market power, you'd probably need a higher price cap. So there's a good question for you.

- We don't have any automatic offer mitigation of any offer mitigation at all. One of the quirks of offer mitigation is, you don't really have to worry about coordinated or consciously parallel conduct in spot markets if you tell people how to offer. If you let people offer freely, now we have to worry about the potential for coordinated and consciously parallel conduct. So that's an interesting question, too. I'll just leave that floating out there.

And then just to leave you with the final thought, which is really the first one, in most sectors of the economy where we rely on profit maximizing competitors to determine how much to invest and how to compete, that drives down prices to benefit consumers. We don't typically do that in electricity markets. We don't completely do that in Alberta, but we're a lot closer than most.

Question: Thank you for your presentation. One of the things you listed in one of your slides was that the recovery of cost comes from both the energy only price and the operating reserve pricing. Can you talk a little bit about how you came to the operating reserve pricing piece of that and how important that is in the equation of solving the missing money?

Speaker 2: So interestingly, when we did the *State of the Market Report*, we were trying to keep it doable within a reasonable timeframe. So we didn't actually look at the money at all that you get from operating reserves. It's fairly substantial in Alberta, given the size, and we're looking at sort of $330-340 million a year. The design of operating reserves in Alberta is fairly rudimentary, and it's one of the things that is causing us some concern. Simply, the operating reserves trade day ahead in their index to pool prices.

Speaker 1: But just to add there, because we did look at this, it doesn't add that much to the missing money. I mean, it's a small portion of the missing money. A combined cycle unit might get on average maybe $20-30 a KW year from the reserve market, but you have to understand that if people sell reserves, they're forgoing the opportunity to make profit in the energy market. So just because you make $30 a KW year in the operating reserve market, that might mean you would have only made $15 in the energy market. So incrementally, it's going to be an even smaller portion.

Speaker 2: Yes, I think that from an economist's point of view, the test should be the same that we've applied to the energy market. We would think the operating reserve market is overheated if you could build, say, a single cycle peaking plant, a small one, and just offer operating reserves, and at the market clearing price, if that meant that you got an excessive rate of return, or you're above that long run marginal cost for a fairly persistent period. We'd conclude that the market was problematic. Now, doing that calculation is a little difficult, but we're working on it.

Question: What's the structure of the retail market? Is it fully deregulated as well? And are most of the wholesale suppliers also retail providers?

Speaker 2: There's one large city utility in Calgary that's a major provider of competitive and regulated retail services. So it's a bit of a hybrid system. There is full retail competition in theory. Everyone can choose to go under a competitive retail contract. In truth, people just aren't that interested. Because we have this relatively high load factor, and we don't have high peak demand. There's no real case here for smart meters or innovative products like that. And that's kind of natural. I don't see that as an unnatural thing. I think smart meters make an enormous amount of sense if you've got a load shape like you have in ERCOT and an enormous potential. Here we don't have that. So our market is maybe, on residential, 65% to 75% regulated. Now, those regulated rate providers are required to go out into the forward market and purchase or price energy to determine the prices for those regulated products. This hasn't proved very popular with residential customers, and the government is looking at how to modify that. It's fairly, you know, if you rate it against other places in North America, Alberta usually comes up number two in the retail competition rankings, just behind Texas.

Question: I really enjoyed your presentation. Thank you. I may have misunderstood something maybe you can clarify. You were talking about how when you monitor price outcomes, you see outcomes below low marginal cost levels, and that doesn't trouble you. But if they're above, you start to get worried. But since we have to average that level, aren't you going to have to be above some of the time?

Speaker 2: Oh, yes, no, no, we're only concerned if we're above for a sustained period of time. So if you're a pure economist, you only care about the long term. Unfortunately, we are in electricity, so if over the medium term our prices were above long run marginal cost, we wouldn't be able to sustain it politically. So we need to recognize that. So we're not looking at an hour above long run marginal cost. We're not looking at a year above long run marginal cost. We're really looking at five years above long run marginal cost.

Question: Do you ever have any buyer market power concerns that might keep prices below the long run marginal cost?

Speaker 2: Coming back to the question about retail, residential retail does purchase a fairly significant amount. It's about 1,000 megawatts in total. But because of the way the regulations are structured here, they're forced to purchase in a particular way. So there's not a ton of buyer market power. You have to remember, as well, that Alberta's a little different. A lot of the plants are cogeneration. So, you know, you may have one operator with 900 megawatts of generation, who is consuming the majority of that themselves. So in a system that peaks at 11,000, those cogeneration participants make up 3-3 ½ thousand megawatts. So they're self-supplying. They're either taking from the grid or putting to the grid, depending on their particular circumstances.

Speaker 3.

Thank you. I really enjoyed the Alberta presentation. That's really quite fascinating, and, as an economist, I found it to be a bit of a head scratcher.

California is very different, and I appreciate having the opportunity to kind of give you a broad brush overview of what's going on in California. There's a lot happening in California. And there's a lot happening in the energy environmental policy space. And when you think about the future of energy markets, I think California provides an interesting contrast to Alberta in terms of the complexity and the multitude of very prescriptive policy objectives that California policymakers are pursuing. And it does beg the question of, how does an energy market need to be designed to help facilitate in the most cost effective manner achieving these policy objectives? So I'll try to highlight that in my presentation.

It is kind of a timely opportunity to have this discussion, because California is at a crossroads with its energy market design, both in terms of the long term, how do we ensure not just capacity, but I use a term in my presentation called "capabilities," because as I get into some of the complexities we're dealing with, we really are talking about making sure that at the end of the day we have the right mix of resources with the right operational capabilities available on the system. And then the question is, how do you optimally utilize those capabilities in your market to reliably operate the grid and meet your needs?

This slide just gives you an overview of what the California market looks like today. I would call it really a hybrid market structure. So in the operational year, you have the ISO's markets. These are FERC jurisdictional markets, and they include day-ahead and real-time spot markets, and energy and ancillary services.

We made a concerted effort as we kind of rebuilt the California market after the energy crisis to make sure we addressed prospectively the resource adequacy requirements of the state. And the California Public Utilities Commission took that on in establishing a year-ahead resource adequacy framework, which ensures we have sufficient capacity on the system a year in advance of the operating year, for meeting both system and local needs.

And then there is also the long term procurement framework that the Public Utilities Commission has, and that's really looking at new generation build. So it's essentially taking the existing fleet that we have today, any retirements or additions we know about in the intervening years, and then asking the question, "Looking out at year ten and beyond, do we see issues, shortages at both a system or local level, that we need to address by authorizing utilities to engage in new generation procurement?"

The intervening years is where it gets a little murky. So I've highlighted in here years two through five, where there is a significant amount of forward hedging that the PUC jurisdictional load serving entities do, and they do have an obligation to hedge to protect retail rates. But there isn't a whole lot of transparency around what actually is getting procured and what costs are associated with that procurement.

I know that with our market participants this has been an area of contention--this is a really nontransparent murky area that in the long run isn't really efficient for facilitating proper market signals.

How well has this construct worked? Well, if you look at the amount of new generation that's been added to the California market since the crisis, it's quite impressive. I haven't tallied up the total, but in the chart on the left there, the blue columns show you the amount of new generation capacity added to the system. The red, below, shows the retirements, and the yellow lines the net. So cumulatively, since the crisis, on net, we've added roughly around 15,000 megawatts. And if you look at our operating reserve margins, which you see on the graph on the right, you can see, particularly in the last five years, that we've had operating reserve margins above 20%. (This is different than planning reserves. For the operating reserve margin, you're actually subtracting out your anticipated forced outages over the peak, and even with those expected outages, you have operating reserve margins well in excess of 20%.)

So a lot of investment has occurred in California. How are the ISO spot markets doing in sending signals for new investment? Well, it's no secret. Not very well. What this graph shows is the net revenues that a hypothetical combined cycle unit could earn in the California market. The blue is for Northern California, and the green for South. And then the orange line shows the revenues that would be required to cover the long term capital cost of new investment in a combined cycle unit. So, you know, this is often referred to as the "missing money." But I would ask, if you have in excess of 20% operating reserve margins in your market, should your spot market really be sending signals to incentivize new investment? Certainly not in the current year. If you look out in future years, that might be a different thing, but I think you can legitimately debate whether this is a missing money problem, or the right signal given the amount of investment we've had to date.

So to switch gears a little bit, and talk about looking forward, what are the big policy and environmental drivers in California? We have a lot of them. We have a goal of reducing greenhouse gas emissions to 1990 levels by 2020. We have a very ambitious RPS goal of having 33% of retail load served by renewable generation by 2020. And I would just add, we're doing quite well, actually, at meeting that goal. We have a governor that's keen on seeing distributed generation proliferate and has a goal of 12,000 megawatts of distributed generation by 2020. And then, on the conventional generation side, our state water board has a ban on the use of once-through cooling for coastal power plants. And I'll have a slide that speaks to that. It's quite a significant energy policy. And then, of course, in some of the air basins in California, there are limitations on air emissions.

I won't get into all the details here, but the numbers for the impact of the once-through cooling requirement are quite staggering. The impact is predominantly on the gas fleet in California, which is the resources that are often on the margin, the dispatchable, flexible resources on the system. And we have roughly about 11,000 megawatts of gas generation that has yet to come in compliance with the once-through cooling regulations. And, effectively, to come into compliance for most of these units, it's going to mean basically tearing down their facility and building a brand new one. There aren't a lot of good options in terms of mitigating the once-through cooling. (I assume people are familiar with this. The issue of once-through cooling is, you take in ocean water to cool your facility, and then you release that water back into the ocean at a much warmer temperature than the ambient temperature. And so that creates environmental issues, as well as entrainment from the intake structures.) So realistically, to comply with these regulations, and the fact that most of these plants are 40 to 50 years old anyway, is going to mean tearing them down and building new ones. And then we have roughly about 2,500 megawatts of generation that have already come into compliance.

And then for the nuclear units, the big change since I produced these slides, I'm sure many of you saw, is that the San Onofre nuclear generation station, about 2,400 megawatts of generation in Southern California, announced last week that it's permanently shutting down the facility. So that is a big hit in terms of meeting some of the local needs in the L.A. area. So what this map to the right highlights is, the yellow areas are local areas where we need local generation, because they're transmission constrained, and a lot of those coastal power plants that are going to be needing to comply with the once-through cooling are in these constrained areas, most notably the L.A. basin. We've also had announced last week proposed legislation to actually move to a 51% RPS goal by 2030. So that legislation's going to carry into next year, but certainly that's a big deal. We'll see where it goes, but I can tell you there's a lot of interest in advancing the RPS goals even higher in California.

Getting back to the OTC (once-through cooling) units, just what this chart shows is that if all those OTC units go away, California is going to be losing a huge chunk of flexible capacity on the system. And when you couple that with the influx of intermittent resources, like wind and solar, you have to ask the question whether at the end of the day, we are going to have the right mix, and sufficient capabilities on the system to manage some of the operational challenges that the renewable fleet presents? This chart just highlights the dynamics from a capacity standpoint. So you see the timeline from 2011 to 2020. On the top part of that chart, you see the wind and solar resources being added to the system, where by 2020 we'll have close to 15,000 megawatts of renewables on the system. And then below you see the loss of the once-through cooling units, where you almost have a comparable amount of flexible dispatchable generation falling off the system. The studies we've done looking at the need to replace a portion of that generation, these studies are being updated, but at least on this last study we did, we indicated a need for about 4,600 megawatts of flexible ramping capacity by 2020. And I'll talk more about that in the presentation.

I'll go through these slides relatively quickly, but they really highlight the operational challenge in terms of the net effect of having large amounts of wind and solar placed on the system. We spent a lot of time studying this, because again, we're very concerned about our ability to manage it. And what this looks at is a simulation, looking out to a winter month in 2020, where you look at the wind profile--nothing too dramatic there. It kind of oscillates a little through the day. For solar, you can see significant solar output during the middle part of the day, getting up close to 10,000 megawatts. But if you contrast that with the gross load profile, you see that the peak of the solar is not coincidental with the system peak. So if you were to net out the wind and solar production from the gross peak load, you get this net-load profile line, which really highlights the operational rollercoaster that we'll be dealing with. So you can see here significant ramping requirements in the morning as that solar is coming up, and also the load's coming up. You have 8,000 megawatts ramping up, and then as the solar really accelerates up, you have more than is required to meet the load. So you have a need to ramp down during the morning hours as the solar is coming up on the system. Then you get into a trough. And then when you get into the evening, you have the load pull, where the load's coming up in the winter. People getting home, turning the lights on, turning the TVs on, etc. And then you have the solar dropping off like a rock. So there's a huge evening ramp that we have to manage. And what's striking is not just the magnitude of that ramp, but it's the speed at which it happens. We're talking about 13,500 megawatts in two hours. As one operator put it, that's like winding a lot of generation up on rubber bands and just letting it fly when you know you're turning that corner, because you're going to be chasing that ramp and hoping you have enough capacity to keep up with it. So it's very significant and very concerning for us. We're taking steps to make sure we can address this, but I don't want to underplay the significance of this challenge.

So that net load chart that you saw on the previous slide is shown here for different operating years. We call this, by the way, the duck chart. I think it's self-evident (that it looks like a duck). In this year and next year, you see that during the middle part of the day, we don't see that big of a drop, because we don't have enough solar on the system. But as we project out into future years, you see that trough starting to develop as early as 2015.

So this raises two operational issues. One is the ramping requirement that I mentioned. That's the steep portion of the chart you see in hours 16 through 20. This net load projection also raises an over-generation issue, as you have all that solar on the system, coupled with resources you're going to need to have on, must-take resources, resources operating at minimum load. We are also concerned in that middle part of the day of having over-generation issues.

So to sum up, the challenge we see in California is that our system needs are going to be changing dramatically over the next decade. And it really gets to not just the local needs with the once-through cooling retirements, but the need for flexible capacity to manage those big ramps that we see, to manage load following-- with wind and solar, even within an hour you're going to have variation due to cloud cover and variations in wind. So you need resources that can manage those within-hour variations. And then, of course, you need sufficient regulation on the system to kind of clean up with whatever ultimately you're dealing with in real time.

So you have these dramatically changing needs that are really being driven by dramatic changes in the resource mix. So this raises really two key challenges for us. How do we ensure we identify and secure the resource capabilities we know we're going to need in future years, and then how do we ensure we optimally utilize and price those resource capabilities in the ISO market? And Speaker 2, in seeing those two challenges, would probably argue that if you get the second one right, the first one will take care of itself. I can tell you we're not convinced. The magnitude and pace at which things are changing in the California system are so great, so quick, that to simply rely on the market and hope it all works out is just not a tenable option for us. So I'll offer that as a provocative statement to stimulate some discussion later.

So how do we deal with this if we think we need to get the right resources identified ahead of time? Does the current construct provide for that? Does the bilateral framework we have with the state regulatory authorities provide for that? Our view is, it needs to change. And there's considerable debate in California about how it needs to change. One option, which I highlight in the red box, is that there's a lot of interest among our market participants in establishing a multiyear-ahead capabilities market where we would be procuring in the three to five year timeframe, most likely a three-year timeframe, the capabilities we need in terms of flexible capacity, locational capacity, and system capacity, and this market could be complementary to the PUC's bilateral procurement framework. But this is very controversial, and it raises significant jurisdictional concerns with the Public Utilities Commission relative to having FERC extend its jurisdiction into multiyear ahead procurement issues. There are many who would like to see a hard line drawn between year zero and years one through ten, where FERC jurisdiction is in year zero, but beyond that, it's the state's role. And you see that debate certainly playing out in the eastern ISO and RTOs as well.

Alternatively, we could take a more gradual or measured approach of just modifying the state's procurement framework and introduce a multiyear-ahead RA (resource adequacy) requirement. So instead of just having a year-ahead requirement for system and local capacity, we could transition to a multiyear-ahead RA requirement that includes flexible capacity, and then have some sort of a backstop procurement for the ISO, where if the procurement coming out of that state process falls short of the requirements, the ISO could step in. And then the question is, do we step in only in year one? Or would we consider stepping in during years two and three? So this debate's ongoing, unresolved, and we'll see how it ultimately plays out.

Let me switch gears a little bit to how the ISO's market has been evolving over the years. We did implement an LMP market in the spring of 2009. It has all the usual bells and whistles of the eastern ISO markets. And we do co-optimize energy and ancillary services (regulation, spin, and non-spin). And we've been implementing many enhancements over the years. I'm not showing all of them, but I've listed ones which have really been targeted towards trying to use the market to procure the capabilities we need and to also price the capabilities we need. So part of it is within the market itself, trying to optimize and price the attributes we need operationally. And then also broadening the scope of resources we can use through developing a more regional approach to meeting our balancing needs. So the Energy Imbalance market, which some of you may have heard about, is something that we think will ultimately help in meeting our challenges.

Let me talk about just a few market enhancements in the spot market. The first one is one we actually have had in place over a year now, and it's called the Flexible Ramping Constraint. That's in our real-time market. So like most LMP security-constrained economic dispatch markets, our market optimization is forward looking, even in real time, looking ahead over many intervals of what the projected needs are of the system. But, of course, all of those projected needs have an inherent forecast uncertainty. So that when you get to that actual next operating interval, you may have generators deviating from what the optimization assumed they were going to be doing. Your load may actually be higher than the optimization projected. So we've seen ourselves operationally caught short with not having enough ramping capability in real time, where we're not able to, in the five minute market, balance supply and demand, and when that happens, we get these penalty prices, so we get a lot of real-time price volatility. So you can essentially call this Flexible Ramping Constraint a cushion to account for the inherent uncertainty in the optimization, where rather than just securing enough for your target point, we're going to add a cushion on there of additional megawatts of flexible capacity. In this case it's just upward capacity that we want you to procure. And the optimization will make sure that there's enough head room in the dispatch to accommodate that.

And then the question is, do you need to price it? The optimization will automatically provide an opportunity cost. So if a resource is held down in the current interval because it wants to be used in future intervals, and there's a lost opportunity cost to that, there would be compensation for that. But if that Flexible Ramping Constraint's not binding, so there isn't an opportunity cost, should there be any compensation? This was debated with our market participants. It led to a settlement at FERC where it was agreed that there should be compensation in all hours for providing this service, even if the constraint's not binding, and I won't get into the compensation and administrative price right now, but we do have that in place. And in 2012, the revenue from this constraint was around $20 million, compared to about $35 million for spinning reserve.

We are also considering a flexible ramping product, which would be kind of the evolution from the constraint to actually having a capacity bid-based product, much like our ancillary services. And we'll be kicking off or reinvigorating a stakeholder initiative around that, and I can tell you there's a lot of debate about whether you should provide capacity compensation for this, or if, so long as you're compensating for lost opportunity cost, it's adequate. So we can get into that as well later.

In the interest of time, I won't dwell on this, but we've made a lot of improvements to our regulation market. Regulation Energy Management allows resources that can't provide regulation energy for an entire hour to still participate in this market. So resources like batteries see this as a very attractive market feature.

Pay for Performance Regulation is another improvement--all ISOs/RTOs had to implement that. Essentially, instead of just having a capacity payment or providing regulation service, you're also given a payment for mileage, which recognizes that if you get used for providing regulation, you should be compensated for that in addition to your capacity payment. We just implemented that last week, or June 1.

Finally, moving to how we are trying to address these issues by broadening our regional dispatch, we see FERC Order 764 as a great opportunity for that. That order requires transmission providers to offer 15-minute scheduling on the interties, as well as providing variable energy resources to provide meteorological and forced outage data. We viewed this as an opportunity to revamp our real-time market, and our compliance proposal for this would actually implement a full 15-minute real-time market. So we'd have a three settlement system in our market, a day ahead, 15-minute market, and a five minute market. And in addition to providing opportunities for interties, and to resources outside our balancing area to help in meeting our balancing requirements and vice versa, we think it's a great improvement for renewable resources and forecasting, because we can get more accurate, closer to the operating interval, forecast information for variable energy resources. So we're planning to implement that in the spring of 2014.

Those of you in the West may have heard about the EIM, energy imbalance market. This really got kicked off as a joint venture between the ISO and PacifiCorp, where we'll be operating a real-time imbalance market for the PacifiCorp balancing area, which is shown on the right in yellow. So effectively, we'll be, in real time, co-optimizing the imbalance needs between PacifiCorp and ourselves, obviously recognizing the transmission limitations between us, on both a 15-minute and five minute basis. And the design details around that are subject to an ongoing stakeholder process right now. Some of the issues have to do with what sort of day ahead scheduling and system modeling you have in place, and if there are any uplift costs between the 15-minute and five minute market, who pays for that. Another issue, of course, the big one, is greenhouse gas emissions. California has a cap and trade market where if you sell into California, you have to demonstrate you've provided greenhouse allowances for that. So how you manage that in the context of an EIM is a bit complicated.

So to wrap up, what I've tried to share with you is how the California spot market design itself is evolving over time. If I had to summarize, I'd say it's becoming increasingly sophisticated. I think California came from kind of the bottom of the heap in terms of market sophistication to, I think, on the leading edge, or maybe bleeding edge, of sophistication and optimization. There are other areas I haven't touched on where we really are kind of pushing the envelope. We are moving towards defining and pricing needed resource capabilities in the market. And, of course, we are trying to remove barriers to broader participation, particularly with clean technologies, storage, and demand response. We're very interested in getting that more engaged in our market.

And we're also working on then making sure we have the right mix of resources, evolving our multiyear ahead procurement framework, and I shared with your some of the debates there around leaving it as a state regulated process, versus taking a more market-based approach to procuring those capabilities. So that debate's very active in California. And I think we'll just have to stay tuned to see how it all plays out. So that concludes my presentation.

Speaker 3.

Good morning. Both Speaker 1 and Speaker 2 showed the scarcity intervals that we ERCOT had in 2011. There were about 27 ½ hours that were at the cap, with a roughly a 14% planning margin, and that was due to the extreme heat that we had that year. And then in 2012, we had only an hour and a half at the cap. And that was due to the weather not being quite as hot. So weather in Texas certainly has a big effect on the prices, with the difference being about $55/kW-yr in the for the year average 2011 to around $30/kWyr in 2012.

A little bit about ERCOT market: like Alberta, we are an energy-only market. We do have a day-ahead market in which we co optimize energy and ancillary services. And then in our real-time market, we dispatch generation resources every five minutes, and we calculate LMPs at the node. And we have roughly 550 15-minute settlement points that we use in our market. We run a Congestion Revenue Rights (CRR) auction, which our participants are able to use to hedge on a monthly basis, and there are six month rolling auctions that buy and sell instruments out to two years. We just implemented moving away from an annual CRR auction.

Our planning reserve margin is based on a one-in-ten year Loss of Load Expectation study. Our reserve margin target is currently 13.75%. And we have redone that study, and the results of that study are being discussed in our stakeholder process as we speak. As you will see, weather, drives the results of that study quite dramatically.

And with any market, the question is, is there enough revenue in the market to support your desired reserve margin? Currently we measure that with what we call Peaker Net Margin. This is an index that indicates the amount of revenue that a theoretical peaking unit would make if it were online every hour. Our current forecast for reserves indicate that we will be below the 13.75% reserve margin starting in 2015. We worked with the Brattle Group last year to perform some studies based on the expected reserve margins under the existing market design and where we were expecting to go with the offer caps. And what we found is that with the $3,000 offer cap that was in place in 2011, we could expect to average around 6.1% reserve margins. That's the reserve margin level that it was expected would yield enough revenue to support the cost of new entry, which they estimated to be around $105,000 a megawatt year. And looking at a $9,000 offer cap, the expectation was an 8% reserve margin on average. Obviously this has been a big focus in Texas.

This next graph will show you the expected reserve margin. The very top line is the forecasted load, plus the 13.75% reserve target. And what you see is that beginning in 2015, the resource capacity that we have in Texas is falling below that target number, and you can see how it's trending out through 2023.

So we made a number of recent changes to improve the scarcity pricing mechanisms and thus improve the incentives to build generation and send the proper price signals to attract investment, in order to stay at our target reserve margin. Starting this year, in June we raised the offer caps to $5,000. That's from the $4,500 that we raised it to in August of 2012. Next June we're going to $7,000 a megawatt hour, and then in 2015, we're going to $9,000. We also currently have in place offer caps. So any resources providing responsive reserve service, which is 2,800 megawatts of contingency reserves that we carry on the system, they're required to offer in their energy at the offer cap. And then we have 30 minute supplemental reserves called non-spin, that's required to offer no less than $120 for online, non-spin and no less than $180 for offline non-spin. And these offer floors are intended to provide proper signals and to mitigate against price reversals when the operator has to take actions in order to protect the reliability of the system. We didn't want to have a situation where deploying operating reserves by the system operator would lead to price suppression action and not send the right signal to the market. We'd rather the market fix the scarcity condition rather than relying on the operating reserves.

So what is the proper planning reserve margin? How we weight 2011 matters. 2011 was one of the hottest summers on record in 50 or 100 years. So it was very, very extreme. And if you put into the planning model a weighting of 1%, you would get a one in ten year loss of load expectation of 16.1%. If you weighted 2011 5%, you would get a loss of load expectation of 18.9%. Now, actually, in 2011, we did not shed firm load. We had a planning reserve margin of 14% going into the year. We got very, very close, and we relied on our emergency reserve load service to prevent the need to firm load shed in August of that year. But you can definitely see the impacts of weather in Texas on the planning reserve margin.

We don't do an economic evaluation. We do the one in ten years evaluation. This slide shows the difference in the results that you might get from using a one in ten year basis versus doing an economic analysis. One of the things to note on this slide is that you can increase the reserve margin over what is the economically risk-neutral point, and mitigate the risk quite a bit for not that much cost difference, from where you see the economic neutral point at 12% going up to a little bit higher than that.

The results of the study that Brattle did for us indicates that there is missing money at our 13.75% reserve margin target. Going to $9,000, the expectation is that $9,000 would only support an 8% reserve margin, meeting the cost of new entry requirements of $105,000. And there are obviously a number of reasons for that: low gas prices, heat rates are relatively the same in ERCOT for combined cycle units, and you don't get a lot of scarcity intervals when you get above 8%.

We've been working with Dr. Hogan recently on a new proposal. This proposal came about as a result of GDF Suez working with Dr. Hogan to file a paper based on real time co-optimization and using loss of load probability and the value of lost load in the analysis to calculate the value of the reserves. So when you get to the situation where you cannot provide for the demand and meet all your ancillary service requirements, how should those reserves be priced? And we've been working with Dr. Hogan to determine whether there are alternatives that can be done much quicker than real time co-optimization, which could take a couple of years to implement, given the involvement with settlements, the clearing engine, and different aspects of that implementation. So the question we've been working through is whether there is a way to approximate or create a proxy for real time co-optimization that we can do in a quicker time frame.

As I said earlier, 2011 was a very, very extreme hot year for us. It yielded 27 ½ hours in which we were at the offer cap, and when you look at the revenue that we got from that year, the Peaker Net Margin was roughly $125,000 a megawatt year. And that's adequate revenue to support the cost of new entry. And the planning reserve margin that year was roughly 14% going into the year. With relatively the same planning reserve margin in 2012, what we found is only an hour and a half of scarcity intervals at the cap, and the Peaker Net Margin that year was $33,952, not enough to support the target of 13.75%.

So we've been looking at what would be the effect if we implemented this Operating Reserve Demand Curve in our system. And looking at 2011 and 2012, we used the actual dispatch and actual clearing that was observed in those years, and applied the Operating Reserve Demand Curve to get an estimate of what kind of revenue you would get under that approach. And I'm going to show you the results of that in the next couple of slides.

The way it works is, you take the operating reserves that are left. You do a historical analysis using the planning reserve margin that you had the hour ahead, compared to the actual reserve margin that you realize after the hour is over with, and you use that error analysis to create a standard deviation and an average error that is used to calculate a loss of load probability. Now, it's really not a loss of load probability in the sense that you're expecting the reserves to go to zero. We're actually running that analysis with different minimum contingency levels, and the loss of load probability is based upon what is the probability you're going to fall below the 1375 MW minimum contingency threshold or the 1750 MW minimum contingency threshold, or a 2,300 MW minimum contingency threshold. (Those minimum contingency thresholds were based upon important numbers in this system: 2,300 MW is where we go to Energy Emergency Alert Level 1, 1750 MW is the level at which we go into Energy Emergency Alert Level 2, and 1375 MW is our largest generator in ERCOT.)

So depending on which one of those thresholds we choose, the amount of additional revenue that we saw from the backcast varies quite a bit. For the 2,300 megawatt contingency amount in 2011, the revenue would have been close to $400,000, and for 2012, it would have been $99,568. For 1750 MW, it would have been $32,000 in 2012, and $14,000 for the 1375 MW contingency level in 2012 as well.

Now, for comparison, if we just raised the system wide offer cap, going from 2012 with $3,000-4,500 system wide offer cap, to a $9,000 system wide offer cap, and if that was the only thing we did, how much additional revenue would have been realized by the system, everything being equal? And we found that in 2012, that was $8,800 and in 2011, that was $170,000 additional revenue.

What would the Operating Reserve Demand Curve approach do the average energy price? As I said earlier, the average energy price in 2011 was roughly $53/MWh. It would have added an additional $70 to that price in 2011 on a weighted average with the 2,300 MW contingency, and it would add an additional $26 with 1750 MW, and an additional $15 with 1375 MW.

Now, also with this type of approach, one of the things that you could do (we've been talking with Dr. Hogan about this as well) is that you could price value of lost load at one contingency level, and then have a different price for out of market actions that you begin to take as you get into emergency conditions. And those prices could be the same, or they could be different, depending in which direction we wanted to go in the market. And that would make a difference in the pricing outcomes. So one of the things that we found is, if you use the operating reserves, which have value, and you use that as a basis to adjust your energy price as a proxy for real time co-optimization, it would have a pretty dramatic impact on the revenue and the energy prices, obviously depending on which level of reserves and the value of lost load that you use. And looking at the backcast, with the higher numbers, it does suggest that it would support a 13.75% reserve margin.

However, there are some differences here that are hard to predict, and that is the behavior aspect. Obviously there will be a behavior difference as the prices change. And that behavior is difficult to predict. We are working with Brattle to try to do a future-type analysis similar to what they did for us with the existing offer caps, and what was done with the floors that we currently have in place. The floors that we currently have in place are intended, like I said, to avoid price reversals, and also to be an approximation of what those reserves are worth as you get into your operating reserves and reserves begin to get tight on the system. We're still in the middle of evaluating this proposal, and it is something that will be discussed and debated over the next couple of months.

General Discussion.

Question 1: This is for Speaker 1. The question goes to your slide about the California energy and environmental policy drivers. What are the prospects of further out of state REC sales from California in the future? In other words, is California meeting the 2020 target? And beyond that, what's the prospect of that 2030 legislation being proposed, and further out of state offset sales?

Speaker 3: Well, with respect to your first question about the prospects of renewable energy credits, RECs, contributing to meeting the 33% RPS, the legislation authorizing the 33% RPS did have limitations on contributions from out of state resources. And certainly the procurement the utilities have done has been very California-centric. There have been some imports, but I think it's safe to say the vast majority of renewable resources meeting that goal will be within California. The 51% legislation--or proposed legislation, I want to stress that this is a very new proposed legislation that will most likely play out over next year--I don't think that draft legislation got into the role that out of state resources can play, but I'm willing to bet that that would be front and center in the debate.

Question 2: Two clarifying questions for Speaker 3. The first one is, how far out does new generation have to report in per your rules? That is, when do they have to notify you that they're going to be bidding in? And also, I guess, when do they have to notify you that they're going to be leaving? And then the second one is, you have locational marginal pricing that you started in '09. How many areas do you have, and how do you determine that?

Speaker 3: Well, in terms of resources retiring, the amount of notice is really at the discretion of those resources. In our tariff, we have a 90 day notice requirement. We have the option of offering them a must-run contract, if we think they're critical and we need them. When we've done that in the past, they've taken us up on it. If they said, "No thank you…" we've never crossed that territory. That's uncharted territory. As far as notifying us that they're going to offer, once they're in our market, they offer on a day to day basis, so there's no problem there. In terms of the number of nodes we have under an LMP market, I think we have close to 3,400 nodes. So there is very detailed, granular pricing in the market.

Question 3: A couple of quick questions for Speaker 3 on California. I'm just trying to reconcile your slide three, which is your operating reserve margin, with the 5-10,000 megawatts of wind and solar. You have percentages on the one chart and megawatts on the other chart. So can you help me with slide three in terms of what percentage of your reserve margin is wind and solar, and the second question is, does that include external resources like interties in that calculation as well? And for interties, do they have the option for dispatchable right now? Or are they all firm?

Speaker 3: On slide three on the operating reserve margins, it does include renewables, not based on their nameplate capacity, but based on their qualifying capacity. This is all projecting on a summer peak. So, for example, the amount of wind capacity, I think we have close to 4,000 megawatts of wind on the system, but that's heavily discounted in terms of its contributions to the operating reserve margin. Solar would have a much stronger composition. But all told, I think, in renewables, we're looking at around 6,000-7,000 megawatts, current, that we have on the system. That would be discounted based on their actual availability to contribute to that operating reserve margin. Imports do contribute to it as well, and it's based on historical contributions. So if you wanted more details on that, we do have a report on our website that lays out all those details. But it consists of in state generation and imports based on their historical contributions over the peak. And I'm sorry, your second question was?

Questioner: So, just back to the first question, so you don't have the percentage then? So when you talk about 20-25 percentage, you can't convert that to wind? Is that maybe in the report? I should look there?

Speaker 3: I think you could tease that detail out of the report. I think there's enough information in there.

Questioner: I'll take a look. And the second question was just on whether interties have the opportunity for dispatchable offers, or whether they're all firm?

Speaker 3: Well, interties can participate in the ISO market either on a firm or non-firm basis, and we have an hourly market where we have fixed hourly intertie transactions. We also have some limited dynamic intertie capability where they can actually participate on a five minute basis. And then of course with FERC Order 7664, we'll be going to 15-minute granularity. So whether they're firm or non-firm, they can participate. And I can tell you, for some of our market participants, that is an issue of concern about the firm/non-firm level of participation in terms of, is it really an even playing field? So that's something we do hear about.

Question 4: I had a question regarding the Alberta market that was described. There were several conditions noted that describe the characteristics of the Alberta market that I think make the functioning of an energy-only market work. They included a high load factor in which there are quite a few hours in which one is relatively close to peak conditions for high prices. The high load factor also provides an opportunity for many hours of profitable operation and revenue for generators in the market. There's short lead time to entry--I heard 2 ½ years, which is a dream for us in California. And there's also, generally speaking, a lack of significant transmission constraints that cause problems with having really smaller markets in the entire market. All of these sort of contribute to the ability to have what sounds like some allowable level of market power exercise to raise prices, but not too much. It gives you the revenue sufficiency to encourage new generation. So all these things seem to combine to make this work.

Is that a fair characterization from your perspective? And if it is, then are there really any exportable lessons from this to other markets which don't benefit from those underlying conditions?

Speaker 2: That's a really good question. We don't know the necessary conditions for an energy-only market to work. We only know what we have in Alberta. I don't think all of those things are necessary. So the 2 ½ year build, versus a seven year build in California, it's definitely a good thing, but 2 ½ is the same in Texas, probably better in Texas than it is in Alberta, if anything. It's certainly cheaper in Texas to build new capacity, I think. So I don't think that one's there.

Where it becomes either political or the fear factor, if you're looking out sort of seven years, there might be more fear there that it won't come on in time. One thing is, it's really the compounding of competing objectives that I think kills a lot of other markets, or kills a lot of the possibilities--like in California, I think there are so many different objectives for the market, you couldn't rely on not intervening somewhere. And then once you've intervened somewhere, where do you stop? And it takes a brave person to know where to stop, and where you should go. Maybe it's just more and more intervention --even in Alberta, we suffer a little from having probably too many regulations that are too specific about what's supposed to happen. It would be better if we had fewer, so that our system operator here was freed up a little bit to consider a wider range of possibilities. We have the same issues brewing on environmental legislation, potentially. It could be that one part of the government, whether it's federal or provincial, ends up imposing environmental requirements or renewable portfolio standards. And if they get the way of doing it wrong, and it turns out not to be compatible with a market, or it distorts investment, the market won't survive something like that.

Now, we hope that after 13 years, there's enough understanding of how it works and why it works, at least within Alberta, that we're likely to get a compatible solution. So I can't really answer the question properly…

Speaker 1: Just a couple of quick things. I think the 2 ½ versus seven years difference is a greatly overstated difference, because what really matters is not how long it takes to go from first putting some ideas on paper to getting the plant built, but what's the difference between when you have irreversibly committed a lot of capital, when you start to pour concrete, and when the plant gets built, that's the point. Because you can have a bunch of generation proposals, and plans developed, and go through the planning process. You pay a few million dollars. You might have to put up some money for a site or something like that. But you don't really sink a lot of that money or spend a lot of money until you start pouring concrete. So, while it makes us nervous, I think people can have a lot more flexibility by just prepermitting some good ideas and then exercising on the permits if possible.

But other than that, I think the political climate makes a big difference. Alberta has been blessed in that sense of there not being too much meddling. But that could change any time. You know, it's very exposed to political changes and legislative interventions, and often well-meaning legislations, like on renewables or clean tech or whatever, can really have a terrible impact on the sustainability of the market.

But I do think there are exportable lessons. One of the lessons is that if people can finance plants in this market, they can finance plants in other markets, too. So I think there are a bunch of good lessons, but the reality is that if regulators, politicians, or system operators can't stomach uncertainty about the reserve margin, then maybe the energy-only market is not for you.

Question 6: There are obviously significant differences between the US and Alberta in terms of differing demand structures, and the capacity additions are typically driven in the US right now due to retirements, rather than here in Alberta, where load is completely different. So, Speaker 1, given these differences, and particularly the fact that there could conceivably be investment and growth constraints for cogeneration in oil sands, I was wondering how you've included this within your analysis, because I think that in terms of generating investments, this is a significant factor that could affect the future. That's my first question.

And the second question is for Speaker 2. In terms of the differences of Alberta and the US for regulation of markets, the differences in how market power is treated are obviously interesting. In terms of how you structured your presentation, I think two of the big differences are, of course, the differences in demand, which I addressed in the previous question, but also the size of the market. So I was wondering if you could comment on that a little bit in terms of how this might affect the efficiency of the Alberta market?

Speaker 1: So your question was whether we factored into our analysis constraints on the cogen developments? Well, we have looked at the cogen economics, and the fact that if you need a lot of steam, and you have gas at the site, cogen is a very logical low cost opportunity, and the economics of being able to sell the rest of it into the energy market make a big difference. So in some ways, I think there's also a natural hedge, because so much of the load growth is driven by oil sands development, and so much of the oil sands development is supplied through cogen. If oil sands developments fluctuate relative to the forecast, I think you will have generation development on the cogen side fluctuate with that. So I would think that creates a net uncertainty on the rest of the system that is not as high as it would otherwise appear.

So we have thought about cogen, but if the question was about regulatory constraints and cogen development, we haven't looked into this, but that doesn't seem to be a problem.

Speaker 2: I'll go for the second question, which was the difference between Alberta and the US in terms of size. As part of our State of the Market Report, we did hire a consultant to survey potential investors and actual investors into Alberta, as to whether they were attracted to invest here. One of the things that was related to size that came out of that was that Alberta may not actually be large enough to attract some of the large US utilities, because we don't need to add that much capacity at any stage. Most of the additions are coming from the oil sands. So what we need in terms of pure merchant investment coming in might be quite small. As the power purchase arrangements retire, that might change.

The other sort of size difference that that survey showed up was, really, there isn't a lot of balance sheet finance capital out there for investing in what essentially is, in Alberta, a risk play. There's a significant amount of risk. You can't project finance things here. Because Alberta is so small, you don't need that many people across North America or across the world that are interested to easily fund what we need to add. And it may well be the case that people who are investing in long contracted capacity in other marketplaces or pseudo marketplaces, or non-markets, may actually like to diversify a little and add some in Alberta, just because it has a different risk profile and a potentially higher return.

With respect to size, you know, we are a load pocket, essentially, in the California scheme of things. So I'm not sure there's that much difference on size. Another difference may be that in Alberta, the load shape doesn't really make smart meters look that attractive for residential customers. Whereas the other difference in ERCOT is, the case is overwhelming that that could be an enormous resource there. So there are some fundamental differences.

Moderator: I'll maybe add a little bit to that answer. The commission actually did a smart grid inquiry, I believe, back in 2010, and engaged Brattle to help them out on that, and that report should be on the website if you're interested in that as well.

Question 7: For Speaker 3, I'm still looking at your slide ten, where you're going from roughly 27,000 megawatts at 3:00 in the afternoon, to about 42,000 two hours later. For some of us, that's a little bit intriguing. And you talk about a flexible ramping product, which I'm not sure I fully understand. I mean, we could visualize all the Teslas going down highway 101, getting a signal about 3:30 to pull into charging station. I mean, that's one form of a flexible ramping product. But practically speaking, what are you realistically thinking that product would look like? You were talking about a bid-based product, but is it just traditional demand-type bidding into the market, or what?

Speaker 3: Let me try to address everything I heard. First off, you mentioned you're intrigued by that ramp. We're terrified by it. [LAUGHTER]

In terms of what resources would meet that flexible ramping product, our view is, anything and everything that can. So the notion on the flexible ramping product is that operationally, when the optimization looks forward, trying to anticipate what that ramp is, when it's going to kick in, how long it's going to last, how high it's going to get, recognizing there's a lot of inherent uncertainty around all of that. So we need to secure sufficient head room with the resource mix we're dispatching, so that if the target dispatch turns out to be wrong, and we actually need more, the capability is on the system to provide it. So that's effectively what this ramping product is. It's buying a reserve in anticipation of that multi-interval look ahead that there's some uncertainty around that, and any technology that can provide it, if it's a demand response resource, we would love to see that in the market, providing that, and we've really tried to knock down some of the barriers for DR participation in our market. The storage device could help contribute to this. And of course, conventional generation as well. So we're trying to be technology neutral in designing this in a way that doesn't necessarily inhibit cleaner technologies from providing it.

Question 8: I'm fascinated by the Alberta pool, and the idea that it's sort of a substitute for coming up with a scheme for capacity and dealing with missing money, and it will just allow the exercise of some measure of unilateral market power. And it seems to be working. But going way back to the beginning with these energy-only markets, the first objective, and the reason why people were thought to be encouraged to bid marginal cost, was to get economic dispatch. From looking at your diagrams, it looks like in, say, 5-10% of the hours, you have at least some people bidding something above their marginal cost pretty broadly. Have you looked at whether or not that hurts the economics of dispatch?

Speaker 2: Yes, we've done a report that looks at static efficiency losses that would come from economic withholding or ramping people at the wrong times, or other things--it's not just economic withholding. And what we found was the static efficiency losses from dispatch efficiency and allocative efficiency losses (so that is demand response responding when otherwise they wouldn't have responded, because the price would have been at marginal cost, and less than 1%). So for those of you that are in the consulting game or the academic business, we could definitely do with some help in refining the methodology. It's not dissimilar to things that have been done elsewhere, but it's a really interesting question. What we find in Alberta is that for a lot of our technologies, our marginal costs between all our technologies are not that dissimilar to one another, particularly as coal here is extremely cheap. The mines tend to be just across the street from the power plants. Natural gas has become very cheap as well. So in very simple terms, it doesn't really matter which order you dispatch them in. The costs of production, as it were, are relatively similar.

Questioner: And just so I understand, without getting into the weeds, when you say 1%, that's comparing what to what?

Speaker 2: That's if we sum up the hourly cost and compare it to the pool price.

Question 9: I have two questions. One's actually a clarifying question, and with the other I sort of want to provoke a discussion on Alberta. The clarifying question is on the California imbalance market. I'm interested in what are you really trying to accomplish with that, number one, and number two, what do you think the impact on the market will be? Because that's a bit murky to me. So that's question one.

Speaker 3: In terms of the energy imbalance markets (so this is the market that started out initially with the ISO and PacifiCorp), the objectives really are to provide an opportunity for mutual sharing of imbalance resources to more optimally dispatch the needs between our respective balancing areas. There's broad interest in this throughout the West. This has been a topic of discussion the last couple of years. PacifiCorp was the first entity to really step up to the plate and work out a venture with the ISO. But I can tell you, at least among the US entities, and frankly, even BC Hydro, there's strong interest in broadening this EIM concept. In terms of its impacts, we're not envisioning this market having a huge impact overall, in part because of the limited transfer capability between our respective systems. So as it stands, I don't think the EIM itself will have a dramatic impact, particularly when you look at relative to everything else that's going on in the West with the whole change out of the resource fleet. I think this will pale in comparison. But for both of us, I think it will provide significant benefits in more efficiently meeting our real time needs.

Questioner: Thanks. And so the second question was, and I'll just frame it here… First of all, I'll agree with the panel that Alberta is a great market, and there's a lot of it that's working. Clearly part of that comes from the underlying conditions. And it's also a willingness in the province here to let the market work, which is fantastic.

There is an assertion made, first of all, that what we've been able to accomplish is a price signal that incents new generation to come in, and that's largely been provoked, I would say, by the OBEG, the offer behavior enforcement guideline. And, secondly, that it probably doesn't allow project financing to finance new plants, but somehow balance sheet financing would. I guess there are two questions I wanted to provoke. One is, do you think the OBEG is a stable enough policy framework to last? In other words, is it stable enough to allow people to finance, given that it's a guideline, not a formal policy? And then, secondly, I'm not sure I get the distinction, especially given that a couple of major participants in the market have said that they wouldn't balance-sheet finance things without long term contracts. So I'd like to hear your views.

Speaker 2: Sure, you know, we have asked for a survey of those who invest in power plants, and the result of that survey was, yes, there is sufficient interest. It's more of a case of how high does the price have to go? Everyone that can balance-sheet finance has another opportunity to invest in something else that also has a return. So the downside of the Alberta market is, we're competing against other uses of capital, other uses of balance-sheet financing. So it may well be that for some that have access to balance-sheet financing, they've got something better to do with it, or they prefer to invest it in another electricity market, where there's lower risk. So one of the fundamental questions about Alberta is just how high do prices have to go in order to attract investment? That will be determined by the market, not by the regulator. And what we found thus far is, they don't have to go that high. And there's a lot of hand waving there about what's high and what's not high. But you've got to accept that there are cheaper ways of financing.

If you do issue long term contracts, you could say that there's a massive gain to society in that, because we get access to cheaper capital. I don't think that's been the experience of Alberta. I think it's worked really well. We don't need everyone to balance-sheet finance. We only need a few people to balance-sheet finance, and the threat is there that project financing will come along at the end of the day once prices rise high enough. Personally, I don't think it will ever happen, because there will always be someone with access to balance-sheet financing that will be there.

The second part of your question was around the Offer Behavior Enforcement Guidelines. Guidelines in Alberta are not law. They're not rules. They're just clarifying statements that the market surveillance administrator gives out. So economic withholding of the type that we see now, it happened frequently in our markets since 2006. This is not a new phenomenon. It's new for some of the market participants, and certainly the offer behavior guidelines equalized, if you like, the kinds of behavior that a wider range of people were prepared to undertake. Some people were kind of holding back from it. So I think that's good. Will they last forever? I suspect so, unless the underlying legislation changes. The root of them comes from the legislation. They're not rules themselves. They're just guidelines. If the rules change, if the legislation changes, obviously our guidance would be different. But I don't think there's any great risk of the guidelines changing at the current time.

Now, it's fair to say, though, that I would encourage people who are interested to look at the guidelines. It's not a free-for-all, in which all kinds of behavior are OK. The guidelines actually list a whole bunch of things that are not OK. The rules behind them are essentially a principle-based system. There's a conduct standard that participants must meet, and then various things underlying that. So it's not like it's an unregulated market. There are regulations in place, and specific ones that are different from general Canadian competition law. So don't get the wrong impression that it's not that.

Speaker 1: I just want to add a few things. First of all, I think the offer guidelines are uncertain. I mean, can you really finance a 20 year asset on just that? And you wouldn't. But I also think what's more uncertain is how generators bid within the context of these guidelines, because they could change that bidding and still be within the guidelines, and you can see very different market prices. What we found is, if they kept bidding the way they bid in 2011 and 2012, you would make a lot more than the cost of new entry going forward. If they bid more like 2009 and 2010, it would be a lot less, and our projection takes the average of that, and that makes it about right. But there's a lot of uncertainty. The uncertainty is less for incumbent generators adding their own new generation, because they have some control over what they're bidding themselves. But I think that kind of uncertainty will make it more difficult for third parties to come in, totally new, they only have one asset, and they're totally at the mercy of the bidding behaviors of the incumbent generators. And that risk is one I'm not sure people are willing to take on.

Questioner: We don't mind that, by the way.

Comment: But we do.

Speaker 1: But that's why we thought it would actually be very helpful to put in a scarcity pricing curve with a higher price cap, because that would create more predictability on the down side for new investment, even though at the current bidding levels it wouldn't make a difference.

On your questions on project financing, it's not an either-or. People told me that they can easily finance 30-40% through project financing in the Alberta market. It just means, rather than financing 70% with debt, you can only finance 30% with debt. And you do need some equity. And the equity funds out there, I mean, even if you don't have the balance sheet, you might be able to find equity willing to put the money in, and that's what we're seeing in Texas, for example. The Panda deal is very interesting, because it's all through an equity fund, and even the project finance that they have for about half of it doesn't come from banks. It comes from non-traditional sources.

So there's a lot of innovation going on. But ultimately I think what investors are doing and what they don't do, it's sort of a game of chicken, because we've seen the very same people tell us that they would never finance anything in PJM or in Texas, only to have changed their minds six months later. There is a lot of money at stake. So why would somebody who thinks they can just about make it, why would they say, "Oh, yeah, we can just about make it?" The incentive is to say, "Look, this is really hard. I don't think we can make it." And then they may not even know. Somehow they can cut a deal. They're negotiating with investment banks, and ultimately they can make it. You don't need to have everybody make it. If it was that easy, we wouldn't have a competitive market. You only need the people who have the best ideas, the best site, the best plants, and the best financing structures to make it. But then, of course, the question is, how much do you need? And if you need a lot of capacity all at once because of retirements and so on, you might get into trouble.

Question 10: I want to return to the CAISO terror with the load ramps. I guess in particular my question relates to slide 11 from your pack, Speaker 3. What assumptions are being made with respect to solar build in terms of how much of that is coming from utilities, and how much of that is coming from smaller-scale PV installations, and what differences you see with those two different types of build out? And how is CAISO planning around those assumptions?

Speaker 3: For the renewable portfolio assumptions in slide 11 (which we refer fondly to as the "duck chart"), we rely on the portfolios the public utilities provides us. So they're overseeing the procurement of the utilities. So that includes the large scale solar projects, PV, solar thermal, as well as assumptions about rooftop and distributed generation as well. I don't have all the details. I could certainly provide those if you'd like to follow up with me. And this is a chart that we do update. I think we'll be updating it every year. So as those portfolios change, we'll be reflecting them and an updated analysis. But frankly, I think the basis trend that you see depicted here is not going to change appreciably with any updates.

Question 11: This is for Speaker 3. You talked about procurement by government and ISO, you guys are thinking about that. Maryland and New Jersey tried it in different ways. What do you guys have in mind, and is it specifically procurement by a state regulatory authority to build in certain areas, or anywhere within the ISO?

Speaker 3: Well, the focus has been primarily on those midterm years that I highlighted in the graph, those years three through five, where because we have this dramatic shift in the resources mix, and you have renewables displacing conventional generation in the year-ahead resource adequacy procurement, you create the potential for a gap, where a resource you might need three to five years from now because of all these OTC units going away, is not needed today. And they're not needed next year or in year three. So they're just hanging there with no market revenue. You saw the revenues in our spot market don't provide any real cost recovery there. So a big concern there is bridging that gap so we don't have premature retirement of units that we know we're ultimately going to need three to five years out. So that's the dynamic we're trying to mitigate.

So what sort of framework can we put in place where we make sure we're staying ahead of the game to identify what those needs are, and secure those resources in advance, so that not only do they stick around, but they have a revenue stream and an incentive to actually enhance their capabilities to be more effective in providing that flexibility service? Longer term, when you look at the once-through cooling units going away and building new generation, the state PUC has a long term procurement proceeding where they evaluate that. CAISO participates in that, provides analysis and ultimately the PUC issues a decision authorizing the utilities to procure a certain amount of new generation to replace whatever needs they see on the system.

So we're not looking to modify that long term procurement. We are really focusing on that medium term, and whether, in addition to whatever the state might do, the ISO might consider a centralized capacity market similar to PJM that's looking out three years ahead. And that's where the debates that I'm sure you're very familiar with about state versus FERC jurisdiction are playing out in California.

Question 12: Thank you. A question to Speaker 4 about the ERCOT market, and if you can comment on any correlation with forward contracting and the increase in the ERCOT price cap. So, have consumers responded to the price cap increases by being more active in forward market transactions to avoid real-time prices?

Speaker 4: Yes. The answer is yes. The forward price curves have gone up. I don't have those exact numbers with me today, but we have seen that occur. One of the challenges that I didn't talk about in ERCOT that is a good thing but is also challenging is that we have a very robust retail electric market. So there's a lot of customer switching between retail electric providers, and the contracts that they enter into are sometimes six months to a year. So although the forward markets reflect the higher offer caps, how far in the future these PPA agreements go also has an impact on investment as well.

Question 13: This is a question for Speaker 3. You mentioned a few different times in your talk that you had transmission constraints around the OTC retirements and also, then, in the imbalance markets. How does transmission get evaluated? And wouldn't more transmission be advantageous and helpful rather than just saying, you need local generation? And especially HVDC, would HVDC help with some of these operational issues that you have coming up?

Speaker 3: OK, on the discussion around the once-through cooling plants retiring, we do have some load pockets, most notably the Los Angeles Basin, that we're very concerned about in terms of making sure we get sufficient replacement there. We are looking at transmission options as well. As you might imagine, Los Angeles is a highly difficult area in which to site transmission. So part of the challenge is in evaluating options. You can identify things that on a network map look great, but look at the practicality of actually building those projects. It's really practically almost insurmountable. But that's still under review. Transmission's got to be part of that solution. And certainly your question whether HVDC can play a role…I can tell you, some of the proposals put forth for the LA Basin consider possible submarine cables off the coast to overcome the siting issues in that densely populated area. So there will be a lot of activities in our current transmission planning process to look at those options, if you're interested. I'd urge you to participate in that. It's all noticed on our website.

With regard to the EIM, the limitations on transmission there are more about the rights that PacifiCorp has currently to actually shift power to California. It's more of a contractual limitation in terms of what they have. So that's something that can change over time as that market evolves. But in terms of physical limitations, that's not the big driver.

Question 14: I was wondering about the megawatts that have been added over the last several years, and then the megawatts that are planned or have been announced going forward. How much of that is associated with the oil sands and driven as much by the energy market economics as by the steam or cogen market economics?

Speaker 1: Of the total, I seem to recall maybe half or two thirds of the delta might right now be in cogen.

Moderator: We have all the exact numbers. We can get those to you. But certainly on the generation build side, there's probably a couple of thousand megawatts of cogeneration that we're expecting to come in to the oil sands area specifically.

Speaker 2: There's a big combined cycle plant being built in Calgary. It's 800 megawatts. That's obviously not for the oil sands. So there is significant investment elsewhere. But certainly most of the growth is in the oil sands.

Question 15: This question is for Speaker 4, but as a follow up I'd be interested in commentary from anybody from the Alberta side of the question. When you were talking about the backcast that was done on the Operating Reserve Demand Curve, I think you said the conclusion was that it generally supported 13.75 % reserve margin in ERCOT, but that that was difficult to predict because of a lot of behavioral aspects. Could you talk about what those behavioral aspects are, and to the extent that any of those are relevant, or any of the other panelists who have experience, particularly from Alberta, with regard to those, if they have any thoughts that might be illuminating for the folks here today?

Speaker 4: Sure. What we did is take the actual operating reserve levels that were observed in 2012 and in 2011. We calculated a price at those operating reserve levels, and then the added it to the marginal energy price that was actually realized during that interval. Now, what we found is, when we did that, that the revenues that I showed you in both years would support a 13.75% reserve margin. In fact, I didn't clarify in 2011 that the $400,000 number was, will be, would be obviously overstated, because there were some rules that when you reach certain thresholds, you lower the offer cap from high $9,000 offer cap to $2,000. And so I didn't try to clarify that. But as far as the behavior aspect, there are some intervals where the price gets high, and you would expect that units that can start very quickly, in 30 minutes or less, would come in, they would start up, and they would take advantage of that price. So it would tend to dampen out the revenue that was shown in the backcast. However, the challenge, when you do a planning model, and you look forward, is that with a planning model you're going to assume perfect behavior, and that those intervals will always be dampened out if there's excess capacity in that. And that's not exactly true, either. Because there will be times operationally where units will trip. You'll miss the load forecast, and there's not just enough lead time for some of your slower units to start and take advantage of it. But as far as the backcast overstating a little bit, it could, because of the fact that units that can start very quickly that are off line would tend to take advantage of the price that's there.

Question 16: One challenge that we've had in dealing with markets that don't have a capacity program, they're using price as a means to incent generation, is that it adds to the challenge of providing efficient market pricing from a margining standpoint. Every day our clearing house is trying to capture a one day move based on volatility with 95% confidence. And in markets that have a price that is $4,500 or $9,000, you're dealing with the need to margin to capture those potential outlier events. But when they do happen, it can be very destabilizing from the standpoint of the impact to the clearing firms. And to the traders as well, in terms of having a generation plant or a transmission line down. No one expected that. And suddenly the $30 market has become a market that's in the thousands. It's a reality that we have to deal with every day, that we're providing electricity risk management. It's an issue that's much more focused on daily contracts, more so than monthly contracts, because it's the daily that could be the most severely affected. And I'd like some comments, particularly from Speaker 1, who has the inclusion of the substantially higher cap, in terms of the interface between use of a higher cap to incent generation and the potential impact to risk management operations through higher margining and related processes.

Speaker 1: Well, that's a very good question. Let me just ask you, do your daily contracts sell against a day-ahead price or against the real-time price?

Questioner: It depends on the ISO market. We have constructs to settle both in real time and day ahead. It really has been a function of what the market's preference is. As an example, in PJM, we have both day ahead and real time. In ERCOT we have day ahead as well as real time. But the driver is what the market preference is. And well developed markets will typically offer both real time and day ahead, peak and off peak, daily and monthly. And sometimes options.

Speaker 1: The reason why I'm asking is because we focus a lot on the price spikes in the real-time market. But even in a day-ahead market, you don't see many of those price spikes, because you don't quite anticipate it, you know. Even in 2011, I think there was a big difference between the day-ahead prices and the real-time prices. And if most of the transactions are really cleared against the day-ahead price, and the real time is just an imbalance market, the level of at-risk is smaller than it appears. At the same time, we did find even generators being very concerned about those $9,000 possibilities, because if they bid into the day-ahead market, and then they have an emergency, and they are down for a day, they're exposed to that full difference between a day-ahead market and the real-time market on their entire plant. And some of that cannot readily be hedged through forward contracts, but we found that some of these generators actually team up with demand side response providers, so that if they had an emergency like that, they would actually have somebody to share the load. And so they physically hedge what is a challenge financially.

So I think it does create some additional challenges, but I think whenever you add a challenge, people figure out a way to innovate around that. And I do think that overall, you have to have the possibility of prices rising to the several thousand dollars level to just get demand response into the picture. And even from a plant operational perspective, there are some advantages. And if it serves a purpose in that more people are hedging, then I think the hedging products will also become more liquid, and maybe it's not going to be as challenging to do that on a purely financial basis.

Question 17: This is a question for Speaker 2. In your presentation, you had a slide that listed some questions to think about. And one of them, number four, was whether electricity markets are exposed to the potential for coordinated or consciously parallel conduct. And at least in your experience, do you believe you've got the means to identify what I'd call "implicit collusion?" In other words, cases where there's not an expressed agreement, an explicit agreement, but in fact there is collusion. Or does the danger of lost opportunity mitigate the problem? Because in ERCOT we found an interesting phenomena, which is that we allow small generators to bid whatever they want, and the fact is they don't. The reason why is because they lose the opportunity for too much revenue over time.

Speaker 2: Yes, I'll take the first point first. Small generators in our market act as price takers. They don't have market power. Their optimal strategy is to take whatever price is given by the market. Large generators here do exercise market power, and the real difference is, you know, if you've mitigated offer prices, you don't let people offer freely. One of the side effects is, you get rid of the problem of tacit coordination or collusion or all those things, because you just made it impossible. So if you don't have limits on offer prices, it does turn out that that is a concern, and if we come from sort of a normal competition antitrust perspective, that's the primary concern that we have.

We did a report with Charles River Associates, they did a report for us back in 2011, I think, about the susceptibility of Alberta's electricity markets in general to those things. You know, we give out tons of information about what's going on in the market, and it's very easy to see whether or not you've had an influence on the price very shortly after it's happened, and then to change your behavior very shortly thereafter. That's not the case in many markets. So this is a very live concern for us. So we indicated that. If you go back to the Offer Behavior Enforcement Guidelines, a whole section of that is about this being our real primary concern going forward. And we have a couple of active concerns right now.

Question 18: Thank you all for a very informative discussion, and good questions around the room. Sort of as a lead-in to the panel presentation after lunch, I wanted to make a point and then also ask a question of the entire panel. The evidence that we have to date is that energy-only markets are anathema to demand response. And I'll point you to maybe the purest example, which would be the National Electricity Market in Eastern Australia, where the current market cap is somewhere north of $12,000, and is hit on a regular basis, and sometimes for extended periods of time. Less than 1% of the 40-some-odd thousand market is DR that participates. We're not sure why. We're working to change that. They're allowing DR to participate as a wholesale supplier in the market to see if that makes a difference.

But where we have these energy-only markets, the only place that you see DR participating in any way is where there is some sort of availability payment. I won't use the C word up here, but some sort of availability payment, where there are sort of fixed payments provided. And then you look in the East, where there are capacity markets, and it constitutes up to 10% of the marketplace. So we've got NERA looking at some of the ins and outs of that.

But given that, does DR have some sort of an inherent value such that it makes sense to either create a capacity market, or to create these availability options outside of that market, such that you actually have a significant amount of DR? Or is it OK to sort of let the chips fall where they may, and if the energy-only market results in very little demand response, then that's just the way it goes, and we really don't need the demand side operating on the other side of the equation? Thank you.

Speaker 1: Let me offer a couple of thoughts here. First of all, there are very different types of flavors of demand response. And active participation of demand in bidding into the wholesale market is only a portion of, and possibly a small portion of, the demand response potential that we're talking about here. It takes a lot more for demand response to be able to follow dispatch signals from the ISO. So necessarily that's going to be limited. There you will have sort of LSSI (Alberta's Load Shed Service for Imports)-type availability payments if you need that for operating reserves, or things like that. But I think there can be a lot more passive demand response, where load just looks at the price and says, "Gosh, prices are high. I'd better cut back a bit." And we have seen, when we talk to people in Alberta, that folks are institutionalizing that. I mean, there are firms out there that help folks to curtail their power very easily to reduce their power consumption purely in response to the price signals. They never bid into the ISO market. There's never a baseline or anything like that. And I think that's where probably a big portion of the potential is in the energy-only markets. But for that to happen, I think you do need price signals that are high enough.

What's interesting, you know, is that in ERCOT, generators go out and sign up load that could be shed so they can hedge their own exposure in case they are down during a $9,000 price spike. So I don't quite agree with the proposition that just because there might be fewer megawatts actively participating in the wholesale market that it's necessarily more limited. But I agree with you, it's a much harder business model for companies like Enernoc to make that work. It ought to be a different business model in energy-only markets, because you don't have the availability payments. I don't know enough about Australia, but if you have enough reserve margins all the time, and you never get these price spikes, except once in 20 years or something like that, you know, why would customers go through the trouble to be ready for it? They just sign a seasonal contract and never get exposed to any of that. So it's going to be a little bit of a struggle, I think, to get to scarcity pricing that really sets the proper price signals more frequently, because part of what ERCOT is now trying to do with Bill Hogan is to get the prices right, to get better prices that really reflect that when they deplete operating reserves that prices should be high and not low. So I think that as you fix energy-only markets, and as you allow for some scarcity and allow for some high prices during those scarcities (and we also had some other recommendations to make it easier for demand to respond to prices such as short-term price forecasts), you can actually draw more people in, and that at least is my hope.

Session Two. Demand Response: What Is It?

Demand Response (DR) the subject of broad consensus and extreme controversy. While there is agreement that DR is a welcome product in the marketplace for electricity, that accord breaks down rapidly when confronted with such questions as how to price it and, perhaps even more basic, how to define it. While HEPG has discussed pricing, the more fundamental questions have been less examined. The theory was captured best by Amory Lovins describing that negawatts are a desirable product in the marketplace. The problem is defining what constitutes a negawatt. How do we know for sure what a consumer would have consumed in the absence of a demand response mechanism? What is the baseline from which we derive the volume of demand response? How do we know that historic consumption numbers are relevant given changing market circumstances for what the customer produces, less sophisticated electricity pricing in the past, and economic cycles? How, if at all, can we normalize for all of those variables, much less others that might be relevant as well? How do we differentiate charging for use versus paying for non-use? What other ways are there to accurately determine the level of demand response that merits compensation?

Speaker 1.
Thank you so much for the opportunity to be here. I like the way that the panel was cast as "demand response, what is it?" Because it gives me the opportunity to say, "It is this, that and the other thing." Here is, at least in the States, the legal definition per FERC of what demand response is: "A reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy." FERC 18 C.F.R. s.35.28(b)(4).

I think most of the people in this room have a pretty good idea of what DR is, but it's basically loads responding to either prices or dispatch signals from the system operator. Given that we're talking about FERC, that's usually in organized markets, but there's usually DR that exists with utilities as well. There's a lot of it in California, dispatch by utilities. So it need not come from the market operator. It could be the local distribution system operator.

So it is a substitute, albeit imperfect, for generation. But it is not generation. So while there is a very limited subset of demand response that is supported by behind-the-meter generation, and that that generation is permitted environmentally to be able to operate for economic purposes, except for that, it comes from customers who are sort of inherently limited in their ability to produce megawatts. Their jobs are to make people comfortable, to build widgets, to do all the things that customers do, or to stay comfortable themselves, and even where they have backup generation, and that supports the resource, typically its ability to operate is very limited. In some cases it's lights out situations, which is a little late for doing demand response, but in other cases, it's in order to prevent a blackout, if you have reserve shortages or forecast reserve shortages.

On the other hand, for generation, their job is to produce energy when it's economic to do so. Their sole reason for existence is to produce megawatt hours. So it shouldn't be particularly surprising that the requirements and the treatment of the two resources ought to be somewhat different. Customers are not in the business of producing megawatt hours, and generators are.

So that's one thing to keep in mind. They are substitutes, but they are not identical. And so when we talked about comparable treatment, "comparable" doesn't mean identical treatment. So these are not industrial rate discount programs in drag. A lot of the experience that people have with demand response is interruptible rate programs, and most of those (though not all) are either cogen referral rates or just plain rate discount programs. And most of them are seldom, if ever, called or even tested. Now, again, that's not *always* true. In some cases they are called on, but in many cases they aren't. And quite often when they all called or tested, they elicit howls of complaints from customers who never thought they were actually going to have to reduce.

Real demand response is resources that actually do respond when called upon, and they do so in a predictable and reliable manner. For the most part, these types of programs, if you look at the amount of demand response that isn't an interruptible rate program, you will find that the large majority of it comes from and is aggregated by companies like EnerNOC, curtailment service providers, aggregators of retail customers, if you will, but that's where most of the DR comes from, and certainly that is true in the organized markets in the East and in the bilateral programs that exist in the West and in California, which is also in the West.

We like to think of demand response as dynamic pricing on training wheels. So DR and dynamic pricing, I think, are basically economic substitutes. You can achieve the same ends by either means, but for a variety of reasons, uptake of dynamic pricing by customers has been slow, even where it's been offered, and it's been heavily promoted. DR, on the other hand, has flourished. It seems to be the case that being paid to reduce your usage is much more compelling and attractive, especially to large customers, than being charged less, even though economically the options ought to be equally attractive. There seems to be something about customers getting a check that is meaningfully different than the opportunity to pay less to their utility or their retail supplier. So maybe someday customers will shed their training wheels, but that day is not today.

DR is readily measurable. We believe that this is a solved problem. It's not child's play, but it's not rocket science, either. There are some people that would say that it's more art than science, or even less charitably, more witchcraft than art, but that is really not the case. PJM, for example, has gone to some significant amount of effort to develop different baselines that ensure that customers are getting what they are paying for and minimizing opportunities for any kind of manipulation--which can happen.

There's always going to be the ability for somebody to misrepresent what they're providing, whether it's a demand response provider or a generator. It may be a little more difficult to fake the metered output of a generator, but you could do it. There are probably something on the order of 20,000 different customers that are participating in the various eastern RTO programs. I think we've got less than five cases that I can think of offhand where FERC had taken people to task for being naughty. And that's not a bad track record, especially when the industry itself is only ten years old, and some of these economic programs even less than that. So, yeah, there's going to be some bad actors. I think FERC and the ISOs have done a good job at ferreting them out. But when people raise that, or the potential for inaccurate baselines as the reason for not proceeding with some of these programs, I just think back to words like "death star," and some of the stuff that happened out west, you know, during the California crisis. Any bad actors in DR are pikers by comparison to what happened out there. I mean, you're talking about a few hundreds of thousands, maybe millions of dollars, as opposed to hundreds of millions, maybe billions, of dollars that manipulation produced. So we don't want to have people out there manipulating baselines, but at the same time, I think we need to put it in perspective, and ask ourselves whether we really want to rule out an entire class or resources simply because there are a handful--probably less than a full handful--of situations that have not gone the way they should have.

So here's another thing demand response is: it's as or more reliable than generation. Individually, taken on a customer by customer basis participating in these programs, maybe not. But as brought to the ISOs and to utilities as aggregations by demand response providers, every place where we've seen metrics calculated, which is basically all of the organized markets, we've seen what would sort of be the equivalent of a forced outage rate that is well above industry averages for generators, and even more so for peakers. Typically, we have performance rates of over 100%. Are all of them over 100%? No. It's an average. There are some programs, some dispatchers, that don't work out that well. But it is clearly a reliable resource, and the ISOs and the RTOs consistently have reported that to FERC, or in the case of individual utilities have reported that to their public service commissions. So I don't think anybody should be too worried about it being an unreliable resource. And, actually, I don't typically hear that as a criticism. It's basically because the law of large numbers works in our favor. Where one customer or two customers may be down, there's going to be others there to replace them.

Next (this is one of our favorite ones) demand response is hugely beneficial to customers. So in this delivery year, the delivery year that begins June 1st and runs through May 31st of next year in PJM, the market monitor did an analysis of the base residual auction for this current delivery year, which was held three years ago, and determined that, had the DR not been in the market, the cost paid by consumers, and conversely paid to generators, would have been $11.8 billion higher than it was. It's a little rough to get a handle on the total DR expenditures, but they fall somewhere between $200-400 million. So that to me strikes me as a pretty cost-effective solution. Very beneficial to customers. Problematic for generators.

Demand response is also the gateway to energy intelligence. There's a slide I read earlier from somebody about the relationship between demand response and energy efficiency. And the two are not identical. But there's absolutely no question that once customers get engaged with their energy spending (and it's amazing the amount of time and money people spend looking at their telephone bills compared to the minimal amount of time they often spend looking at their electricity spending), once these guys are involved in DR programs, and they're seeing their real time usage--a lot of CSPs provide them with real time metering and visibility into that--they suddenly become aware of just how much money they're wasting. Some of that can be alleviated through operational efficiency changes. It doesn't cost anything in terms of capital. But in looking at that, they will also identify capital changes, and so one of the things we would like to call it is "energy efficiency in a hurry." There are things that you can get right away, within days, weeks, that are significant savings to customers, to say nothing of the additional capital expenditures or investments that could be identified.

Demand response is an integral part of any efficient market. I think this is an uncontroversial statement, but I'm not 100% sure. When we litigated the case that led up to Order 745, the DR compensation proceeding, which is the only time I'm going to use that phrase, we saw a lot of testimony by just about every regulatory economist that's active in this industry. And I think all of them agreed that DR is an important part of an efficient market. There was a lot of disagreement about how much it ought to be paid, or who should have jurisdiction over it, and certainly how it should be compensated, but I don't think anybody basically said that not having DR wouldn't be a bad thing. So I think there's agreement on that. A single sided electricity market, we think, is a market failure. And I think it's questionable that any market that doesn't have--this sort of is a not-so-veiled impugning of some of these markets that don't have a significant amount of DR--it's questionable whether or not you can say that they actually produce "just and reasonable rates," without having the second hand to the otherwise one hand clapping argument.

Demand response is also a disruptive technology, one of the most disruptive technologies that's come along in a while, as evidenced by panels like this and all sorts of conferences and litigation and all the rest of it. And it really threatens the generation business model, because DR excels at, more than anything else, clipping the super peaks. It's good. Customers don't want to be called frequently, so 10, 20, 30, 50 hours is what it's perfect at doing. It can do it at very low cost. That's why you see it continuing to bid into the markets, even when the prices drop by 50%. With some additional effort and maybe lower participation, it can also do it for a lot longer than that. But these super peak periods are where a lot of suppliers actually make a lot of their money, and so having this new resource that sort of shoehorns its way in and captures those dollars has really shaken things up, and I guess it really doesn't surprise me that the reaction that we've gotten is as significant as it is.

And I guess the last thing is this. Demand response is here to stay. We're not going anywhere. Currently, EPSA (the Electric Power Supply Association) has a case pending before the DC Circuit that would, among other things, strip FERC of its jurisdiction over wholesale demand response programs, which potentially would erase all of these programs that I've just been talking about. If FERC doesn't have the jurisdiction to approve them, then presumably those programs are illegal. That, we think, is pretty unlikely, but were it to occur, I think at this point it's pretty clear that regulators and customers and politicians and other folks have gotten a taste for this stuff. It's not going away. If FERC can't require it through wholesale markets, then there's certainly nothing stopping every state regulator from having the utilities in its jurisdiction implement these programs, as they have in other states. So we're not going anywhere. And I'm not sure that having it under one big fence with FERC may be a preferable alternative to having 50 different very independent minded commissions doing it 50 different ways in 50 different states. So I guess, be careful what you ask for, because you just might get it.

So demand response is an idea whose time has come, not only in North America, but globally, and to not incorporate it into the system makes it nothing sort of cheating a region and its customers.

Speaker 2.
I have a couple of disclaimers and a context to offer. I think, frankly, that the fact that we're even asking the question, "what is this?" after so many years of it being debated, and it being paid so much, in some respects, should be a cause for concern, and we'll get into that. I thought the description for the panel was very well done, and going back to Amory Lovins and "negawatts," and I found it actually very fascinating to do something I should have done more recently, and that's actually read the

entirety of what he wrote 28 years ago, which we'll get to in a minute. What we'll find is that Amory Lovins captured the theory, but then said the problem is defining what constitutes a negawatt. If you actually go back and read what he wrote, he was very clear on what "negawatt" means, and it does not mean what we have come to call demand response. So that's why I've asked the questions we'll get to about whether or not the programs that we have today are in fact producing the negawatts he talked about. And of course it matters, because money that's being paid for demand response is money that's not being paid for generation or for other resources, and we can talk about that, and, finally, what sort of improvements might be necessary.

In terms of disclaimers, obviously it's a timely topic for all the reasons that we know. In PJM and New England and elsewhere, it's been anywhere between one third and one half of the reserve margin the past several years. And of course, Texas and California are looking at it. An important disclaimer: as much as I like to talk about demand response, sometimes I get worried that the message is that that's all that we care about, or that that's all that it's important to discuss. And of course, there really are many, many other issues across the entire set of markets--energy, capacity and ancillary services--that need to be addressed. And as to the pending litigation, I'm pleased to say it's not EPSA v. FERC. It's EPSA, Edison Electric Institute, the National Rural Electric Cooperative Association, American Public Power Association--and the litigation spans more than jurisdiction, although that's an important part of it. And it's pending. The oral argument will be this fall. The decision will be made next spring, and that will settle the legal matters, of which there are many.

I tried to somewhat humorously call this next slide, "Justice Scalia meets Amory Lovins." Because if you actually go back, and thankfully *Public Utilities Fortnightly* just this past March reprinted in its entirety the article from 1985 entitled, "Saving Gigabucks with Negawatts," which was followed by both speeches and articles entitled "The Negawatt Revolution" in the ensuing few years. And the conclusion that you have to reach if you actually read the entire article is that Lovins was talking about trying to bring about energy efficiency and deployment of energy efficiency devices. In fact, if you go through the list, he actually talks about appliances, motors, all kinds of things. It was all technology based. Better lighting, mechanical systems, household appliances, photocopiers, electric motors, compressor stations, aluminum smelters, and all the rest.

And most importantly for purposes of trying to decide how to define this, in order to decide where in the wholesale markets, it should occur, or if it should be a retail product or some combination, he actually offered two recommendations. The first was called the "most elegant" concept, and that was actually ten year contracts. That's significant. Ten year contracts. So you actually would be getting closer to energy efficiency being a substitute for generation. And in these ten year contracts, you would have auctions, and you would actually be having generation resources and energy efficiency equipment, so you'll know you'll actually be getting the reductions. You don't have a baseline issue. That was the proposal that he called the most elegant. And then the other exciting concept that he offered was to actually have customers enter into legally binding, enforceable covenants, promising not to use more than a certain amount of electricity at any given time. And I think, again, that's where you actually get the comparability between generation and energy efficiency, and that's what negawatts were supposed to be about, as

Lovins wrote 28 years ago and talked about it subsequently.

But then if you trace the history of this, somehow after the writing of the article in ’85 and the subsequent speeches, the first time this appears in statute, that I’m aware of, is when we get to the Energy Policy Act of 2005. And the provisions on demand response were not really very heavily debated, were not the primary focus of the legislation, which people might remember were almost across the finish line with the prior Congress and then came back in 2005. There really was no definition of what demand response was, or is, other than to say, “time-based pricing,” which I think is significant, “and other forms of demand response…whereby customers are provided with electricity price signals…” While there was mention of reducing barriers in wholesale markets, the emphasis, by virtue of what the legislation tasked the Department of Energy to do, was actually to provide technical assistance to the states.

So if you go back to when the article was written 28 years ago, the effort and the emphasis was on utilities, not on wholesale markets, and similarly in the 2005 Act, the emphasis was on federal agencies providing technical assistance to the states. Then two years later, in the Energy Act in 2007, a National Assessment was required, and with FERC’s Order 719 in 2008, you start to get the seeds of the definition that Speaker 1 started out with, which is where you get at these baseline definitional problems of saying, “We’re going to pay people based on what they would have used had they not been given an incentive payment.” This, I believe, has its origins in the Department of Energy report of February 2006, which is one of the reports mandated by the 2004 legislation, and then this same definition kind of gets picked up, and people keep referring back to the 2006 definition. And needless to say, we’ve now gone, I think, many, many hundreds of miles, thousands of miles, away from the original concept, because now we’re not talking about actually bringing about energy efficient technologies that will permanently reduce demand, but now we’re starting to get into this kind of murky concept of paying people not to consume potentially at certain times. And then in Order 745, which as Speaker 1 said is what will bring about, potentially (pending the litigation), a greater use of demand response in the energy markets, you get the notion not only of this definition of “what people would have consumed otherwise,” you get this idea of “balancing at the margin,” which to me sounds more like an ancillary services product, as opposed to an energy or capacity product.

So what are we actually getting? And I picked on PJM to look at this because, to their credit, they have a lot of data, and in the most recent auction, clearly what’s now being called demand response tracks the definition in the 2006 staff report and tracks the definition that we’ve heard earlier. And there’s also “energy efficiency,” separately categorized by PJM, and I believe by most others--and notice that under the definition of “energy efficiency,” non-permanent measures don’t count. So I would submit negawatts equal energy efficiency, clearly, by the article and by the common definition that we’re now using, not demand response, but people can do both. They’re all offered in the market.

So we just had an auction last month. We know what occurred in that auction. Total demand response cleared was 12,408 megawatts. I think that’s rounded up one or two megawatts. Noticeably, it’s down, both in terms of how much was offered and how much was cleared, from the prior year auction, largely because PJM tried to actually get some definitional clarity by having some enhancements to what actually is demand response. It’s one thing to say, “comparability doesn’t mean equal,” but it’s a whole other thing to say that things are so far askew that three years forward you don't know what you're demand response is going to be. The demand response community opposed enhancements PJM proposed that would have established penalties, what you have to do to bid or not bid, and what you have to do to qualify. FERC decided they needed to go to a tariff process. But that decision came so close to the auction that the belief, as stated by the market monitor, that just the prospect that the demand response might face some definitional clarity and more certainty, resulted in the lower amount being offered, and the New York Independent Market Monitor said the same a couple of years ago with respect to New York rules. And the amount of energy efficiency negawatts, what I'm suggesting to you are the actual negawatts, was only 1,017 MWs.

So if you want to say, "Are we getting megawatts with demand response?" the answer is clearly no. It's interesting to talk about how much cleared on a megawatt basis or the claim that people are saving money. In fact, what the market monitor report found last December is that a large portion, over half of the demand response, over half that clears the base auction three years forward, actually ends up being bought back for cents on the dollar in intermediate auctions, and therefore a lot of that demand response, a lot of that money, doesn't go to anything. It goes to the people who bid in and buy back. This is not atypical. There's a new report, I believe, in New England, talking about shedding, and the same thing is happening--the percentage is lower, it's about a quarter, but it's still pretty high. This has led to concern from the market monitor and PJM for years, as well as now.

To its credit, PJM is saying, basically, that in PJM there are different products, and many of these products aren't year round. In fact, the vast majority are not. They're limited to either ten times at six hours each, or some are seasonal. So you're basically having somebody making a relatively low commitment of 60 hours, competing against a baseload nuclear plant, and being paid the same, which is obviously absurd.

Is this what Amory Lovins had in mind? This is a picture of an actual demand response resource in the state of Delaware. This is being aggregated such that dozens of these equal, I'm told, 60 megawatts, and this picture in the data comes not from us, but from the Delaware Department of Environmental Control. This kind of thing has led to the debate about dirty diesel, which I think people are relatively familiar with. We pushed very, very hard when Order 745 was pending at the Commission, and I personally spoke to each of the CEOs of the eastern RTOs and asked them for hard data on how much of this demand response is not really demand response at all, but actually another form of generation called "behind the meter." They told me they thought it was half, but they didn't know. The data was not collected prior to the policy decision being made. This has been exacerbated by the EPA rule that was mentioned earlier, because EPA is now allowing these generators, backup generators, to run on an emergency basis without complying with the hazardous air pollutant laws. Several of the states oppose that. There are now three different pieces of litigation at the DC Circuit, as well as behind the meter litigation on hold pending the Order 745 case.

The importance here is that the record evidence from Environmental Defense Fund, Analysis Group, MJ Bradley, and others is that this behind the meter generation, other demand response, is actually displacing cleaner generation.

The Rumford, and then more recently, the Maryland Stadium Authority case, shows that these baseline concerns are real. In Rumford, the paper mills normally ran all of their needs on backup generators. They instead turned the generators off and took power from the grid to create an artificially high baseline, and then got paid to do what they always had done. In a case just this week, and I commend FERC for pursuing these cases, the Maryland Stadium Authority at the Oriole Stadium was actually getting paid for two generators when only one could possibly work if called on, a backup generator. They also were told by their service provider to turn the lights on and other things on non-game days to artificially impact the baseline.

And with 15 seconds left, I'll simply say that in our view, this should be an energy-only product if it's in the capacity markets. It should truly be comparable with all the attributes here we can explore later. And we're not alone in raising these concerns.

Speaker 3.

Good afternoon everyone. As you'll see, at least for the purpose of my prepared remarks this afternoon, I have chickened out of the policy-level debates, and figure I'll stick strictly to the implementation details and really the math behind calculation of what both Speaker 1 and Speaker 2 have referred to as this customer baseline load.

Let me start out, if I could just with a sort of a brief summary of the mechanisms or the flavors by which demand response participates in the wholesale markets at PJM. What most people think of, I believe, when they hear demand response, is really the predominant mechanism by which demand participates in the wholesale markets in PJM, what we typically call demand response, or DR in PJM. It's that second column on the chart. And it is under the FERC Order 745, customers actually reducing their demand and then getting paid through the wholesale market based on the amount of their reduction. As Speaker 2 said (and by the way, as far as I can tell, your numbers were spot on), we have a significant amount of demand response clearing in our capacity market in order to participate in maintaining resource adequacy on into the future. And that really is the primary mechanism by which demand response in PJM receives its revenue at this point. And once committed as capacity, all of those resources are then required to respond when PJM declares an emergency condition and actually requests the reduction. So they all participate as emergency resources. They are also allowed to participate in the energy market and to offer into and be dispatched by PJM and be compensated for reductions in the energy markets. That really is the focus of the rest of my presentation -- how we measure the amount of reduction.

However, demand response can also participate in our ancillary services markets, as scheduling reserves, which is sort of the day ahead, 30 minute operating reserve product—there's not very much participation there at all. So I'm actually not going to talk much about that one as far as the measurement's concerned. But then there is much more significant participation in our synchronized reserve market, and also beginning to dip its toe in our regulation market as well, and I'll explain those when I get to the end of my slides.

Speaker 2 mentioned the participation of energy efficiency in the PJM capacity market, and that really is a capacity-only product. As Speaker 2 indicated, in order to offer in and clear energy efficiency in the capacity market, there must be permanent reduction in demand at an end use customer site. So there really is no energy market participation at that point. There is a permanent reduction in demand that gets compensated for a finite period of time in the capacity markets--eligible for up to four years of capacity compensation before that permanent reduction gets rolled into load forecasts, and therefore compensation would stop.

The third flavor, that I really won't hit too hard, but I feel compelled to bring it up, is something that we implemented rules for in PJM a couple of years ago called "price responsive demand." It was implemented prior to FERC issuance of Order 745, but it really was a recognition that in many of our retail jurisdictions there was, and continues to be, a significant amount of automated metering infrastructure, AMI, installation, combined with significant attention toward development of dynamic retail rates, so that with a combination of the infrastructure that's necessary, as well as the economic incentive, we felt that there was a good chance that at some point retail customers were actually going to be exposed to time varying retail prices that reflect wholesale market conditions, and therefore would actually have the incentive to adjust their consumption in response to those time varying retail rates. So we incorporated rules at the wholesale level, really to make sure that, number one, we had as much information as we could possibly get from an operational standpoint, so that we could anticipate and even utilize those reductions to set prices at the wholesale level, but also to ensure that as the retail regulatory authorities were going through their development of time varying retail rates and overseeing the investment and infrastructure that would allow for retail consumption adjustments, that there was coordination that occurred with what's necessary at the wholesale levels, so that we didn't have response at the retail level that was not corresponding to what was required and necessary at the wholesale level.

So we went through our stakeholder process for adopting those rules, and had them approved by FERC. As you might imagine, since FERC's issuance of 745, and the fact that retail customers can get paid to reduce, as opposed to just avoiding higher charges by consuming less, we have not seen any registration of price responsive demand in PJM as yet, but we're hoping it will come at some point in the future.

So, getting back to the main topic at hand here, which is demand response and how we actually calculate customer baseline loads, we come back to the fact that if you're going to pay somebody for not consuming, you must make a determination of what the customer would have done if they hadn't done what they did. So you must make a determination as to what the customer would have consumed if they had not opted to reduce their demand. And that's really the whole point of a customer baseline load.

Do you "measure" baseline load? That might be a little bit generous. I would not go as far as saying it is witchcraft or magic. But it is not quite measurement. You cannot put a meter someplace and actually measure the reduction. You have to do some sort of calculation, and some might even say estimation, of what a customer reduced, because, like I said, you have to establish some level that would have been consumed had the customer not taken action to reduce that demand. So PJM has had a CBL (customer baseline) methodology in place for some time, probably since the 2003/2004 timeframe. And in the past couple of years, we went through a significant exercise with an outside consultant to review many types of customer baseline load calculation methodologies to determine which one is the most accurate for the use in the PJM market.

And this is really sort of what represents that CBL methodology that we have today. Basically what happens is, we rely on the fact that an examination of recent consumption on similar days is reflective of what the customer would have consumed on a curtailment day absent a curtailment. So we have three different day types that we look at. There's weekdays, Saturdays, and then Sundays and holidays are lumped together. And what we basically do is go back and look at the highest four of the last five non-curtailment days, and look at the hourly load on those days, average them together, and that essentially sets the baseline for a curtailment day. The only additional thing that came out of the consultants' recommendations that we adopted and actually incorporated in the tariff as part of our 745 compliance filings was the addition of what we call a "same day adjustment," or a "symmetric additive adjustment." So on a curtailment day, once we go through the CBL calculation, we then take the CBL value for the couple of hours before the curtailment starts, and we look at the difference between the CBL and the actual load, before the curtailment starts, and then adjust the CBL by the difference, for the entire timeframe that the curtailment actually exists. So we do an additive adjustment to the CBL value to recognize any small difference in the demand immediately before the event took place. What we then do, and I believe this is unique to PJM, is we actually go through a fairly substantive calculation effort to determine how much error there is in the CBL calculation for a given customer. And we do that through a method we call RRMSE, which is the Relative Root Mean Squared Error calculation. Basically what this does is, it does a CBL calculation for a 60 day test period that obviously does not include any curtailment days. We calculate the CBL for those 60 days, and then go through a calculation as to how much that CBL value differed from the hourly load that was actually consumed. So we sort of do a backcast, if you will, using the CBL calculation, as to what the actual consumption would have been. And then we determine, using that RRMSE method, what the percentage error would have been, and in order to use the standard CBL method, that error has to fall into a category of being less than 20%. If it's less than 20%, then really that CBL value is what's used for that customer. And I'll go into, in a couple of slides, what happens if that criteria is not met.

Basically, again, we take the hourly loads for the 60 days for testing. We calculate the CBL, compare them to the actual load on those days and those hours. We take that difference, which is the error for each hour, and square it, do the average of that square, divide it by the average load for all those hours, and then that spits out that RRMSE error, and again, if that turns out to be less than 20%, then that's good to go for that customer. If not, then we have to adjust for and use something else.

So we do have an alternative CBL methodology that can be used as well. Actually, we have several different alternatives that can be used. So we run that RRMSE test for a given customer. We analyze that error, and if it's greater than 20%, then essentially what we do is, we look to develop an alternative CBL based on the patterns that come out of the differences, in other words, where that error actually showed up. It is a very case specific evaluation. And so it is looked at on a customer by customer basis. And again, the intention is to address those errors that are otherwise unexplained by the typical CBL calculation. And again, these are addressed on a customer by customer basis, to come up with what an alternative CBL might look like. If all that fails, if a customer's load is just so variable that it can't even really be predicted by any sort of standardized calculation, then we fall back one more step, and we utilize what we call a Max Base Load value. And that terminology actually comes out of the NAESB M&V (North American Energy Standards Board measurement and verification) requirements. But basically what we do is we go back for the historic consumption of a customer, very close to the actual curtailment day, and look for what the minimum load that customer consumed was, and that is considered to be the maximum base load for that customer. And then that maximum base load is then utilized essentially as a firm service level for that customer, and reductions are measured below that Max Base Load level. So the reduction is simply that Max Base Load, minus their actual consumption, and that's what it can be compensated for, economic demand reductions. So again, this is sort of a fallback, when all else fails, because --

Question: Why does it say you take the minimum load, when you are calculating the "Max Base Load?"

Speaker 3: It's the average of that minimum, and we call it the Max Base Load because it's utilities as the maximum quantity they can get compensated for. So the reduction below that is what they get compensated for. So the terminology is what it is. Like I said, we sort of adopted it from the NAESB standards.

This table just sort of gives you a breakdown as to what CBL methodologies are actually utilized by demand response providers in PJM. The significant majority that standard CBL with a symmetric additive adjustment. That's 71%. 16% have fallen back to that Max Base Load, because the consumption really is that volatile. We have another 8% that are really sites that don't have hourly metering, because they are residential-type programs that rely on direct load control, what we call DLC. So there is an independent study that's done as to how much reduction is typically achieved per customer, and then once the provider sends the signal to those customers, the credit they receive is basically that study value times the number of customers they have signed up. And they have to redo that study on a periodic basis to make sure that it stays up to date.

So between those three types, that's the vast majority of DR. And then there are some other slightly varying parameters around CBL values that can be calculated in order to handle those customers that don't fall under those typical categories.

Let me hit the two ancillary services very quickly. I mentioned synchronized reserves. Synchronized reserves are online resources that can respond to contingency events, like contingency loss of a generation resource. The measurement verification for demand response that provides synchronized reserves is really very straightforward. So the idea is, instead of ramping generation up to account for a loss of another generator, it's just as effective to ramp demand down in order to recover. And so all we do is take that metered amount of demand on the part of that customer at the time the event is initiated, and we measure the demand ten minutes after that event was initiated, and the amount of load drop is the amount of synchronized reserve that was provided. The only exception is that there are some cases where we have industrial customers, like steel mills, that have batch load processes. And if their batch load process happens to be off at the time we declare an event, they simply need to keep it off during the entire event, instead of allowing it to come back and on begin consuming again. So we do a batch load exemption for those types of resources.

And then the ancillary service of regulation is resources that follow an automatic signal from the RTO in order to account for very small changes in demand. Generators follow the regulation signal, and we measure that in direct output. Load is measured, as far as regulation performance, almost exactly the same way. We establish essentially a baseline level of consumption, and the load varies around that baseline in order to follow the regulation signal, just sort of in the opposite way a generator does. So, again, that's very straightforward to measure. Only a couple of megawatts right now of demand resources provide regulation, whereas we have several hundred megawatts of demand response providing synchronized reserves today. There is much more penetration in synch reserves than we have in regulation at this point.

So that's the end of the slides that I was going to cover as far as how we measure demand response in PJM. There is an appendix in the slides that goes into some more detail as to exactly how these calculations are done. So I will look forward to your questions and the discussion later this afternoon.

Question: I can understand the need for measurement and verification. That seems like a lot of work to do, and I just wonder what that does to the overall costs, or whether once you have these systems in place, it's fairly automated.

Speaker 3: Yes, it is a fairly automated system. We have built our load response system at PJM. So the customers really just need to feed us their load data prior to an event. And we choke through all the calculations as to what the CBL is. So it's a fairly automated process at this point.

Speaker 4.

Thank you for the opportunity to speak this afternoon. I'm going to take a slightly different perspective here. I'm going to speak from the angle of market design as an analyst, not as a policy maker. One of the lessons a policy analyst has to take home, if you want to have any impact on policy making, is to repeat yourself and to repeat and to repeat and to repeat.

So this was an issue that has been around for a decade or longer, as the previous speakers have already alluded to. So I don't have to give you a lot of background. What I'm doing here is really to synthesize some of the key elements. For those who have heard me talking about this, bear with me, and if I skip some of the obvious things, I can elaborate. The opinions here are entirely my own. Certainly I'm informed by the literature, by the writings of many, and also with the privilege of having access to my colleagues and so forth.

Now, the question here that is posted is, what is demand response? And I've struggled with how to answer this question. And in the end, I chose the topic of "demand response via voluntary demand subscription," because what I see now is that from the market design perspective, demand response is one component in the DNA of market design. What is the other component? It's a supply response. And the current wholesale market design is centered around supply response, and a central element of supply response is the central commitment and dispatch process.

So what is the counterpart of this central dispatch? Here I'd actually like to suggest voluntary demand subscription. And it is not something new. This concept has been around for more than two decades. Voluntary demand response does two things. One is, it provides genuine customer choice. But the other one is, it provides a legitimate customer baseline. And if it is done right, then I can fairly easily support many of the comments by previous speakers.

Now, if it is not done right, then I have questions.

I think it is worth taking a very quick look at history. I'll just point out a few key milestones here. PURPA is really the first event, and most people acknowledge that, in that it provides a path-breaking introduction of the marginal cost pricing concept into this industry. That puts the restructuring process in motion.

And then in the 1990s, the Energy Policy Act set the foundation for the later development of restructuring.

When it comes to the "negawatt revolution," I totally agree with how Speaker 2 characterized it. It has nothing to do with the demand response. But "negawatt" is a very nice package of demand side management ideas. Actually, at that time, that was sort of fairly innovative, and Lovins borrowed some ideas of emission trading and expected that all these energy savings could be packaged in a way, just like in an emissions trading market, so there is a market solution that can actually help subsidize or capitalize demand side innovation and new technologies. But later, this term, this concept has been used to capture the imagination, but it's not equivalent.

And then the painful event, the California crisis, which I characterize as why we are here. This crisis exposed something that we all learned very painfully. You need two hands to clap. And you need both supply side and demand side in order for a market to work, to perform efficiently.

And then in 2005, the Energy Policy Act provided a congressional mandate, in which demand response was a term that was used. But up to that point, I submit that demand response was an economic term, usually employed by the economists, and it was esoteric to a lot of business. Up to that point, demand response was considered to go in two directions. The response could go up, or it could go down. It was not just demand reduction. And demand reduction came about truly after 2005, with the DOE report and eventually with FERC Order 745, and we now actually call it demand response, even though we are only thinking about demand reduction. But originally, even when that 2005 Energy Policy Act was written, most folks were thinking about demand response as a two directional thing.

In the 2005 Energy Policy Act, the mandate was really to direct FERC to work with the states. It is not just a federal thing. This is a federal/state collaboration. And also the Act encourages the states to coordinate. So in order to fulfill this mandate, I submitted that the federal/state jurisdictional collaboration is the key, really, to put together a supply demand into the market.

Now, as to the way that this is implemented, FERC 745 is trying to reduce the barrier to demand response. So it clearly introduced the concept of a baseline. Now, when we talk about a product concept, it's OK to talk about whatever terms in English. But in the end, it is how it is measured. And it's like progress in science. You can make tremendous progress in physics by actually providing very concrete notion of how to measure mass, how to measure time, how to measure force. Otherwise those terms are just common English terms. And we can call demand response whatever we think, but at the end of the day, it is really about setting a baseline, because in order to measure demand response, everyone knows that it takes the difference between two numbers. You have to take the actual consumption and then take the baseline, and take the difference between the two. And the complexity here is that you take two numbers to measure a product. Most of the time when we buy and sell things, we only need one number. And these two numbers create all the complexities.

I had the privilege to have a conversation, a communication with Alfred Kahn during this process. I sent him a note, and I was puzzled about why there was a long pause without any response about this baseline issue. And it was tragic that during that summer he had a car accident and later, actually, he passed away. But before that he still finished his testimony for 745. But he left me with the words, “This issue is not going to be resolved that soon. You can count on that.” And his footnote actually says very clearly that if you want to evaluate the performance of this order, this is a very relevant issue, and “negawatt” here is also put in quotes. It’s certainly not equivalent to demand response.

Overall, what I take from this sort of historical review is that now we have two big elephants, wholesale and retail. And wholesale markets are really taking the leads. And retail markets, as I see it, are really lagging far behind.

How do we actually move forward? I want to go over very quickly the problem that we see with the baseline. What are the problems with the baseline? Everything relates to incentives when we actually design the market. Why do we want to reengineer all this least cost central dispatch if we already know how to do it well? The rationale for the FERC order was really to recognize that during the peak period there was overconsumption, because the marginal incentive for consumers is to respond to the retail rate, and the retail rate tends to be too low during the peak period. So there was overconsumption. If one can reduce that, one can actually bring about a lot of benefits in terms of reduced capacity requirements and other things.

If you actually want demand response to make some progress, you need to ask, what are the incentives for consumers, and how do consumers behave under any proposed scheme and the alternative baselines? And how well do we know how the whole market actually works? One has to take everything into account, in terms of equilibrium. It’s not a static thing. You have to incorporate consumer behavior into this.

Now, I want to point out two things. The consumers’ reaction to this can go too far in either direction—towards more or less consumption. I think the problem of potential customer baseline inflation is a well-known thing. There are numerous ways to inflate the baseline. Speaker 2 mentioned some of them. And the problem here is that during the peak period, what is already a too high level of consumption can be pushed even higher, and the colored sort of area (on the chart) shows what economists actually use to measure the social welfare gains or losses. So if customer baseline inflation increases overall consumption, there will be further welfare losses, those to the right.

And on the other hand, by paying consumers LMP and adding to that the fact that when customers reduce consumption, they don’t have to pay the retail rate, that can actually push the consumption too far to the left, so that it’s lower than would be optimal. So in other words, the right side (overconsumption) welfare losses can be replaced by the left side (underconsumption) losses, which could be much bigger. And a quick fix to this problem is that one can actually impose a minimum threshold price so that until the wholesale price is sufficiently high, you don’t invoke this demand response trigger.

This chart that compares alternative baseline designs (showing the change in social surplus associated with each) is also a summary of many of the ideas that have been talked about. The two left columns, I call "wholesale only" market design. This is close to what 745 is really about. And to the right, there are two more columns, which involve various degrees of collaboration on the demand side.

For the leftmost column called the "wholesale only 1.5," 1.5 refers to the minimum price threshold. That is, 1.5 times the retail rate, so in other words, the wholesale price has to be sufficiently high before this is triggered. The second "wholesale only" column is for a higher threshold, or 2.0. I will give you the reason why the 2.0 threshold warrants some consideration here. The 2.0 threshold is better than 1.5 for mitigating baseline inflation, in fact, because the 1.5 version is using the historical consumption level by the individuals to establish a baseline. We can see there are various ways that ISOs have been using various statistical techniques, like moving average or auto-regression to find this individual baseline. But the key here is that it's based on individual choice. And the 2.0 approach is based on aggregate choice. So, basically, you derive the individual baseline as a share of the aggregate baseline. It's like, if you measure energy efficiency, you use some industry standards, and actually compare individual or firms to that, and that's a way to look at energy efficiency. But here, similarly, you don't rely on individuals to say how efficient they are compared to what they did yesterday. And with the 2.0 design, the baseline is moved towards the aggregate baseline concept.

Now, the third column here (coordinated wholesale-retail) further incorporates the fact that there are two transactions, the retail side and the wholesale side, and unbundle the transactions, or you buy your baseline in some ways. And so that it corrects the exaggerated demand reduction incentive. However, that third column remains one-sided in its focus on demand reduction.

And the last column here, "Efficient market design," is based on demand subscription that restores the full efficiency of demand response, and that will provide consistent incentives. And that actually shows, really, the point of all this restructuring--if one can actually accomplish that incentive compatibility, there's a chance that marginal benefits and marginal cost can really be aligned. Remember, all this restructuring started by focusing on marginal cost. And here, we need the demand side to help with the equalization of the marginal benefit and the marginal cost. And that is really the foundation for all the service innovations in the future. The entire purpose of restructuring is to create that incentive for innovation. I think only the last column can accomplish that.

Now, for a policy analyst (and I apologize, I didn't actually lay out all the assumptions that actually is going into this comparison of alternative baseline designs. But this is based on the methodology I lay out in my 2010 electricity article, and later also in the 2011 *Journal of Regulatory Economics*. It's benchmarked to ISO New England's public data in 2007--the aggregate load, and use of demand elasticity of minus .2.) The qualitative insight is very robust. No matter what kind of methodology you put around it, a wholesale only baseline, with a 1.5 threshold, can be worse than the status quo. The status quo is to continue (without restructuring) the cost of service regulation, with average cost - based pricing. And then the next one, "wholesale only 2.0," after correction for some of these misaligned incentives using aggregated baseline, and with a sufficiently high threshold price, there could be a positive net benefit, but that is really so small that it is in the noise. The best one can do is to do no harm with the wholesale only solution.

And then the benefit begins to roll in once you have retail and wholesale coordinated in some way, even though it is not perfect. I think the benefit is twice as high for "efficient market design" as for the "coordinated wholesale-retail solution." And that doesn't count what I cannot count, which is the benefit of efficient service innovations.

Here is what I mean by a demand subscription program. Basically, it will let consumers choose. I think it's no different from a cell phone subscription program. The advantage is here, this is the first best case, is that really you get the two elephants (wholesale and retail) to join together in a lovely manner. Believe me.

And then, here, the coordinated solution lets them kind of dance to their tunes, but in some way that is coordinated. One thing I think I would like to emphasize here is that what we can do actually at this point, practically, is really to focus on cost causation principle. That is a good way, actually, to get into who actually pays for what and to sort it out in terms of incentives.

And also on the demand side, you can have it involved in the establishment of the customer baseline. It is inconceivable that the DR providers can actually negotiate with their demands, and then load serving entities have no idea what consumers actually are offering.

And what I want to leave here is that I think for policy makers, I believe, and I will suggest the most important lessons, is don't repeat. Don't make the same mistakes.

Moderator: Thank you. Any clarifying questions? So can I just clarify? So the efficient market design you mean is both sort of a rate design, like time of use pricing, plus some sort of fixed fee for cost of infrastructure? So that takes care of the flat fee, plus the energy use?

Speaker 4: I would say yes and no. I can understand where you're coming from here. I certainly agree with that direction. I think what is important here, what we learn from the wholesale market, is that what consumers buy today is a bundle. And if we actually begin to unbundle it, energy is an element in the bundle. And ancillary services is an element, which is more like a public good. And energy is a pure private good. And capacity is more ambiguous, the line between the two. And consumers today buy not only the megawatt, they also buy the option to consume any amount above that. And that is what we, on the other side, call the "obligation to serve," and on the other side even call it capacity options. Those things are also bundled right now. Now, if consumers have a choice, they can easily save their money, saying that, "If I don't actually buy that, I don't have to pay for it. If I don't pay for the capacity option, I don't have to pay for the capacity price. I can save my money." For large consumers, industrial consumers with a flat load, which consume most of their electricity during the off-peak period, I think they would love that option. And I think here it's important really just to open the gate here, and let them have a choice.

Moderator: Thank you. I hope you're repeating that often to legislators.

General discussion.

Question 1: My question, I guess, is for Speaker 2. It sounded like perhaps you were suggesting that it would be better to target particular things that you want to respond, and I wouldn't disagree with that. And I'm wondering what you see as the role of direct load controls in that respect?

Speaker 2: I think that's better than some of the definitions we've heard, but at the end of the day, from our perspective, this really is a retail program. So if a state wants to do that, then that's fine. And I think that's more real, if you will, and it avoids the baseline issues.

Question 2: I guess we take some exception to the notion that demand response is, a priori, a threat to the generation business, because we see it as a very important piece of clipping those peaks, particularly as you look at the market reform in ERCOT in the energy-only market. You know, generators see a lot of exposure when prices go to five, six, seven, $8,000. And this is a way to manage that. It's also a way to keep from overbuilding in a market, where you may not need that generation. We see that. But we do have, I think, some heartburn around behind the meter generation, which is just another form of generation from another source, not necessarily demand reduction. And I guess I'd be interested in comments from any of the panelists about how you reconcile what some companies like us see as these very valuable things, and problems with treating behind the meter generation as demand response?

Speaker 1: From the perspective of the wholesale market operator, or for that matter, if it's being done by a utility, the behind the meter generation, if it is truly behind the meter and is not pushing back power onto the grid (which only a small, small minority of them actually do), whether that generator fires up, or whether the customer shuts down a process, there's no difference. From the perspective of the system operator, they look exactly the same. The load is down either way. The fact that it was facilitated by behind the meter generation--there may be policy implications to that. There may be air quality impacts. But in terms of just how it looks to the system operator, they look the same. There's sort of a practical reason to allow it as well, and I guess I haven't been there, so I can't say whether that picture that Speaker 2 showed is typical. I suspect it is not. I've been in places where you could eat off the floors where these things sit, but that was not a particularly good example of behind the meter generation. But what it is, is sort of the gateway for customers to participate in demand response. By and large, most customers, if you go to a customer facility operator, boiler Bob, whose job is to make the facility run the way the people expect it to run, and you ask him, "What can you do in DR?" The first answer is almost always, "Nothing." You know? That's one of the reasons why aggregators are so valuable, is that it takes folks like us to go in and say, "Hey, well, we know people who are doing this, that and the other thing, and they have a facility just like yours." We can help find those things. But the simplest thing from a customer perspective is if they have a backup generator, and they can fire that up, that has no opportunity cost for them. And quite frequently we'll have people who get started with a backup generator who don't believe they can do anything, and then they move on into doing the load curtailment. So I mean, there's a practical reason for allowing it as well.

Speaker 2: Well, I think it sort of brings up the whole debate here about what is this that people are paying for? And it kind of goes to whether or not it's really going to be comparable to and a substitute for generation, which is what the premise is supposed to be. In that case, there has to be some kind of time connection to that. And so that's why one of the recommendations we had in the slide is to make sure that the capacity market payment isn't just to be paid so that they'll get a revenue stream to be in your program. It's supposed to be a payment to have resources available three years out, and even longer. And as Speaker 1 just admitted, these are not customers who are in the power business. They're in other businesses. They're going to come and go. And what we think is lacking in part is the fact that these folks get paid largely because they can use a backup generator. They hardly ever get called. And there's no must-offer obligation. And there was no refutation of the evidence in the docket that what's happening is that actual generation, both existing and new, is being displaced by paying somebody for only one year, three years out. And they may not show up the following year. And the fact that the amount that was cleared in the last auction went down, shows that even when you just have some basic requirements, like certifying that deliverability is there…and so I think one of the ways to fix this, again, assuming this is going to be in the wholesale markets, is to link the capacity market to the energy market, as they're doing in New England, so that you then get true comparability and substitutability.

The reason there isn't much participation in energy-only markets is because you have to pay so much to get them to participate in the energy market. That should, I think, ring loud and clear as an alarm bell—the fact that you're paying it to be available in the capacity market, but then when it comes to time to actually call on them, they have to be paid a high price. They don't have to must offer like everybody else, and then that high price is not allowed to be reflected in the LMP. It just kind of destroys the idea that it's really a substitute. Because it's not. It's just a revenue stream to sign people up as easily as possible, and that's all it is at the moment.

Speaker 1: So there are a couple of things there. This will get interesting. First of all, I suspect you will find, if you dig deeper, that the reason that the participation dropped in the last auction has a lot more to do with the fact that the prices plummeted than it does with the requirements which were ultimately rejected by FERC, but as you said, rejected so late that we all treated them as if they were requirements. I can only speak for ourselves, but those requirements had almost nothing to do with the change in our offer quantities. What changed was the fact that we don't offer in as price takers, and at a certain point it's not economic to deliver this. And when the price drops by half, it shouldn't be particularly surprising that you have a significant drop in participation. So that's the first thing.

Second of all, I think earlier you heard that 50% of the DR came from backup generators. We don't have great statistics, that's true, but PJM has started rectifying that, and other ISOs are doing the same thing. The number in PJM is less than 25%. And there's really no reason to believe that it's significantly more than that in any other market. They're not fundamentally different in terms of their design.

The capacity markets, at least in PJM, are primarily designed to make sure that the summer peaks are covered. We need generators there all the time, because we want to have the lights running all the time. But we don't need all the generators all the time. And so the capacity market is targeted both for generation in terms of how we measure it and how we penalize it, and for demand response at hitting those system peaks. So if demand response can cover those needle peaks at a fraction of the price of generation, which it can, obviously, because it's beating it in the auction, then I'm not sure what the difference is.

And finally, with the must offer requirement, the reason there's a must offer requirement for capacity resources in PJM is for market power reasons. DR cannot exercise market power. And so therefore it is not subject to any market power mitigation rules. If there were, then that might be one of the things. But I think the real reason for trying to impose must offer obligation on DR is simply that it will reduce the amount of DR, which if I were a generator, I would think was just in itself a good thing. But less DR means higher capacity prices. It doesn't surprise me that you guys would take the positions that you do.

Speaker: I know we could go on with, "Less filling," and "Tastes great," for hours, but two quick post scripts. The must offer requirement was found just and reasonable and necessary and approved by the Commission, so it's not something we cooked up. The second thing is, just this week the independent market monitor, Boston Pacific, in the Southwest Power Pool, said 98% of the demand response is distributed generation.

Question 3: I wanted to pursue this whole discussion about distributed generation. I agree with you, there should be better statistics. I'm not sure what the environmental consequences are. It could be worse. It could be better. You could argue it either way. There's quite a lot of study. But I'm just trying to figure it out conceptually. Say I'm a large industrial customer. I prefer to have my own backup capacity. I invest in it. I pay for it. I have it. If for some reason it fails, and I have to call on the system, and I want to opt out of what we'll call the social capacity market, just out of my own private capacity, and I'm willing to run the risk of either not having capacity if my backup doesn't function, or alternatively, paying whatever the marginal cost is of getting me whatever capacity there is, and of course, if there isn't any capacity available, I lose, I don't get anything… What's wrong with that? I'm choosing to have a private arrangement. I'm making the investment to do that, to opt out of the social system. And I'm willing to pay whatever consequences. What's the problem with that?

Speaker 2: There's no problem, or there's less of a problem, certainly, the way you described it. And we made it clear in the EPA rule making, for example, that if it's a true emergency, if superstorm Sandy, Heaven forbid, strikes the Mid-Atlantic again, or anywhere else, then these emergency generators, whether they're at hospitals or businesses that you described, should be able to run and not be subject to environmental rules. And to EPA's credit, they agreed with our argument, which will be disputed in the courts, because the rural coops are contesting it. But they agreed. In the original proposal, they had something along the lines of what Speaker 1 was saying about peak shaving, which would have let these backup generators operate as peak shaving units, even though the environmental profile is pretty nasty. And to EPA's credit, they took that out. So what you described is fine.

The question is kind of twofold. Instead of purchasing power, you could supply power to your hospital or your business yourself, just like you could grow your own food or do other things, and not purchase things from the market, you can do that. The question is, should you, then, be able to be paid for that and not comply with the same rules? Because effectively, what the aggregators are doing, whether it's EnerNOC or Converge or anybody else, is they're aggregating these smaller sources as power plants. And the argument they made is "Well, this person is busy doing other businesses." Well, that's what they're for. If they want to aggregate these and bid them in as a 400 or 500 megawatt equivalent, then the environmental rules should apply. They should have to register at NERC. Certainly their quantity should count for market power purposes. They might not have market power, but if their supply substitutes for generation, that should be taken into account. So those are all the policy implications of what you're saying. And all we're saying is, if they want to be a generator, then be a generator and comply with all the same rules.

Question 4: I have a question for Speaker 1, and it gets back to the question on the last panel which referred to how in Australia or something, where they have a $30,000 megawatt hour price, or $25,000, that you're only seeing a very small amount of DR, but yet in PJM and ISO New England, where there are capacity markets, you see significantly more. Have you been in both markets long enough to know? What fundamentally is causing that difference? Because that seems like it's a big financial incentive for customers to get off the system when prices are $25,000 a megawatt hour.

Speaker 1: You would think so, and I think there are a couple of pieces to the answer. One of them, I think, is that for anything other than the largest customers, who are sophisticated enough to participate on their own, it takes somebody whose job it is, like ours, to go out and aggregate these guys and get them interested and to hold their hands and to make it as simple as possible for them to participate. So I think an essential component to an effective demand response program is allowing aggregators to participate, because that's where most of it in the restructured markets comes from. So if you accept that as a given, what you have in Australia is, initially speaking, there's no way for us to get money to pay the customer. And that's the other thing--there's this big difference between customers getting a check and getting savings on their bill. You know, think about if you were boiler Bob, who's in charge of facilities for someplace. Normally your job is to make sure that everything works. Are you going to want to change anything for some demand response program that might screw up the lighting or the heat or whatever? Of course not. It's just a risk. But if you can hand them a check (and we used to actually do this, but it's too many people now, we can't do it, but we would hand them a check, and they would then hand it to their CFO), then now all of a sudden you're a hero. Instead of a cost item on the balance sheet, you're a plus item.

So being able to pay people is also critical. So you need a mechanism for being able to do that. And whether you pay them full LMP or LMP minus G, which is actually how it's going to work in Australia (there, we didn't have this big debate. When the prices are $12,000 you don't really need to get into whether or not you deduct the retail rate for most of these people). So being able to pay them is critical, and right now that doesn't exist. There's a rule change that was made last year. We're actually in the process of implementing it now. The Australian electric market operator is basing all of the functional rules and what not on PJM's rules (props to PJM), and that will allow us to pay those customers. We think that we'll be able to work with those kinds of prices.

But otherwise, in Australia, there are a lot of gentailers. They're generators and retailers. And they do exactly the same thing. A little bit of DR, like just enough to sort of hedge their needs and whatever, is great. Too much, to the extent that it actually as the effect of substantially lowering the wholesale price, not a good thing. And so you'll see there's a little bit of it going on, but not in a big way.

Question 5: I'd like to ask a question about what was not covered today. And just bear with me for a moment. I think we ran the gamut pretty well of a pro DR, benefits of DR, maybe some concerns about DR, the mechanics of how to do it that Speaker 3 covered, and Speaker 4 covered policy and alternative issues, which I think gave a very robust picture. But what was not covered was what happens from an operator's point of view. And the concerns I have about this is in two parts, as an operator. It's planning the system. And from a planning point of view, we have rules on when generation can be counted in for modeling towards a future, and when it would not be considered in there. We have NERC standards that have be applied and followed. We don't have such rules for DR right now. I mean, we have an allowance of what's cut in, but it's not the same rigor. And from an operations point of view, on measurement verification, I know that we could look back after the fact and see if it was delivered, and there are appropriate rules, and there are appropriate penalties if things aren't delivered. And I know the business people and the attorneys are all happy. But on the day it's 95 degrees, and we're seeing thermal overloads and stuff, the 90 days later remedy doesn't help us. And so what I'm looking for as an operator is real-time measurement verification, where I can actually do something if you're not delivering. And so this is just a question to all of you, do you see an ability to bring that into the equation and make that part of the whole conversation and the solution to how DR is utilized?

Speaker 3: From a system operator standpoint, that is one of the significant concerns that the penetration of demand response in the capacity market has caused us to have. There were statistics thrown around as far as what percentage of reserve margin now is represented by demand response in future years. We actually put some analysis out a couple of months ago estimating how often we're going to need to call on demand response in future delivery years, compared to history, given the level of the reserve margin that is being provided by demand response. How many times are we going to need it in order to meet the demand on peak days? And it's going to be more in the future than it has been in the past, that's for sure. I for one will be very interested to see what that does to future commitments of demand response, if and when the frequency it gets called increases. We've actually had experience in PJM in past decades, really, back when we had active load management, before we had a capacity market, where we had a significant decrease in the amount of committed demand response the following year after we called on demand response two to three times, or four times in a given summer. So we'll have to see what happens there.

But from the standpoint of enhancing demand response to become a more operational resource, that's really where we're headed, I think, from PJM's standpoint. It does not give our system operations folks very much comfort to know (given the percentage of reserves that are now represented by demand response), number one, that they need to declare an emergency to call on it, because as you get more frequent, like I said, that does not give the operators a warm and fuzzy feeling. We also have a discontinuity between what you would consider your traditional supply resources and then your emergency demand response, because we don't get what are really economic offers from a lot of the demand response today. And we'd like to ease that discontinuity by getting those economic offers from all the demand response resources as well, so we can continue to look at the economic dispatch stack right into demand response, rather than, again, having to sort of stop everything and declare an emergency and move into some different mode of operations, if you will.

So there are some significant things that we want to do in the future. But really, even as soon as this summer and next, we are working on enhancing the real time information that's available to our operators by requiring curtailment service providers to tell us in real time much more specifically how much demand response they have, and how much is already off on a day when we're anticipated to potentially get to emergency conditions, and therefore how much is still left in the tank? So the operators, as they progress through an operating day, would have that information and know, when they make the call, what they can expect with more detail. So there's much more to come, I think, with the evolving nature of demand response as an operational tool.

Speaker 4: If I may add, I think that you raise a seemingly very simple question, but I think that's one of the most complicated aspects of what we need to get into. Let me sort of go beyond sort of what Speaker 3 just said in terms of longer term. What I see is how they will change the whole design here. Number one, if demand response is done right, it will change the definition of many of the products. Capacity products will change in meaning. And energy probably would change that much.

The reason I say the capacity products will change is that today system planning is based on this one day in ten years sort of criteria. So bearing that in mind, if the market remains no change, basically, we take everyone as no DR, and we do the sort of traditional thing. But if (let me just call it "demand response" here, meaning a two directional demand response) we say consumers can subscribe to demand response in both ways--let's say I am a large industrial consumer, for example, with a two megawatt load, saying that this is what I subscribe, two megawatts. Now, say I have my backup generator and so on. I don't really need a backup. I don't need the ISO to back me up. I have my grid, and I take care of my own thing. So in that case, ISO is not responsible for that two megawatts of load in planning its own future. One day in ten years doesn't apply to that. So in that case we don't have a sort of public good, so that the responsibility for that segment of the load is lifted. However, that customer is still connected to the network, and what if that customer wants to consume more? There's an upside. When they need it, they have to come in and pay whatever the wholesale price will become at that time.

In other words, capacity products, as far as that customer is concerned, is a new thing, and the ISO needs to actually establish new procedures in some way in reconciling the remaining obligation for the other consumers. We still have to fulfill that obligation.

Let me give you another sense here. Subscription doesn't mean buying megawatts. Subscription also means that some consumers can say, "I don't need all this reliability. I can actually buy interruptible service. I can sell all this flexibility back to the ISO, when you can interrupt me any time you want." So that the quality of the product is changing. And what is the obligation for the ISO to provide capacity for that kind of customer? Or that kind of customer can provide capacity to the ISO in planning process. And how do we count that as a resource? And the other customers can actually have even more reliable service, and they might actually want to combine their own backup microgrid with the ISO, and have a different agreement with ISO. What that means is to provide the reliability and adequate resources. So I think in the planning process, as consumers have more choices, we'll see that the new contracts actually are going to proliferate in some way, I think the planning process has to adapt to that. So we need to think about how to migrate from where we are to this eventuality.

Speaker 1: It might come as a bit of surprise, but we actually are not opposed in principle to a lot of the initiatives that PJM's looking for, in terms of real time telemetry. Now, this is not speaking for all CSPs, but we have real time telemetry--near real time, every five minutes or so--with all of our customers, and we installed that at our cost, because during a dispatch, when we are obligated to deliver a particular amount, we want to see whether or not it's manifesting itself or not, so that we can get in touch with people and tell them, "Hey, get on the stick. We need you to respond." And so it's paid for itself in that. So we have real time visibility, and we would be happy, so long as everybody else had to do it as well, to provide real time visibility into that same kind of information to the ISO control rooms. You can go too far. We have by and large, at least until the prices improve, exited the DR business in New England, and a lot of it had to do with prices--and that was our first market, first and one of our largest. But a big part of the reason was the technical requirements that ISO New England imposed. They essentially had visibility, not down to the aggregate level, but all the way down to the customer meter, and the kind of regressive baseline that they use, it means that where we might have to provide PJM with hundreds of data points, ISO New England gets hundreds of thousands of data points, and if any one of them is wrong, we can be dinged for compliance purposes. So you can go too far, but there's certainly a way to provide operators with real time visibility into what the resource is doing.

We also recognize, and I think I said this in my presentation, that as DR becomes a bigger and bigger part of the resource mix, it cannot expect to be called the same amount of time as when it's 5% or as when it's 15%. So we understand that the resource is going to need to be called more often, and it's our job to make sure that we recruit enough customers, and we recruit more than what our obligation is, so that when some don't show up, or don't show up for as long as we want, we have others to take their places. It's our job to do that. We need to make sure that the ISOs have the proper incentives in place, so that there's no irrational exuberance. Right? I'm going to get every one of my customers to respond, and that's all I'm going to use. So we have no problem with that.

Some of the issues, though, that are proposed by PJM, which include potentially some sort of must offer requirement, we don't think is actually going to address PJM's problems. The fact is that the reason that a lot of customers can participate is because customer outage costs are in the tens of thousands of dollars. So if the customer doesn't know it's coming, and you take his power away, it costs on that order. Because these programs narrow down the circumstances under which it can be called, like an emergency, which presumably the system operators are doing their level best to avoid, the customers become confident enough that the requirements are going to be manageable enough that they will be willing to do it for whatever the levelized price of the capacity payment is, or potentially an energy payment. As it becomes sort of undefinable how often they're going to be called, the prices that they're going to need to see are going to start to approach those kind of value of lost load numbers. So, and $1,000, which is the current offer cap, might not meet it. It might not be sufficient to give customers the sense that they're not going to get called every other day. But if everybody bids at $999.99, then when the price hits that level, because you've got a shortage, you're going to get all however many thousands of megawatts of DR coming at once, which is exactly what the operators are trying to avoid, having it all come in at once. They want to see it sort of staged. So it's not at all clear to me that moving to an economic model is actually going to address that. There may be administrative ways of dealing with it that, you say, "You've got to have this much and this much time, this much, this much, this much." That might work just as well. But we understand we need more flexibility, and we're willing to provide it. There may be less DR as a result of that. But if that's what the system needs, then you know, it will be interesting to see, as there's going to be a feedback loop. As people get called more and more often, there will be maybe some reticence to participate. But as long as you get the penalties right, it will be our job to make sure that there's enough there to deliver.

Question 6: This is for Speaker 4. Looking at your graphs, if in fact you had generation behind the meter, wouldn't that demand curve be shifting instead of moving along? And wouldn't the same thing happen with demand response payments, if you could figure out how much of those demand response payments actually figure into retail rates? Aren't we talking more about a shift in the demand curve instead of moving along the same curve? And therefore taking care of the over and under consumption problem?

Speaker 4: You see that these demand supply curves are drawn as if they were original one, and I see that if we are moving on the demand curve. But in fact, what happened is that when you have an incentive, the way to really look at this is that the demand curve actually is shifted down by an amount that equals to LMP. That incentive actually creates a shift in the demand, so you actually are moving on a different plane, because you already have money in your pocket. And that's why it is labeled vertically. The incentive effect basically is like you are responding to a price, which equals to the sum of LMP plus retail rate. So there are many ways that you can cut it. And people say, basically, that it's like you sell what you didn't buy, and that ultimate effect is the same here. You're right.

So I think one thing is that as we hear all of this, to an economist, it is important to distinguish between what you are moving on a curve or whether you are actually shifting a curve. In other words, here, when we actually look at a situation incentive here, it's important to realize that we are not talking about a static condition that stays there. But the whole market, and the structure and what consumers see and what we see at ISO, are different. There is a lot of asymmetry here. If you really want to capture all of this, you can get into very complicated sort of math that truly captures this accurately. It is, I think, one of the difficulties for the economist to communicate all of this among themselves and also with policymakers.

I must say that actually the truth is more complicated than how it appears in a graph, because when you talk about sort of equilibrium, that means basically you capture all these chain of events. I sort of like to use an analogy here. I remember the first time I was asked by the board members, tell me, what is really some, why do we do all this? What is market design? And I said, an example here is that I have two friends, one is an engineer, and one an economist, and they have two families. The economist has two daughters, and the engineer has two sons. They're both twins. And on their birthday, they need to divide a cake. The cake is round in shape, and those two fathers, they have different solutions. The engineer is very sophisticated. He comes up with an elegant way to measure, to find the center of the circle and cut a straight line through the circle, through the center, and they actually go ahead, and they take that as a solution. And the economist doesn't have that kind of skill. And the economist actually finds a different solution, basically saying to one of the twins, "You take the knife," and then tell the other, "You make the first choice." You know, the solution is that they're both happy. So in the end, they have basically achieved the same result. The point here is that really you want consumers to make choices, to bring their value into the system--and the so called value of loss of load, the value of service, those are all sort of information that a market designer doesn't have. No one really has it. Only the consumers have it. And once those values are brought out through this process, then we actually can have a curve that we can count on. We pretend that we have all that information, but we don't. So I just thank you for that question. Only if there is a demand subscription, that I can understand. Now, without that, I don't know really what consumers are doing well. What is the curve they are moving on, that they are staying on? I have no idea.

LEE: Thank you. Would you like to respond?

Speaker 1: Very quickly, lest anybody be confused to the contrary, I don't want anything that I said to be construed as in any way supportive of the demand subscription idea that Speaker 4 was talking about. When I saw those two elephants at the end, I thought they were two generators dancing in happiness, because the likely outcome of that kind of approach, because it prohibits the participation of aggregators like us, would be very little demand response in the market. So if anything I said suggested to you that I thought that was a good idea, it isn't, and we don't think that's the best case solution. Certainly we don't, because we would not have any place in that world, and I suggest that means that would probably be a lot less DR.

Speaker 4: Actually, I think we can actually honestly have some disagreement here, because my view here, actually, you will love actually voluntary demand subscription, believe me.

Question 7: I guess part of my question was answered in the prior exchange. (I got lost in the economist and elephant one.) But what I struggle with is, there's growing interest, and certainly in California a huge interest, in seeing clean technologies like DR play a big role in meeting the operational challenges that I described in my presentation. But what I struggle with is, beyond the traditional peak shaving emergency DR program, what is the real vision all of us can get behind on how we see DR evolving? And what I struggle with is, as it becomes a bigger portion of the portfolio of the resource mix, as we discussed, that means we're going to be relying on it more. And we need to know it's there. The performance and visibility of it need to increase. And I totally get that traditional DR programs are largely industrial based, where once in a while you call on them. They shut down a process. It's a big deal. It costs a lot of money.

But is that really our future? It certainly can be a piece of it. But how do we see things like more seamless reductions along the lines of home area networks, or even in the commercial office buildings, where it could be something you could call on every day, and the customer doesn't even know? It doesn't impact their business. And if you get those kinds of programs, it probably means you get a little from a lot in terms of a lot of customers. And how does the baseline resource model fit with that? Or are we really talking about more what Speaker 4 is describing, more of just a price responsive resource that isn't paid for that service, but it has some sort of a dynamic retail rate, where it's advantageous to have that? So I would just be curious about your perspective on this, just in terms of the monitoring issue I raised, that if we are going to more smaller increments of multiple customers, what sort of challenges does that create for the resource model that you have?

Speaker 1: So I guess I would suggest that the answer is sort of all of the above. Just like there's a spectrum of resources on the generating side--you've got base load plants anchored by I guess hydro and nuclear at one end, and at the other end you've got peakers that only run for a few tens or hundreds of hours every year. And no rational planner would build a system based only on nuclear plants. Well, maybe if you're in France. Or on peakers. Right? I mean, the sensible thing is, you're going to have a mix of all of those things. And I think the same is true on the demand side.

To make it easy, let's just put the backup gens out of it. I mean, it really sort of complicates the argument. Whether they'll be there or not is going to be dependent on a lot of things, but certainly you can do it without them, and they need not be part of it. You just get less DR. Right? I hate being out here sort of always like trying to support these things that I really don't even personally agree on, except I do agree with the proposition that it's better to run a few of them to keep the lights on than to let the lights go out and run every one of them.

So putting that aside, I think you're going to continue to have a very short hour type of operations, meaning super peak needs. You're going to need ramping flexibility, like they do in California. To get that, you're going to need something that's basically transparent to the customer and seamless, and that you can do over and over and over again, every day. Right? You're going to face that graph (of peaking load) every day. The only way that's going to work is if the customers don't see it happening. So you're going to talk about commercial buildings and billing management systems being integrated and all this kind of stuff. You're going to talk about mass market customers with smart grid, or something like it, deployed in a bunch of smart appliances that are there doing their thing, and air conditioning. There will be room for all of that stuff. But if you want a lot of that seamless stuff, you've got to have some kind of a smart grid in infrastructure. You've got to have appliance manufacturers that are doing that stuff. Until that's there, you're kind of needing to work with what you've got right now, which is mostly industrial customers and mostly some direct load control types of programs. And that will mix in with the same mix that you have on the generation side.

Speaker 3: I actually agree with a lot of what Speaker 1 just said there about the future. There's going to be a mix of what has been traditionally thought of as demand response, and the more automatic set it and forget it kind of mass market type of applications as well, given the advancement of the technologies that we've seen. So I do think it's going to be a mix of resources. As far as the measurement of reductions in compliance and those types of things, given the potentially smaller nature of the end use customers that are involved, again, I think technology has come to a point where that's probably not as much of an issue as it used to be. Meters aren't that expensive, and they're getting cheaper all the time. The bugs are working their way out of the implementations that we've seen so far. So I agree with Speaker 4, even with alternative implementations of this price responsive demand, as PJM envisioned it, I do think there's still a role for aggregators, even in that type of scenario, and whether we rely on them to get us the data that we need in a form that we can actually accept it, or we don't really even need the data right away, because it's just a reduction in demand, because of the real-time price signal is being received, either way I think it will continue to work. So I would agree this sort of array of resource types participating is where we're headed.

Speaker 2: I may shock at least some people and agree largely with what I heard. And (this is me personally speaking now) I was almost going to have a slide at the end about going back to the future or back to the beginning. If you actually went back to what the original negawatt concept was, and particularly even to the leadership in California has shown on the issue, then you're actually getting something. Then you can actually say, "OK, we're going to need X number of megawatts," and let generators come in, let people that have ways of paying other people to install the latest technologies come in, and the whole premise of it was matching up the long time horizon. And I think where it breaks down is when you take more of a static view, they're only going to look year to year, which is where we drifted to in Order 745, and say we're just balancing things at the margin.

So yes, there's going to be a mix. It's going to be demand and supply, but it's almost like the supply part sort of gets this response, "Well, of course we're going to need supply." And that's kind of what happens in some of these conversations, and I'm not saying you did that. But then there's no discussion of, what is that going to take? I mean, everybody I the room knows. You have wholesale prices by and large in the organized markets that are half what they were. We know load growth is going to be basically flat to negative everywhere outside of Texas. We know from the earlier discussion and the duck back slide that you presented that the type of resources that are going to be needed, whether it's a mix of supply or demand, are going to be different than they are in the future. Yet I have yet to participate in a rule making or proceeding or discussion where there's a discussion of what's it going to take for that generation to stay online. the standard in the law is not, "how low can you go?" The standard in the law is "just and reasonable." And there hasn't been much discussion of how we make So the short answer is, yes, I agree, there's going to be a mix. If I were a policymaker and not representing one segment of the industry, I actually think there's a lot to be argued for the original megawatt concept, but we, at the end of the day, have to make sure it all works together, and pulling it together is where we haven't really focused much, and that's what we need to do.

Question 8: One of the discussion questions was, what is the baseline from which we derive the volume of demand response? We've seen a number of FERC enforcement cases on falsified baselines, and we know that it's difficult to verify. Speaker 3, obviously you talked about your relative root mean squared error system. But the most recent falsification issue was this Maryland Stadium Authority case. What I'm interested in knowing is, was this system in place at that time? Is it that your 60 day test period maybe can be gamed? And what are the ISOs really are doing to ensure, to the extent that we're relying more and more on demand response for reliability purposes, that we know it's really going to be there, and that it's not falsified? Because that is actually dragging, I think, the usefulness of this product through the mud. So there's a lot of bad being done in this area.

Speaker 3: The last part of your statement there threw me a little bit, about there's a lot of bad being done in this area. And maybe I misunderstood.

Questioner: Well, I mean, this talks about the controversy. I'm not saying there's a lot of wrongdoing, but there's a lot of bad implications, because people think it's not really reliable. So it's a bad image issue.

I'm not saying that it's a pervasive problem. Sorry.

Speaker 3: Right. So I guess to answer your direct question, which is, "What are we doing to make sure what we are measuring is actually being delivered?" the baseline calculation is a big part of it. But in the stadium example, if you would have just taken the baseline, it was the metered load values that were being used for the baseline. So the calculation itself was correct. It's just that the actions the customer was taking were inflating that baseline by virtue of inflating the metered loads themselves. So I think there's a lot of vigilance that's necessary, and it has to be along the lines of automated types of analysis with respect to the data that underlies both the baseline as well as the metered load value during a reduction. So we're going to have to continue to be creative about how, as the RTO (and also as the market monitor), how we analyze the data as we get it, because data's being submitted in order to justify payments for reductions, or to show compliance with emergency load reduction requests. And we need to look for these types of anomalies, and say, "Well, the load values you're giving me for the week or two before don't match, or don't comport with the load values for the 30 or 40 days before that." So we're going to have to continue to be creative about those kinds of things and continue to have automated ways of detecting anomalies like that in order to bring these things to the surface when they do occur. But to get to your last point, I do not think it is a pervasive problem. I think it's like other types of market gaming that have occurred in the past. I think there are probably a very small number of potentially bad actors that, when we do see it happen, potentially give the rest a bad name and make it seem like it's more pervasive than it really is. That's my opinion of what we see happening.

Speaker 4: I pretty much go along with that. I want to make a distinction about reliability. Now, there are generally two kinds of DR programs, economic and reliability programs. There isn't really so much a concern about reliability programs. The baseline for reliability DR is determined in a way that's different from economic DR. Because when the ISO needs to call on the reliability demand response, an ISO determines the timing, and there is a way that ISO has more reliable information in determining that. That's less vulnerable to manipulation. I think overall the problem is manageable for a number of reasons. I think that one is that in ISO New England, the program is about 10%, and we have reached a point of saturation. It's not likely to grow much further than that percentage. And two is that in market manipulation, it's different from financial sort of market manipulation. The difference here is that it's a physical asset. You can actually get at the data on a meter by meter basis, and you can be monitored. And also, there are various sort of imaginable ways to manipulate. If one consumer has multiple meters, we can pay attention to that, how they shift their load, in order to play the game. And to the extent that they have the motivation, and also they have no business purpose, I think usually what we see, as long as this manipulation as a concern is raised, consumers cooperate. We don't presume that people actually are trying to manipulate it. There are adverse incentives. That doesn't mean that people will always take advantage of that.

So it's a manageable problem. What I see here is that I think the correct incentive is important in several ways. You know, we can actually manage this in a more efficient way. For the ISO to manage this is one way. The question is, is this the best way? If there are aligned incentives, probably we don't need it. And what I see here is that truly the aggregator will have actually an important role when we do it right, because consumers actually will have a new thing to worry about. They will need to make decisions. Consumers will need to make choices. And this will create opportunity for services, because the consumers, they don't have the knowhow, the information, to really make a good decision. They will need help. And also, in order to make use of this very diverse set of resources in an efficient way, an aggregator will play a very important role. What I see here is that it's important that I think everyone has a stake in this to get an efficient market designed right. Both the generator and the load side, they both want an efficient market such that everyone gains in the end.

Question 9: As I've listened to this discussion, the reoccurring theme is that the problem with all this DR measurement is that you're dealing with what are fundamentally inefficient energy markets in the day ahead and real time. In contrast, if you have an energy market, day ahead and real time, where prices aren't mitigated, or at least substantially mitigated--in other words, where there's high price exposure, coupled with investment of technology--and in ERCOT, what is it now, 98% of load is settled in 15-minute increments with IDR and AMI meters? Then I think a lot of the measurement problem goes away. The compensation problem, with one exception, does. And you're creating what I consider demand response in a lot of different levels. You've got load serving entities that are introducing more and more peak shaving--there was a story in the paper today, the Morning News in Dallas, where a number of large retailers are offering free nights and weekends, in exchange for a higher price the rest of the week. You've got load serving entities, both public and private, that are investing in callable demand response. If your price signals are right, and if your exposure is correct, don't you create the incentives that that go a long way towards solving this problem, and mitigating all the other problems, like measurement? And again, this is irrespective of whether you need or want some kind of capacity mechanism. This is just getting the proper incentives that actually drive the behavior.

Speaker 2: I think there's a lot to be said for what you're contributing to this. If you go back to the debate at FERC over Order 745, including the technical conference and some other events, and the commentary, it was quite clear that the reason why they were pursuing this was because certain people were frustrated with the failure of states to adopt the kinds of incentives that you're talking about. And there was quite a bit of fairly heated discussion about that. So it's always seemed to me that this is where this belongs, at the retail level, where you could have those type of direct price signals, as opposed to trying to do it through the wholesale market, and that's what I always thought was the better answer. But that's not what happened. There was a frustration that most states have not gone the route of providing consumers with the kind of clarity on a real time basis that they should have.

Questioner: But at the risk of being a little hard on you, it starts off in the wholesale market. If you have enough risk that market participants need to mitigate, then whether it's a retail issue, per se, or not, you'd think that you'd create the proper incentives.

Speaker 2: I see what you're saying, and on one of the early slides, I said that we need to look at broader issues beyond demand response, because one of the things we're finding now is that the wholesale prices are not being allowed to reflect the fundamentals. So you've got a point, because wholesale is, needless to say, a big component of the retail price, although a declining percentage, in some of these markets, In New England, for example, generators are stuck with the bid in the morning, even though the gas price might go wildly higher by the time they're committed. So there's a whole long list of reasons why in the RTO markets we don't think that the wholesale price is reflecting the fundamentals.

So you're right, that's kind of the building block. My own thought would be, it's easier to do in a state like Texas or New York or California, where you have an alignment, obviously, between the retail and the wholesale market for the most part. I'm not necessarily an advocate for single state RTOs. We've always said they should be bigger. But if you're going to do it, say, in New England, I would think you would have to have all the New England states get together and be on the same page.

So you're right, the foundation is the wholesale market. Get it right. But then you'd have to have retail market design that would allow the ultimate consumer to see the signal. I'm not really an economist or an engineer, so I'm not sure what I would do with the cake (probably throw it against the wall or something). But if people know what their actual price is at any given moment, they're going to act the same way they do with anything else. Get the price right. Let people respond. You don't need all these calculations. You don't need all these, questions about what would they have done if they hadn't done what they did do? And so on and so forth. So I'm with you on the price idea. I just worry about it only being done at wholesale, when the retail priced doesn't reflect it.

Speaker 4: I'm with you, also. I just wanted to say that to get prices right, that's a reasonable first priority. One thing that is on top of many ISOs' priority lists in getting the prices right is to figure out how to get scarcity pricing done right. That is still an open issue. So I think what you suggest is that somebody indicates why that is so important. And I don't want to get into the details here. I think basically that is really how to get a demand side into the market in some way, or get us a best guess of what the right price ought to be.

Speaker 1: It ought to work. The incentives are right. And I'd add that there is DR in the market. EnerNOC is a demand response aggregator that doesn't want, for a variety of reasons, to be a load serving entity. But that's OK. I mean, maybe that's not a concern to other people. But there are load serving entities who operate in these markets. I mentioned Australia before. They have every incentive to do a significant amount of demand response. You would think they would. They have a robust retail market there. There's a lot of customer switching going on. But for some reason, it seems not to happen.

Questioner: Well, to be clear, you also have to allow loads to participate in the wholesale market, which is what I really meant to say in terms of the price exposure. That seems to be in ERCOT beginning to happen, whether it's public power entities or private retailers involved, judging on, judging by the press releases they're putting out, and activities where they're trying to sign up customers for X or Y.

Speaker 1: So maybe it will happen in Texas first, because I think you have the ability to make it happen quicker, and there are fewer technical requirements. But if not there, then in Australia, there will be an ability and an energy-only market for people who aren't load serving entities to take customers and offer them into the market and get paid, so that somebody like us, who doesn't want to be an LSE and can't reach arrangements with one that does, can participate. And then I guess that will be a new thing, and I guess we'll see whether that new thing actually works, if we have the ability to sell into a market. And you'll have the other key, which is that you'll actually have prices that are high enough and close enough to sort of value of lost load that they may be able to do it. I'm personally maybe a little bit skeptical, but I'm working pretty hard on this Australian thing, so I'm hoping I'm not doing it for no reason. Thanks.

Question 10: Speaker 1, I've been listening closely, and I think I understand everything you've been saying, except for one thing, which I am puzzled by, which is your response to the subscription service idea. And it seems to me that, although it's not exactly the same, it is very close to buying the baseline, in other words, paying for the baseline, and that's very close to the LMP minus G debate. And you said the LMP minus G debate was not a make or break story for you, and certainly in Australia, you said it wouldn't be a big problem there, and all these kinds of things, when prices get really high. So could you give me the next two sentences about why you think subscription service would foreclose your market?

Speaker 1: I'm not sure if I fully understand the subscription service, but in my mind I was equating it to the buy your baseline thing, which I know you and others talked about in the 745 case. And the problem is that somebody has to actually buy the baseline. So that means that they need to be a load serving entity, or a customer who's participating directly in the market. And so it goes back to my previous statement that most of the DR that's been brought into the market has been brought in by aggregators, most of whom are not load serving entities. So the Constellations of the world could do it. Maybe the GDFs, if they were inclined, could do it, because they have the ability to buy the baseline, because they're participating. But there's really no way for an EnerNOC or a Converge or Energy Curtailment Specialists, or any of the other people who are largely responsible for most of the DR out there. That's our job. We know how to work with them in ways that I don't think retailers are particularly interested in doing, or particularly well suited to know how to do. So if we can't do it, then I don't think it's going to work very well. And if aggregators who don't want to be LLCs can't do it, there's going to be a lot less of it. So that's a lot more than two sentences, but does it answer your question as to why we don't think a subscription or buy your baseline thing would work?

Questioner: Well, maybe we can talk this later over drinks. But I think the customer can de facto buy the baseline, and that's what de facto what happens with the LMP minus G kind of story. And then you can provide the service, and you can get paid, and you can do all the kinds of things that you're talking about.

Speaker 1: So the customer can do that, but then this is back to the difference between the value --

Questioner: There has to be a baseline now.

Speaker 1: Well, this is maybe more a psychological thing that anything else. It means more to me to get a check for $10 than it is for somebody to take $10 off my bill. I mean, you're an economist. You don't see the difference, maybe.

Questioner: I understand why it's worth more to get a check for $10 than it is to get a check for $8. But that's what I'm talking about here. So you get a check for $8. And you can still be in business, and you can do all this kind of thing. I'm not taking the whole $10 away. So buying the baseline is not taking away, it's taking away two bucks.

Speaker 1: No, but for me to make money, they would have to pay me. Let's talk about it over drinks.

Questioner: You give them a check. You just give him as big a check. [LAUGHTER] I'm trying to sort out how to --

Speaker 1: Where do I get the money from? Who pays me?

Comment: You talked about the $10 in their hand, yet Reliant, in a recent workshop (and they like a number of load serving entities have been experimenting with what engages their customers), said that what they found is that offering a volumetric rate, in Reliant's case, with all their different programs, time of use and various others, the one that got the most attention from customers is the one that paid them 30 cents. Now, on an actual basis, that's probably less money than a $60 a year or $10 a month capacity payment to the residential customer. Yet it was that difference between what they're paying, which might be eight cents or nine cents a kilowatt, and the 30 cents, that actually got the customer's attention, I think, because they can sit there and go, "Oh, I'm paying X, and they're going to pay me Y, and that's a big spread." And I'm a buyer at that point, or a seller.

Session Three. Market Manipulation post *Hunter vs. FERC*

Does the decision of the D.C. Circuit Court of Appeals in Hunter vs. FERC change the landscape of market abuse enforcement? While the Court did rule clearly that FERC's jurisdiction is limited to physical markets and not derivative markets where the CFTC is empowered with regulatory oversight, the case pertained to allegations of manipulation of natural gas, not the electricity market. There is considerable opinion that the Court would have ruled similarly had it been dealing with electricity, but we cannot know that with certainty. We also do not know exactly what the CFTC will do with its powers, and there is some fear that the split jurisdiction inherent in the Court's decision may lead to less, not more, clarity in market abuse cases. That could easily happen if the two agencies went off in dissimilar directions. Even if they were finally able to come up with a common approach in the regional MOU, the statute has contradictory and confusing elements. In fact, the decision provides very little, if any clarity, on how the two agencies will act going forward. Numerous issues flow out of Hunter: What will the two agencies do? What would an MOU between them look like if they were able to negotiate one? What would enforcement look like in a world where one agency oversees physical markets while another regulates derivatives? Is such a jurisdictional split capable of producing a coherent regime, and how much will a ruling in natural gas impact electricity markets.

Speaker 1.

For some time, I have had in mind the idea of creating a way of thinking about market manipulation in a manner that's logically consistent. Not just consistent across cases, but consistent across agencies, consistent across statutes, and now that EEU has adopted similar anti-manipulation rules, similar across continents. So what I'm going to talk about first here today is the idea of what I call a framework for the analysis of market manipulation. And the idea is just to come up with a common way to think about these things, whether the FERC has jurisdiction over the case, or the CFTC has jurisdiction over the case. Ideally, if the statutes are all identical--and most of them really are, because they're all based on the SEC's rule 10b-5--what we could hope for is that we would get a common structure of analysis, irrespective of where these cases are tried.

So, basically, one of the biggest problems in market manipulation is simply trying to ascertain cause and effect. And part of the reason for that is our training in economics tells us that markets are efficient. So a lot of times, we'll begin with the assumption, hey, markets are efficient. So if markets are efficient, traders are just looking at prices, looking for opportunities to make money based on what they see. They see, perhaps, something that provides an opportunity, and they go into that market and they buy or they sell, based on whatever their native strategy is. Let's say they sell. Let's say they sell everything they have. Say the price starts to go down. Other people start to sell. This starts to create a cascading effect. The price falls, falls, falls, falls. And the trader has the ability to say, "Look, I thought the price was going to fall, and by golly, I was right. Notice that I sold my product, I got the best price I could at the time." There's nothing that was outside of the efficient execution of the bid stack order, no problem there. Bid and order stack. What you're left with in that case is since every sale tends to push prices down, and since every purchase tends to push prices up, you simply are left with the argument that the trader really had no effect on the marketplace. If they did have an effect on the marketplace, well, that's the market's fault for not having sufficient liquidity to prop up these trades. That's why we want more competition. That's why we want more liquidity.

Those are all certainly valid arguments. But the fact of the matter is, as we know in electricity and energy markets in general, the requisite assumptions for a competitive market are not always there. And whether that's one percent of the time, two percent of the time, whatever, during those times, what you see is that traders have opportunities to behave in a different manner. Specifically, traders can see that the volume that they put into the market, either in the buy side or the sell side, can have an effect of biasing prices in a direction that favors them. The price movement will injure them on a standalone basis, but it will benefit some other position that is tied to the price that they are moving.

And that's really what we're going to talk about mostly today, or at least what I'm going to talk about most of the day, is this concept of uneconomic trading, traders who are losing money in one position in order to make more money in something that's tied to that price. So the one thing that we would really like to have from this, though, is something that's cogent, and more importantly, I hear this from traders all the time, we need to come up with something that has the ability to define what is legitimate trading, as well as what manipulative trading would look like.

And so my goal here is to try to come up with a clarifying framework that gives us that definition. If you fail to provide that definition, lots of bad things happen. First off, you start to see traders just simply throw their hands up and say, "I'm not going to trade anymore." And we're seeing this in several markets. In California, the liquidity has dried up, it's 80% of what it once was. When you have unclear rules, you have traders who simply will say, "I don't want to mess with this. I don't want to trade financial instruments while I'm trading my physical portfolio, because that's going to get me in big trouble. I'm just not going to do it anymore." Well, that's horrible because they're not allowing themselves the benefits of the financial markets that were designed to assist them to help them hedge transactions. Likewise, as you see people pull out of these markets, the liquidity goes away. Once the liquidity goes away, that just makes the markets that much easier to game. So clear rules would help with these problems.

The other problem with unclear rules comes from an enforcement perspective. Basically, if you have agencies that don't have a clear path to what they are prosecuting, there's the potential for false positives, the potential that people will be investigated for acts that were completely legitimate, but for which whatever particular activities passed through or failed the agency's screens will put them on the radar map for an investigation. As those of you who have been through the process know, an investigation is a very one-sided affair. The agency will get in contact with you. They want your trading records. They're going to want to depose you. Even having the reputation of having been investigated is a horrible, horrible pain for a trader to go through. It can prevent them from getting jobs. So by having a more clear way of thinking about this stuff, perhaps we can vet and prevent those false positives as well.

My last point is actually quite important. What I'm trying to put out here is actually a way of thinking about manipulation that's consistent with existing theory of competition law, antitrust, as well as existing theories of fraud, such as the prosecutions by the SEC for things like banging the close or pump and dump schemes. So this is going to fit within those structures.

All right. Let's focus on the types of behavior that can cause market manipulation. And mind you, I'm not trying to be all encompassing here, but from my perspective, uneconomic trading, outright fraud, and the exercise of market power are the big three that I see across the various manipulation cases by the various agencies.

The hot topic these days is uneconomic trading, intentionally losing money in one position to make money in something else that's tied to that position's value. We see there are four cases up there. The first four are FERC cases. I've got Amaranth and Deutsche Bank both highlighted because I plan on talking a little bit more in depth on both of those cases. But all of the first four involve uneconomic trading by a trader to manipulate the value of swaps, index positions or something else that is tied to the price.

Comment: Alleged.

Speaker 1: Alleged, yes. And as a matter of fact, none of those cases has come to a conclusion, other than a settlement, or in the case of Amaranth and Brian Hunter, I guess it's de novo. Has the statute of limitations run for the CFTC to go after Brian Hunter?

Comment: There's a lawsuit that's pending.

Speaker 1: OK. So that case is going to continue to be in the pipe. The next two cases, *DiPlacido* and *Optiver*, are actually CFTC cases. And those have come to a conclusion. DiPlacido was an energy trader who was trading swaps that were CFTC jurisdictional. *Optiver* is actually a "banging the close" case. It's a Dutch company that was trading NYMEX futures contracts. They would buy options that were typically short to the end of day price. They had a program that their traders would execute called The Hammer. (Yes, I know). Make it to the end of the day, The Hammer would execute, and would lower the price of the NYMEX oil contract to the benefit of their short derivatives position. So these are all examples of uneconomic trading, banging the close just being one specific case.

The Department of Justice has actually gotten into the market manipulation game as well. The KeySpan-Ravenswood case was originally before the FERC. The FERC passed on it because it said, "Hey, we're really not capable of talking to these issues." So it went to the Department of Justice, which ruled that an act of withholding worked as a market manipulation in affecting the value of a swap. So here we see that market power can be used to trigger a manipulation as well.

Then, from the standpoint of outright fraud, I think we have ample evidence of cases where people have put false reports into the marketplace just to get market actors to act on that misinformation. That's caused some price movement that benefited the derivatives.

So those are the three types of behavior that I would say could trigger a manipulation. Again, the framework we come up with has got to be consistent and able to take account of all three of these different types of activities.

So let's talk about the framework. All right. I think about the market as this giant machine that has millions, maybe thousands of things that are inputting at any given time, making the machine move toward doing its wonderful business. The fact is, however, there are levers that are tied to that machine and if you push one of those levers, the machine tends to work a particular direction. Likewise, there are instruments, derivatives, "at index" physical positions, that are tied to the machine and whose value depend on that machine's movements. If the machine moves one way, the pile of money gets bigger. If it moves the other way, the pile of money gets smaller. There are linkages to this machine between these levers, which I'm going to refer to as the "triggers" of the manipulation, and these piles of money which are the manipulation's "targets." When constraints bind, there are fewer forces acting on the machine, and there's much more causal linkage between the trigger, the lever that's being used to make the machine move, and the pile of money, AKA the target, that's affected by that movement.

So when you think about a manipulation, we want to separate the cause and effect. The cause of the manipulation is its trigger, that movement of the lever that makes the machine move. The target of the manipulation is the manipulation's effect, usually one or more price-taking positions that form the pile of money that gets larger if the manipulation's successful. And then, finally, there's the nexus of the manipulation is whatever mechanism is being moved in the machine that's providing the causal linkage between the trigger and the target. So when we think about the framework, it really always will have these three pieces.

Typically, the trigger will be price-making trades, trades that go into the market that set a price. What are some things that could set a price? Well, just fall back on your normal microeconomic thinking. An exercise in market power can move a price. We know that. An act of withholding, where, say, a monopolist will withhold output, can drive price up the demand curve. And likewise, a monopsonist can drive price down. Outright fraud can cause a price movement. If I put a false storage report into the market saying there's a lot more gas out there than people think, people will sell off believing in that report, and as a result, I can trade at a lower price.

Finally, there can be acts of uneconomic trading, intentionally losing money in a position for the purpose of moving or biasing some market outcome. So if I want to go into the market and I want to intentionally lose money on a sale, I can push a price lower than it would be in a competitive process. That can benefit my position. So I'm going to give you an example here in a moment.

But just to go through the other two legs of the framework, targets are anything that can take the price that has been manipulated. So what are some things that can be affected by the price? Physical positions that are traded at index. When that index resolves, those positions' values are set. Derivatives positions, which have the benefit of being self-liquidating on top of everything else. And then, there could be other positions, such as reputation, or things that we're not necessarily aware of. Say, for example, you have an electric generator who has a fleet that they're actually thinking of selling off at some future date. If somehow that seller can manipulate prices up, especially on the forward curve, they can increase the present value of their fleet and thus garner a potentially higher price for a sale. That's kind of an out there example.

So when you think about, finally, the nexus of this machine, what makes it work, the nexus is any relationship between a triggering price and something that takes that price. So it could be an index. It could be an auction mechanism. It could be an end-of-day mark price. It could be a spot price during the course of the day. Any price that can act as a reference price for a potential target could be a source of a manipulation.

Now, before I go on, let me just give you an example, and I apologize for those of you who have heard this probably more than once, but I like to call it the condo example. And I like it because it's pretty straightforward, and it uses something that everybody's familiar with, which is real estate. Let's come up with a hypothetical world. I own a condo in downtown DC. It's worth $500,000. The reason I know it's worth $500,000 is because there's a price index online called Zillow. All Zillow does is just look at the last 30 days comparable trades and just takes a straight line average of those trades. If you look on there right now, there are 19 trades on the index, all tightly packed right around $500,000. Now, let's assume everybody in the market looks at that index and says, "Yeah, that's what the price is," both buyers and sellers. Say there are hundreds of condos just exactly like mine for sale, all throughout Washington, DC. So let me ask you, if I go into that market and I offer my condo for $800,000, how much luck am I going to have selling it? None. Why? The reason why is because I have no market power. I have no ability to raise my price above the market price, because there's nothing special about my condo. There's nothing special about my sale. I have no ability to benefit myself on a standalone basis by raising my price above market. By comparison, now let's say I sell my condo for $100,000. How much luck will I have? I'm going to lose $400,000 relative to my opportunity cost. So I'm giving up $400,000 of profit from the market that I could have made. But the buyer gets that money back. So it's a zero sum transaction, right? Who cares?

Notice the effect that that sale now has on the index. Now there are 20 trades on the index. That 20th trade, which I put on there, lowered the index average from $500,000 to $480,000. So with five percent market share, one uneconomic trade was able to buy us the price making mechanism to lower the market price by $20,000. Now, before I talk about why I would do this, first off, realize the harm that was potentially created by this. Everybody in DC who owns a condo has just lost $20,000 of value. It's an unrealized loss, but the fact is, if they were to go out tomorrow and to try to get a home equity loan after I've done this, they just lost $20,000 of wealth that they can't borrow against now. So there's a very real effect of this all throughout the marketplace. Why would I do such a dastardly thing? Now, I go into the market as a price taker and I buy 50 condos. Remember, there's hundreds of them for sale, so there's no scarcity pricing that comes in. I'm going to buy 50 condos, saving myself $20,000 each. I save a million dollars by losing $400,000 on my initial trade. So with five percent market share in the price-making market, I moved the price enough to benefit my ultimate manipulation, which was accrued through the purchase of 50 condos, netting $600,000.

A lot of people might have problems with that example for lots and lots of reasons. For example, real estate is not homogenous. Every piece of real estate is unique. We know that people don't rely in real estate so heavily on an index. There's also a problem from the standpoint of how am I going to cash in my money from all these condos that I bought? I'm going to have to eventually sell them. Maybe when I sell them, the price will be even lower. Who knows? These differences go away when we start to think about our gas markets and our electricity markets, where we do have large physical index trades that are based upon an index that resolves during a short period of time, as well as derivatives that are self-liquidating that are tied to those same prices. So the example was just designed to be relational from the standpoint of condominiums because I think most of us easily understand real estate. Its application applies very directly to our commodities markets, energy in particular.

So the idea behind thinking about a manipulation like this is to say, "Well, OK, in the condo example, what's the trigger, what's the target, what's the nexus?" It's really pretty simple. The trigger was the one uneconomic trade that I put into the marketplace to bias the market price. The target of the manipulation is the 50 condos that I ultimately bought that I was going to save money on for every condo that I purchased. The nexus was this price index that existed online.

If we were to try to generalize this for all of the different types of triggers and all of the different types of targets, what you get is a diagram that I show up here as being somewhat circular. And I draw this as a circular diagram for two reasons. Number one is that this is a source of some of the confusion that often accompanies market manipulation cases, because cause and effect essentially are circular. Instead of saying, "the trader executed a trigger in order to benefit a target," somebody could just as easily say, "Hey, I was just seeing something that was happening in the marketplace relative to my targets, that prompted me to act on the trigger." So the same logic is--I don't want to say twisted because that may have a negative denotation--to say "Hey, all I know is the trader was just looking at prices. Whatever they did that you're calling a trigger, that was just good trading. Did they make money on it? Sure. See how much profit they made on it."

I think it's better to unravel that. I think it's better to start with the idea of looking at the trigger first. Look at the price-making trades first. Ask yourself the question, did the trader do something that was intentionally uneconomic? Did he or she do something that was outright fraud? Did he or she do something that involved the abuse of market power? If the answer to any of those three questions is yes, you need to keep thinking about what's going on. If the answers are no, no, no, then that trade was legitimate. There's no reason to think of it as manipulative, because it's not uneconomic, it's not fraudulent, and it doesn't represent an abuse of market power. But let's say the answer to one of those three questions is yes. Well, now you have to think, "All right, well then what effect did that price-making trade have?" You go to the nexus and you say, "OK, is there some causative linkage that ties that act, that trigger, to some target?" Now you have to start looking at the targeted positions and start saying, "OK, what was there to benefit from this price movement that was created by the trigger?" We've already talked about what those targets could be--financial derivatives, physical positions at index, other cross market positions that could be there as well. Ultimately, if that nexus is a true causal link and you do find sufficient evidence of a trigger and a target, you're going to wind up seeing also that this manipulation threw off profit.

It's very important to note the level of profit relative to the manipulation trigger. So, specifically, if you're losing money in the trigger, it would only make sense for you to do this if you make more than that amount of money after you cycle through and get profit from the target. So for example, if I lose a million dollars in my economic trigger, if I get back $800,000 through my target, that's not a manipulation target. We've got another name for that. It's called a hedge. The fact is, if you are making back money out of your target and it is insufficient to cover your losses on whatever you did in the trigger, that target is actually a hedge transaction. That's perfectly legal. That's why financial markets exist. Likewise if it's a one-to-one relationship, you lose a million, and you make back a million. That's a perfect hedge. The only time you are really worried about this being manipulative is if you see that the amount of leverage in the target relative to the trigger starts to go greatly above one. 1.1, 1.5, 2, 3, 5 times. If you're losing a million dollars and you make back $5 million on your "hedges," the agency is much less likely to view that as a hedge, and much more likely to view it as a spec position that you were using as a target for the manipulation.

So here are three things that make the manipulation more likely to be successful. The most important of these that we haven't talked about is that third bullet point, the elasticity of supply and demand. The fact of the matter is, we all know that as constraints bind, it's much easier to create price effects. As demand and supply become more inelastic, what that gives a trader the greater ability to do is create a large price effect with a relatively small price-taking volume effort bid. Deutsche Bank was an example of this, and we can talk more about that later if anybody wants to.

So to conclude, I give you this diagram. Generally, everybody I've put this in front of has hated it in one way or another. But the idea behind this is to take the framework concept and to apply it to different market manipulation cases. If you were trying to defend a trader against a claim of market manipulation, this might be a way that you would think about doing it. For example, ask yourself the question, "Was the trigger in question uneconomic? Was it the exercise of market power? Was it outright fraudulent?" If the answer is no, no, no, that trade is legitimate, there's no manipulation. But let's say the answer to one of those questions is yes or maybe. Well, now go to the second step. Ask yourself, "Did the manipulator have enough leverage in the target to make the manipulation profitable?" If the answer is no, well, then the target is a hedge, and there's no manipulation. If, however, you do have a leverage target, then you ask the final question, "Is there a causal linkage such that the manipulator knew that the trigger would affect the target?" A lot of times you need objective evidence of intent to show the linkage through this thing, in other words, the emails that say, "Oh, look at me, I'm banging the close," or people who are naming their schemes, things like Deathstar, Get Shorty… The fact of the matter is that objective evidence is almost always used in these cases to bolster what the economic evidence has shown. If you can go through all three of these steps and you still have a problem, your trader might want to think about self-reporting, because there is legitimate concern for manipulative activity.

What I basically did, from the jurisdictional standpoint, between *Hunter*, the Amaranth case and other FERC cases, between the FERC and the CFTC, is if you look at Amaranth and you really think about that result and that outcome, what it tells us, or what it tells me, is that agency jurisdiction is ultimately going to run with the elements of the framework. So if you think about, for example, the Amaranth case, what was alleged to be the trigger? Trading of NYMEX NG futures contracts. What was the nexus of the manipulation? It was the settlement of those contracts. What was the target of the manipulation? Derivatives positions that were short the price of that settlement. The fact of the matter is that the trigger, the target, and the nexus, all of three of these components, are all CFTC jurisdictional. No question. So the reason the FERC didn't get jurisdiction in this case, despite the end connection with language in the Natural Gas Act, is because they weren't able to prove that the CFTC should be dislodged from its absolute jurisdiction over these three instruments.

If you compare that to Deutsche Bank, all three legs of Deutsche Bank fall in the FERC's jurisdiction. The alleged power trade from Silver Peak to Summit, the physical power flow, that's FERC jurisdictional. The nexus was the California ISO's Market Option Model. The target was the CRR (congestion revenue rights) position allegedly held by Deutsche Bank that would benefit from this. All three components are FERC jurisdictional, no question there.

The problem is when you get some hybrid case, where either the triggers or the targets or the processes fall within different agencies' jurisdictions, or, as we were discussing yesterday, they may fall within nobody's jurisdiction. It may be some target or trigger that's outside the jurisdiction of either commission. What do you do there? The example I've got in this case is a target that's clearly CFTC jurisdictional. They're agency basis swaps. They tie to two prices that resolve, one through the CFTC's clearing mechanism, the other through a FERC jurisdictional index. Who gets jurisdiction over that case? Well, that is an open question I realize, and I'm sure that's something that we can talk about further.

Question: Speaker 1, did you misspeak when you said, in your framework, in your test, "exercise of market power" rather than "abuse of market power?" I think there is quite an important distinction if you're situating your framework in antitrust law. That's one clarification. And I have another one on the KeySpan case.

Speaker 1: I apologize if that's not in step with the thinking in Alberta. I usually think of it as an "exercise of market power" in FERC jurisdictional markets, because market power is mitigated in FERC jurisdictional markets. And so, if there is an exercise of market power, that would be an indication that somebody maybe was able to step outside their tariff or maybe they gained some market power. The fact is, you are correct from a more broad perspective. What you would be concerned with in the case of manipulative intent is that somebody was abusing whatever market power they had.

Question: OK, second thing. You said that FERC passed on the KeySpan Morgan Stanley case. My reading of that in the staff report from FERC was that they made a positive finding that there was no competition issue, you know, no tariff violation. There was a cap in place that would have mitigated market power. So that seems to be out of step with the kind of antitrust framework that you're putting forward. Is that correct? Am I right on that?

Speaker 1: Well, I was in the building when they were discussing that case. And I think they really had a problem of trying to figure out how market power could be exerted in their markets, and if market power was exerted, how do they deal with it? And the best I could tell from the decision was just "Well, we just don't have the authority to really rule on this case." And even though there may be findings that were presented, the result was not an outcome that foreclosed the case ultimately being brought up before the DOJ.

Question: With your theory on the triggers, if the trigger is economic trading, then would you stop your analysis? Assuming it's not fraud or exercise market power.

Speaker 1: Right. And again, what is economic? You have to remember an economist views what is economic relative to opportunity cost. So the fact of the matter is there have been manipulation cases at the FERC where the trader made money from an accounting perspective on the transactions that they executed, but the fact is, they could have made more money had they just sold the commodity upstream, rather than shipping it to this point and selling at a lower price. So when you think about what's uneconomic, you always have to think about it relative to opportunity cost.

Speaker 2.

I want to say, to begin with, I think this has been a great meeting. I've had conversations I didn't really expect to have. Most of you probably come here figuring something interesting will happen that you don't anticipate. And we had a great table at dinner last night. We were talking about withholding and market structure and it was just a lot of fun.

I guess there are three areas I'd like to touch on briefly. I might not get to all of them in these prepared remarks. I'll talk about *Hunter* some, because my perspective is probably a little different than either of these two fellows, and I'll talk some about the related markets cases. And there's another category of these cases, side payments or the like that, to me, are really important and not very well known.

When I first read *Hunter*, I thought, OK, he was trading on NYMEX, FERC doesn't have jurisdiction over NYMEX, why are we surprised? But, you know, the decision has some language that cuts broadly, and talks about transactions entering into the event horizon of the CFTC statute. And I just submit to you, we don't really know where that will lead. A lot of things are now futures contracts post Dodd-Frank that people didn't call futures contracts before. ICE, for example, had a number of products that people transacted in and they just sort of took the contract, changed a couple of things, but didn't really change the deal, and called them futures contracts, which, A, implies that they were already always futures contracts, but, B, tells you that right now they are. And if you're accused of manipulating those contracts, which might, to a first approximation, involve or seem to involve physical power or gas, we might have thought that was FERC jurisdictional. I'm not sure, after *Hunter*, that it is at all.

So we just don't know, really, where *Hunter* will lead, but as somebody who will be one of the people probably navigating whether to make that argument, or maybe making that argument, it's kind of a double or triple-edged sword, because when I first look at the question, I might say, "Gosh, the CFTC doesn't have these penalty guidelines, and they'll probably settle for attempted manipulation for 10 million bucks, and FERC's going to want 500 million dollars. So, gosh, maybe I'd rather it be CFTC jurisdictional." And then I think about the fact that there's something kind of cool about being in a FERC market manipulation case that you don't get if you're at the CFTC, at least in the power space, because there's this really cool thing called the filed rate doctrine that gives you a lot of protection against class action plaintiff shyster lawyers filing lawsuits against you, claiming you manipulated price outcomes and you should pay $5 billion or something like that. And if you're in CFTC land, you might have those guys all over you, and you might not be able to extract yourself and you might have to pay them, or maybe you get the case dismissed. If you're at FERC, you don't have that. So there's sort of gives and takes as to whether you'd want to play the *Hunter* card or not.

I've been on a couple panels with Speaker 1 and we debate these subjects, and so I'm going to react briefly to his slides, and ask maybe that some of the people who are more expert than I am bear in on a facet of the slides when we get to the Q and A, and then I'll talk about the final category.

I actually think that Speaker 1's slides are very useful in several ways, and I think they're very constructive in an important way that I don't think enforcement appreciates. And then I have a question about whether there's one aspect that ultimately is sustainably right. The trigger-target lexicon, I think, is a useful one. And it's sort of intuitively right, and we can all sort of imagine that if you can move the price in this trigger position and you have leverage and you make it back on volume, it's kind of like withholding. You withhold a product, and that hurts you because you don't sell it, but you make it back because it increases the earnings of the rest of your portfolio. And, in theory, that sounds like something we shouldn't like. And I'm happy to say that it should be looked at by regulators. I, for one, don't think it's really fraud. So I think FERC one day is going to lose in court the question of whether they can prosecute any of these cases, because they have to sort of invent fraud, and that's not going to be so successful, I don't think, in a de novo district court case about whether they sustained their arguments. But I'll agree that it's behavior that, maybe with an amended statute, FERC will continue to look at, and they'll look at it before they lose, if they lose anyway.

The part that enforcement doesn't like that I like about Speaker 1's little diagram is he says "Well, do you have uneconomic trading?" And I can tell you it's in the Deutsche Bank settlement order, and I've talked to those folks in enforcement and gone back and forth with them, that they don't look at that question quite the same way Speaker 1 does. I happen to think that's importantly because he's got training as an economist, and much as I really respect the enforcement guys--and look, they're very able opponents and they're very dedicated, and they really believe in public service--the lawyers don't have much use for economists. When I bring the economists in, they just basically kind of say, "We don't want to have to hire somebody like you, so we want something simple." But I don't think they care whether the trigger transactions are profitable or not. I think that they care about whether you knew that it might affect your target revenues, and we can talk about this in more detail--get into the weeds of *Deutsche Bank*. I think there are a lot of implications for their cases there about a sequence of events and the like, but we can save that for later on.

The part about Speaker 1's slides that I question (and I know some of your economist brethren sort of wonder about exactly how this might shake out, they have views that I can't really explain) is whether actually when you talk about uneconomic trading and your condo example, and an exercise of market power, whether those are really different things or not. And we've had this discussion, but after talking to traders and accountants, I tend to think you might sell your condo once that way--well, let's forget about condos. You might sell gas or power once that way. You might do it for a little while, but, eventually, they're going to catch up to you, the people on the other side, and they're going to come take your money. And you're not really going to move the market, unless you have market power.

If somebody's a financial player, what can you really do without someone going on the other side, unless we posit some sort of what economists might call microstructure issue, or some friction that means you can't really go on the other side successfully over time, and so, when I look at cases like that, I want to tell the enforcement guys, "What's your hypothesis of manipulation?" It would seem from just straight economics that if somebody is selling at a loss here, somebody else is going to get on the other side and take their money. Why isn't that happening? And maybe there's a reason. There can maybe be reasons. But that sort of question and answer is something you don't really hear very much, and so I'd like to hear a discussion later about what's the Venn diagram of uneconomic behavior and market power. So that's my main problem with Speaker 1's paper. I wonder about that question.

The final thing I just wanted to flag is that one of the things about these enforcement cases is that they could continue for quite some time and nobody knows really what's happening, and then something pops out, and everybody goes "What is this?" Like the Deutsche Bank case, you know--profitability isn't really a safe harbor. And everybody who wasn't involved in that case looked at it and went, "Gosh, we sort of thought it was." A lot of people did. If you were in the case, you'd sort of know there was a fight about this. And we see a little bit of an early warning flag in the PJM up-to congestion cases that I think really is going to end up maybe being dangerous or maybe important. Maybe it won't.

You ought to go look at those cases. They involve the fact that like all RTOs PJM collects more transmission loss dollars than it gives out, and so it's got to do something with its money. And some people say they should just give it to charity, because no matter what they do, it affects incentives. I don't know why they don't pay their own administrative overhead with it. PJM decided to give it back to whoever had transmission service. And it just so happens that at first, they declined to give it to certain financial traders who were doing so-called up-to congestion trading. And there are a lot of them. And then one day, they granted re-hearing. (They declined, by the way, because they thought it might change their incentives, might change what they do.) But then they granted re-hearing and said, "We're going to give you this money because it's unduly discriminatory for you not to give it." And so people started getting this money. And what do you know, just as FERC anticipated, it changed their incentives, because if you're booking transmission, you're engaged in a trade, and it costs you 20 cents per whatever to do it, and if somebody's giving you back 10 cents every now and then, that might change your threshold as to whether you transact. If they start giving you back 30 cents, so you're making money, and you might make money on your trade, you're going to see people do all sorts of things. And surprise, surprise, that's what people did. And the range of conduct here is pretty broad, but I sort of tease the FERC people about this case.

What do you expect to have happen? You're giving these people money through the settlements process, and as long as they see the money, they're going to react to it. Why don't you just not pay them the money? Why are you saying, "It's fraud to want to get paid money the tariff's paying you?" And yet, there is an unresolved fight about whether that's manipulation. There are open cases that have a couple of them, and there's one settlement that came out of *Ocean View*, where the commission said, "Well, the enforcement thinks it's fraud to sort of take this money," because the way it seems to be happening is you look back in time and you can say, "Ah-ha, a number of these transactions would never have been profitable without this supplemental revenue stream that we never thought you would actually transact with that as your target. And looking back, it's pivotal to the profit, and you knew this, so ah-ha, you must be guilty."

It's like you pretend there are blue dollars, green dollars, purple dollars, orange dollars. We pay people all these settlement streams, and those of you who have looked at RTO settlements know they're really complicated things. All this money's coming in. And if the government were to say, "Well, we're going to give you all these colors of money, but we're going to tell you ahead of time that you can't want the blue dollars. It's fraud if you try to get them, but we're going to pay them to you." I think a court might say, "That is just stupid, don't pay them the money. Why are you creating this incentive?" I think I'd win that case. But then if you say, "You know what, we're going to say after the fact that you can't want the blue dollars." Then I kind of go, "Well, I don't know what to do with that. Why didn't you tell them before?" Even if you told them before, it's a stupid rule. Just don't pay them the blue dollars. But to after the fact come in and say, "You never should have wanted these dollars we were paying out," to me, is a really hard, hard slog.

These problems also pop up in the baseline DR cases in some ways. I represented those folks, too. But there is this sort of burgeoning category of cases in the case log at FERC that have this property, and I just wanted to kind of sensitize you to them, because it's not something you'd expect, really—"Oh my gosh, I can't want the blue dollars," but that may actually be an issue.

Moderator: I have a clarifying question. You said that you would view raising *Hunter* as a two-edged sword. Could you maybe elaborate a bit on that?

Speaker 2: Because of the fact that it tends to open you up to collateral civil litigation that you could almost certainly avoid if you were in the power space. And it's the plaintiffs that come after you like flies. And then you have the fact that FERC wants so much more money. The CFTC uses more economic firepower to vet their cases. You could look at it in various ways. But I think, on balance, if the question is settling a CFTC-attempted manipulation case for not much money, versus the penalty guidelines at FERC, they get really big dollars, so that probably ends up driving the analysis, if you had the choice.

And by the way, you might raise these arguments and not win. I mean, it's just a question of whether the lawyers fight about it and what a judge does one day. But on the deference thing, if you have two agencies fighting with each other, why does one get deference? But remember, at least in a power case, almost anybody is going to be fighting this on a de novo basis in a federal district court, and then you're not going to get deference about what you think manipulation is, or whether you have jurisdiction over something. It's going to be a straight up call. At least by law.

Speaker 3.

Thank you for inviting me here to this panel. This has been interesting. I think both Speaker 1 and Speaker 2 recognized that maybe it wouldn't be that much fun to spend too much time talking about the effect of a DC circuit court case, and instead, talked about what they think about market manipulation. And I think I might do some of that, but I'm going to start by offering an opinion on how *Hunter* affects FERC's jurisdiction.

I think that the issue is the FTC's exclusive jurisdiction over NYMEX, which has now been established by *Hunter*, and whether, when you combine that with the expansion of its jurisdiction under Dodd-Frank (which also includes a number of new savings clauses, all of which is very murky and hard to sort through) it will result in a change in FERC's authority and its conduct with regard to market manipulation.

As I'll explain, I think that *Hunter* will lead to future jurisdictional fights, no doubt. It could have the effect of causing FERC to be more cautious. When you get your jurisdiction trimmed back in a court of appeals decision, it sometimes makes you think twice about what the next case you want to bring up is going to look like. But in the end, I doubt that *Hunter* will have any meaningful effect on FERC's enforcement authority.

And before I explain the reason why I think that, I want to just step back a little for some background on the broader context of the FERC's jurisdiction. FERC's jurisdiction is over transmission and the sale of power at wholesale.

Courts have said that is plenary and exclusive. The *Hunter* case talked about NYMEX as exclusive jurisdiction, but FERC has very well established exclusive jurisdiction as well. And FERC is required to ensure that all rates for or in connection with the sale of transmission or wholesale power are "just and reasonable."

FERC's focus is on physical markets. It's on ensuring that the price of delivered power is reasonable, and that's been FERC's charge since 1935. It didn't change in 2005. It's still FERC's jurisdiction and FERC's role today. Now, Congress gave FERC that role back in '35 because the Supreme Court had found that states lacked the power to regulate these interstate markets, and because the business of transmitting and selling wholesale power is connected with the public interest. It's an essential product with monopoly characteristics. So it was given to FERC to regulate.

Speaker 2 pointed out this immunity from civil liability. That's an interesting consequence. By Congress giving FERC exclusive jurisdiction over wholesale rates, that preempts courts from awarding civil damages based on any filed rate. In unregulated markets, you're subject to antitrust laws, you're subject to state consumer protection laws, anti-gouging laws, all sorts of tort laws that you are free from if you're a regulated utility selling under a filed rate. So what that means is that if FERC loses the ability to effectively police the markets for wholesale power, the prices for wholesale power, then those markets become less regulated than what we consider to be totally deregulated markets. You would both have ineffective FERC control and no civil check.

Now, FERC, until the '90s, just set just and reasonable rates based on costs, but then they started experimenting with market-based rates, the concept being that the market could do a better job of deciding what a just and reasonable rate is than FERC could do through accounting exercises. And by the end of the '90s, FERC had enthusiastically endorsed this as the way to go for the sale of power. Market-based pricing dominated. But then something happened in the year 2000 that shook FERC's attachment to market-based pricing, and that was the California power crisis, which began in May of 2000. And it lasted until June of 2001--13 months. You'd think somebody would have gotten on the other side of the trade. [LAUGHTER] So, beginning in the summer of 2000, prices rose to levels that had never before been seen, and then they stayed there. In a month, the market paid more than they paid in a year. It was thought that when the summer ended, the crisis would end with it, as load fell. But in fact, the crisis actually got worse as load fell. By the winter, California was suffering rolling blackouts day after day after day, even though the peak loads were 30,000 megawatts, when the same amount of installed capacity had kept the lights on a few months earlier with peak loads of 50,000 megawatts. By January, the biggest buyers, PG&E and SCE, were insolvent, with junk bond credit ratings. And that meant, under the rules of the ISO and PX tariffs, that they were out of the market. They had to serve almost all the customers in California, but they were now prohibited from buying electricity in the ISO and PX markets. So the state of California went into emergency session of the legislature and passed an act that gave the state the funding and the authority to start buying power on behalf of the state's retail customers.

Now, soon after all of this was breaking, some evidence started to emerge as to acts of manipulation. There were tapes that showed that a marketing affiliate was directing its generating company to falsify outages to coincide with their bidding strategy. And some other things involving the large generating companies started to emerge. But it wasn't until 2002, with the Enron bankruptcy and the release of the Enron memos that laid out strategies like "Deathstar" and "Get Shorty" and "Fat Boy," and the famous Enron manipulation strategies, that manipulation started to become a focus of what had happened. And then the ninth circuit issued an order of a type it's never issued before or since, that directed FERC to allow the California parties to conduct discovery of all of the suppliers in the market, even before the court had heard the appeal. That was called the 100 days of discovery.

The combination of the Enron memos and the various trader tapes and emails and the like that came out of the 100 days, I think served to cement in the minds of the public and policy makers that market manipulation was at the heart of what happened in the crisis. And I think that that's a good thing for the markets, because market manipulation is something you can fix by adding a few more policemen on the street, and then you can just move on with your market-based pricing program. Other things that were kicked around could have ended competition entirely. I mean, during the height of the crisis, the governor of California was threatening to use the National Guard to seize physically the power plants, and he actually did use state law to seize some contracts.

Politically, the backlash was enormous. And being able to pin this on manipulation allowed a plan to move forward. And this all led to Congress, in 2005, amending the Federal Power Act to add the protections on market manipulation that we're now talking about here. That was just part of an overall package. They created civil penalty authority up to a million dollars per violation per day. And that's not limited to market manipulation. That's any violation of Part Two of the Federal Power Act, potentially. They eliminated what had been a 60-day waiting period to get prospective refunds from the time of filing a complaint or a FERC order. And then, to deal with past periods, they gave the Commission this market manipulation authority, so that they could look back, investigate things and deal with past periods, all subject to this new penalty authority.

But the Energy Policy Act didn't change FERC's jurisdiction. It didn't change FERC's mission. FERC's focus remains in the physical market. What we learned from the California crisis is that during times of shortage, real or artificially created like we surely saw during the winter months, even small sellers can profitably get prices well above competitive levels, and, through Enron-type gaming strategies, sellers can game rules. All of these strategies involve bidding, selling, scheduling, transmitting physical power in the ISO markets or related markets. So it all falls within FERC's exclusive jurisdiction.

Now, what's changed since then is the incredible growth in the financial markets. Swaps are a much bigger part of everyday life on the part of most power companies than they were back then. But in terms of manipulation, the swaps are used as another opportunity to profit from manipulation. Swaps are also generally used for hedging, but I'm just saying that in the context of manipulation, their relevance is that they provide a mechanism to profit, but the swaps don't provide a very good method to manipulate physical markets, to manipulate the markets that FERC cares about.

Now, the *Hunter* decision to me wasn't surprising because of the reason that was on Speaker 1's slide about it. Hunter manipulated NYMEX. The trading rules of that are exclusively subject to the jurisdiction of the CFTC. And Hunter was doing that manipulation to profit through its swaps, which are also outside of FERC's jurisdiction.

So based on this decision, FERC has to either trust the CFTC to provide the integrity of the NYMEX market, or it could promulgate its own rules to regulate the ways in which public utilities subject to FERC's jurisdiction can use NYMEX prices as a component of their wholesale power rates. So FERC can't touch NYMEX and its operations under *Hunter*, but FERC still regulates wholesale rates, and may, if it found it necessary, find ways to address concerns it would have with the outcome of *Hunter*.

But the bigger question is, OK, *Hunter* is NYMEX. NYMEX is a special case. But Dodd-Frank expanded the scope of the CFTC's jurisdiction. It expanded it in ways that are still unclear, but it could include huge swaths of what we see as the swap market or what we didn't use to consider futures but could consider futures now.

So given that expansion in Dodd-Frank, when you put it together with the *Hunter* decision, is that going to prevent FERC from being able to do the job it's supposed to be able to do? And I think it's unclear. We're going to have to see it play out, but here's my view. I think that even if a very broad reading is given to the CFTC's jurisdiction over swaps (and I'm going to talk in a minute about what Speaker 2 said about futures markets, were you talking about like ICE as a potential —

Speaker 2: Well, ICE, a lot of their contracts now, they specifically call futures. They didn't used to say that, and they didn't change the specs when they changed the label. But you could have other platforms where the same thing would be true, where derivatives are traded but are related to power.

Speaker 3: You might be right that that's in play, and if it were to come to pass, and the ICE or the like were outside of FERC's jurisdiction, that would be a big deal.

As I'll explain in a minute, I doubt that's going to happen, but putting aside these physical trading platforms like ICE, and putting aside NYMEX, I think that the power sellers and buyers typically hedge with swaps that are tied to the physical trading points and the physical markets where they buy and sell. Because they're using them to hedge those markets. Attempts to manipulate the physical markets that those hedges are tied to will trigger FERC jurisdiction, because they would involve the sale or bidding or scheduling or transmission of power. But I don't see a significant risk that manipulation of a swap is going to move the price in the physical markets. These are derivatives that can profit from movements in the physical market, but by and large, I don't see them moving the physical market, so I don't think FERC needs jurisdiction over them in order to do its job of protecting the physical market from manipulation. So that's why I don't think that *Hunter* will materially change FERC's enforcement authority, though I freely acknowledge that Dodd-Frank is a mess, and there are scenarios that could play out that could change things significantly. But if I were betting on it, I would think that it's unlikely.

Now, on the point of whether ICE is going to fall outside of FERC's jurisdiction, Speaker 2 is right that under the Commodities Exchange Act, if it's a futures exchange, it may be treated just like NYMEX, and that could create significant problems for FERC's enforcement, because they trade physical.

But three points. First, Dodd-Frank includes a savings clause that, while it's a bit cryptic, appears to preserve FERC's jurisdiction over the things FERC had jurisdiction over before Dodd-Frank. And if that's the correct reading of the savings clause, then we could be looking at concurrent jurisdiction, which is an odd concept. It's really shared exclusive jurisdiction by two separate agencies. But I think the savings clause is a significant factor that I think makes it unlikely that FERC will be completely pushed out of that space.

Second, these are physical sales. ICE does both, but I'm talking about the physical sales through a brokerage platform. So what they're doing is matching buyers and sellers in physical arrangements. That's the heart of FERC's jurisdiction. It has been since '35. It hasn't changed. So I just don't think it's very likely that a court is going to find that somehow the CFTC's exclusive jurisdiction trumps that. But I'll further say, though, that even if there were limits put on how FERC could regulate a platform like ICE, FERC still regulates all the public utility sellers in ICE. So, if pushed, FERC may choose to take action to modify the rights of sellers with market-based rate authority relative to where they can transact and how they can transact. And I think we'd be better off not getting there, because it could end up with the value of platforms like ICE being reduced. But FERC has a lot of tools when we're talking about the physical sale of power. So I don't see a scenario, at least a very likely one, where FERC gets pushed out of that space.

There are a couple other things I want to mention. A Supreme Court case came out two weeks ago. It was *Arlington vs. FCC*, that said that under the Chevron doctrine, where agencies get deference for their own interpretation of the statute that they administer, at least if it's found to be ambiguous, the Supreme Court clarified that that even goes to the issue of whether you have jurisdiction. It's not just what you can do under the statute. It's whether you have authority over a certain area.

And the moderator asked, how does that play out here, because both agencies are talking about what it is they can or can't do? I don't think it has any relevance at all. I'm going to disagree a bit with Speaker 2, even though *de novo* review is true case by case, FERC's regulations that define what fraud means, I think, are not going to be *de novo*. Those are FERC regulations that, if there were *Chevron* deference, could well be given *Chevron* deference. The problem is that you have two different federal agencies. You can't give them both deference. And the *Hunter* case (and this was issued before the expansion of *Chevron* in the *Arlington vs. FCC* case), actually said this. It's right there in the *Hunter* case: "In reference to this jurisdictional turf war, [referring to the CFTC and FERC] we cannot defer to either agency's attempt to reconcile its statute with the other statute, because the premise of the *Chevron* deference is that Congress has delegated the administration of a particular statute to an executive branch agency. We've never deferred where two competing governmental entities assert conflicting jurisdictional claims." And that's what common sense would tell you, too. So the court's just going to have to sort it out if they have competing jurisdictional claims.

Question: You used the term "physical." Does that work? I mean, it sounds like it's very definitive, but in fact, a lot of these forward markets could be interpreted as financial. I mean, for natural gas, a firm contract is the right to flow if you choose. And certainly, the "contract path" arguably doesn't have a lot to do with physics. And so, how do you, from a legal point of view, separate physical from financial, or whatever? ICE goes to delivery. So in some sense, unless you liquidate your position, it's a physical contract. And where does "physical" fit into the law? I mean, I don't remember reading "physical" anywhere in the Power Act. Maybe I missed it.

Speaker 3: Let me clarify where I'm getting the word "physical." I'm getting it from the word "sale." I call a sale of electric energy physical. So to me, that means electric energy is being sold.

Question: But what if you liquidate that position before it goes to physical delivery?

Speaker 3: My view of the jurisdiction on this is that if you sign a contract that says, "I'm going to sell you X number of megawatts of energy delivered at a certain point on a certain day," that is a FERC-jurisdictional contract. If we weren't in a market-based rate world, you would have had to file that. That is a FERC jurisdictional transaction. Now, if you decide you're not going to make the sale, if you enter into an offsetting sale, if you book it out, my view is those are offsetting sales. Those are both FERC jurisdictional transactions, and FERC has said that. On the book out issue, for example, in its rules and guidelines on quarterly reporting, they've indicated that if you do a book out, you report both halves as separate transactions. You don't leave it off of your quarterly report, even though they said, in the exact same guidance, that if it's a financial transaction for which there is no physical delivery, (and I think the Commission used the word "physical," if I remember right) you don't report that on your EQR. So in my mind, jurisdiction follows sales of electric energy, and sales of electric energy are subject to the Commission's jurisdiction at the time that you agree to make them. If you later offset them or book them out or the like, that doesn't change them as FERC jurisdictional.

I don't know that I understood the question about contract path. I mean, one of the first things I was taught by an old contracts guy when I started out and I was trying to figure out this stream of transmission contracts he put together that didn't seem to match, that just seemed like a route that no electron could actually follow, was that he said, "Stop worrying about it, electricity doesn't flow without a contract." So that's how I've always viewed it. It's the contract that matters for what's jurisdictional and for what's commercial. The electrons will take care of themselves.

Speaker 2: Interesting view from a lawyer. [LAUGHTER] Can I just add on? I think that this question about what's physical is going to be a bigger hornet's nest than *Hunter*. There's a case at FERC on re-hearing, called *DC Energy*, where the FERC has said some things that are fascinating. Kind of screwy, I think, but that have all sorts of implications for enforcement. Where they say, "Well, but you intended to settle financially and not go physical." So now it matters what you intend. And they say, "You never acquired title, and you didn't pay for transmission, and you want to move money, not electrons." So they conclude that this is not a transaction that contemplates physical delivery or is a physical transaction.

And that applies to a lot of things. That applies to day-ahead transactions. That applies to transactions on platforms all over the place that never go physical, because everybody always flattens. That applies to a lot of things. And I think that in re-hearing the *DC Energy* case, this got pointed out--is FERC really saying that the transactions at issue there are going to be regulated by the CFTC, not FERC? Is that really what they mean to do? And this plays a little role in *Barclays*. This ends up being a real shifting situation, and I think it's actually a pretty big question that's an open one.

Speaker 3: On the DC Energy case, I'm going to agree with Speaker 2. There's some language in that decision, especially about intent, that I'm just not sure what you do with. But the thrust of that case was that FERC couldn't find any evidence that these were actual transactions. They didn't have any energy. They didn't have any transmission. They didn't have anything that would suggest this was anything but an internal non-physical transfer. But the thrust of the decision was there just wasn't any energy, no source for the energy, no source for the transmission, so we just don't believe it's physical. But I agree with Speaker 2 that if the Commission adopts an intent standard, then we're going in directions that could take us in a lot of different ways.

General Discussion.

Speaker 1: I wanted to address three issues that just came up from Speaker 1 and Speaker 2.

The first was, what is this uneconomic trading? It sounds a lot like market power. How do you differentiate between the two? So I just wanted to make a quick clarification, because most of the works that I've written have been on explaining and exploring uneconomic behavior as a way to trigger the possibility of manipulation. When you think about market power, whether you call it the exercise of market power or the abuse of market power, the exercise of market power always involves an act of withholding. So when you think of a monopoly, a monopoly withholds output and jacks price up to the top of the demand curve. Or if you're a monopsonist, you likewise restrict the output of your bids, and then you force the price down to marginal cost.

Uneconomic trading is different. Uneconomic trading is executed by forcing a market to overproduce. So offering units into the marketplace as a seller at a price that's below my marginal cost, that is an act of uneconomic trading that causes more units to trade in the marketplace than would trade were the market to be competitive. Likewise, if I wanted to be a buyer and force the price up, I simply could go in and buy uneconomically, and thus put upward pressure on prices. The condominium example was designed to show you that you don't need traditional market power to be able to trade uneconomically and to have a price effect. The main prerequisites for this working are simply lack of liquidity in the marketplace and inelasticity of supply and demand.

The second point I wanted to make is on clarifying a point that Speaker 2 raised regarding the idea of uneconomic trading as being a type of fraud. And, just very quickly, I'm setting up two scenarios. Let's assume that I have a short derivatives position tied to the end of day gas price. In scenario one, I'm going to assume that sometime toward the late part of the day, I put a false storage report into the marketplace, and everybody reads this storage report, and it says there's far more gas in storage than anybody could possibly have believed. People freak out. They start to sell. The price started the day at $5 a dekatherm. It ends up at $3, because people sell off in a panic.

Now consider scenario two. I don't say a word. I have the same derivatives position, but what I'm going to do is wait until the end of the trading day, and I'm just going to sell. And I'm selling as a price taker. But I'm just going to sell in volume and sell and sell and sell. Other people may panic. They may help the price to go down, but ultimately, the price once again falls to $3 a dekatherm. The fact of the matter is, the only difference between those two scenarios is who bears the loss on the manipulative trades. In the first case, where they false report goes into the marketplace, you have outright fraud as the trigger. All of the losses incurred in bringing the price down are incurred by others, someone other than the manipulator. By comparison, in the case of uneconomic trading, the manipulator bears some of that loss. Not all, if other people trade in sympathy. So when you think about intentional uneconomic trades, much like this second case, which would be referred to as "banging the close," either under an SEC statute, a CFTC statute, or a FERC statute, those trades are fraudulent because they are not a representation of the true value of the asset. All they are are fictitious prices put into the market to create a bias in the market price to benefit the manipulation.

There are some cases here that we can discuss, but again, I want to give you all time to talk about what you want to talk about. One point I would make, by the way, is that these same statutes that we're talking about are now in place in Europe. So just so you know, REMIT and market abuse directives are there. When we start thinking about extraterritoriality, we need to think beyond the box of just the FERC and the CFTC relative to *Amaranth*. The fact is, you can trade FTRs through nodal exchange on LCH Clearnet. So, through the London Clearinghouse, you can buy what are essentially swaps that tie to the electric grid. So when we think about the different positions that can be put together in order to manipulate markets, we have to remember, it's not just a question of physical versus financial. It's not just a question of is it FERC, or is it CFTC jurisdiction. It may be a question of how do we see all of these positions everywhere, because that's the only way to accurately evaluate the manipulator's behavior? Thank you.

Speaker 2: So Speaker 3 surely knew, when he designed his comments going off about California and how we got there, that I wasn't just going to sit here and say nothing. So I'll say a little bit and then we can move on. I think it's —

Speaker 3: I'd been hoping we could move on for 13 years.

Speaker 2: Stop suing my clients. [LAUGHTER] You know what? Let the market work. Let it go. It's very easy. The word irony is said to be really overused, but it seems right to me to say there's considerable irony to be having this argument in Alberta, after listening to the description of the Alberta energy market, and watching that duration curve and seeing all the inner rules where they're priced above their system marginal engineering cost by quite a lot, and there's no missing money problem and they let the market work and everything works fine.

And I will just make two broad rejoinders. One is from Bill's masterful summary of the testimony that he did for us in the last round of the refund case, where he said, you know, basically, look, all the things that people are said to have done, let's put allegations of withholding over to the side for a second. All the rest of this doesn't, amount to a hill of beans in this world. That's not going to really affect price outcomes in a significant way. Now, withholding, if you could show it, that'll certainly change price outcomes. But you know, he says, we've looked for 10 years. California's had the chance to pour over everything. Can we show evidence of withholding, which means you don't clear output to benefit your portfolio? And so you've got the trigger, if you will, and the target. And nobody's ever shown that, and California didn't show it this time, and at some point, I think he said, the lack of evidence becomes evidence. If they haven't shown real withholding after 13 years, let's move on, because obviously, it's not there.

And so what I would say about California is two broad-stroke things. There never was any showing of real withholding. There's all these other things that have catchy names that are mostly intertemporal arbitrage (that we like now, because we call it "virtual trading.") And they don't really affect price outcomes in any really important way. And then we have withholding that never was shown. And then if you were to just step back from the California crisis and imagine a world where nobody ever changed any of the price outcomes, but you kept the prices before and after, California would have had a price spike that lasted a good while. It's the only one they've ever had. And if you just take the time, those 15 (16? 17?) years since we started the market, and you just make a peanut butter spread of the price outcomes, and you look at whether you would have been able to support entry over that timeframe from market outcomes, the answer will be no. You wouldn't. There's not enough money in the market. They don't pay enough, as much as Alberta.

And if what you do is you start mitigating pieces of it, like, "Oh, we're going to have the refund period, we're going to re-price all of that to system marginal cost," then you're that much further underwater. And if we do what he wants to do, which is re-price the summer, then you know what? There never was a price spike in California, and I would say, "We know there was a shortage, guys. You need some sort of price response." Well, we're going to erase the whole thing, pretend like it never happened, and there's never any market response, there's never any price elevation. I think that's just kind of the wrong way to go. And I guess maybe the thing to take away from it is that our political systems, at least in California and Washington, DC, spurred by California, don't have the fortitude to let markets work that Alberta has, because I think if they had just sort of let things go and let retail rates increase and let demand respond like it did in San Diego, this probably all would have stopped, and there would have been a nice price spike and people would have maybe built, and we could have had a different outcome.

Question 1: Well, I don't want to get off n the California tangent, because we have more important things to talk about, but I would just amend Speaker 2's summary, which I agree with. The only statement on this that Governor Gray Davis ever made which made any sense was, "If I had wanted to let retail prices go up, I could have solved this problem in 20 minutes." [LAUGHTER] Probably right. And he was successful in manipulating the market by keeping those retail prices down in the midst of the crisis and he got recalled as a result.

But that wasn't what I wanted to talk about. I want to address Speaker 1's framework, and actually, what I'm going to say is --

Moderator: [To questioner] Actually, Speaker 3 wanted to respond on California [OVERLAPPING VOICES].

Questioner: If we had time, I'd be happy to go through the absence of evidence is now the evidence of absence, but I think that's a distracting comment. It's not really looking forward at this manipulation problem, which I think is much more important. Can I address Speaker 1's framework?

Moderator: Go ahead.

Questioner: So I have some gratuitous suggestions, and then I have a question. So let me do the gratuitous suggestions, which I think would make the framework better, and I don't think they're inconsistent with what you're saying, but I think would just make it better.

The first one is that I think you're actually hurting the argument for the framework by trying to make this exception that market power is different than manipulation. It's a form of manipulation, and I think it fits exactly into the framework. So if you divide the transaction into one transaction is withholding and the other is providing the power that you actually sell, you're losing money on the withholding, and it's uneconomic. And at the prices that we have, if you sold it, you would make money. So it's an uneconomic transaction. It changes the prices, and you make the money on the other transaction, which is consistent with your framework. So I don't think there really is a distinction. I think it's actually just like the other cases. The mechanisms for doing it are different, but the framework, I think, is completely consistent that way and I don't think you need to make that exception, because it gets a little confusing.

I think you've got to be a little careful about the point that you don't need market power, because it can't be literally true. And that's the other point that I would make. So I would introduce explicitly into the three-part diagram, so that you had six little boxes, ideas which you talked about while you were going through, but they kind of get lost in the conversation, and particularly the way it's been used by FERC, in my experience.

So the first one is that, for the trigger, there has to be some analysis of the impact. So how can you change the price? And how much can you change the price? So you talked about that in the process. You raise the price or lower the price and you lose money in the process of doing that, but you have to have a material effect on the price. And that's true, and I think it's very important, because I think one of the problems in a lot of the analyses that I've seen is that they don't address that question. They just assert it. [LAUGHTER] And you say, "Well, wait a minute, where did this come from?" And the numbers that get asserted sometimes are laughable, so it just couldn't be true. So I think making that explicit, that you have to address that impact part of the story, would be important.

Then, after the nexus and sometime around the target, I would put "leverage" in there as an explicit box, because leverage is part of the story. It interacts with the impact, so a small impact and big leverage is enough, and a big impact and small leverage is enough, and so forth, but you got to have that leverage. And I think that gets lost in the conversation lots of times, when people are talking about it. I don't think it's lost in what you said. I just think giving it more visibility would be a good idea, because in a lot of conversations I've had, people just say, "Well, you affected this price, so, therefore, you must have manipulated it." Well, wait a minute. How much, and could it have been done, and all that other kind of stuff, which is all part of your analysis, but it gets lost in the conversation.

Then, somewhere, I think, putting the scienter part of the story in a box would be a good idea, just to connect them to the other two.

So these are gratuitous suggestions for how to make it better. And I would offer a footnote, which is something you said quite explicitly and the diagram is completely consistent with, which is that the way this logic goes is this is like a chain, and each step is necessary, and if you don't satisfy a necessary condition, you break the chain and then you're done, so you didn't have manipulation.

I think what's actually happening in practice is that FERC is viewing each link as sufficient. So if they can demonstrate that a link exists, then you must have manipulated. And I think that's just logically wrong. I think it's inconsistent with the framework, and I think it's a serious problem. And I think that's a distinction between what's actually going on, versus what is described in this particular framework.

Now the question that I have--and this is what I find hard to deal with, and I don't know the answer myself—is Speaker 2's question, which I just will repeat here, which starts with, could I find an example where somebody could do this in the financial markets for an hour? I think it would be trivial. So the answer is, yes, you could. You just surprise everybody. You do something nobody was expecting, and you could exploit it if you're really smart and get away with it for an hour, and you can make a little bit of money for that hour. What I think is much harder is this question that Speaker 2 talked about, which is, can you do it over a sustained period of time? How can you maintain that impact effect over a sustained period of time if entry is relatively easy? And so the answer has got to be something about how entry is not easy, or some confounding effect, or some transaction cost story that's consistent—something that's persistent, as opposed to one-off.

And if the standard is that FERC is going to prevent one-off cases of market manipulation (not just persistent cases), well, that's going to be good for my retirement. It's going to be good for lots of peoples' retirements, because there's going to be endless work related to this, because these cases will be all over the place. But I think the standard ought to be something that can be sustained, that's material, that has a long-term effect, and I think that's a much harder problem, but you didn't talk about that. And so I just wonder, how do you address that problem?

Speaker 2: That's really the core, I think of the difficulty with these cases right now.

Speaker 1: And do you mind if I address your gratuitous comments, as well? I greatly appreciate them. I do. And I want to address them. First, on the market power versus uneconomic trading concept, there are some who would refer to somebody going in to the market at a time when there's very little liquidity, and just placing a hail of trades to push a price in a particular direction, as just an example of market power. The reason I've tried to bifurcate the two concepts is because we typically think of market power as an antitrust law concept. It's something for which there's an existing core, an existing theory that deals with HHIs and upward pricing pressure, and yada yada yada. The fact is, the example of the gas trader who went in at the end and banged the close, that really wasn't market power, inasmuch as those transactions were fraudulent. That's why I try to keep these things separate, because I don't think of uneconomic trading as being an exercise in market power, per se. I see it as an exercise of fraud.

Questioner: My argument is that the logic goes the other way. Market power is uneconomic trading, fraud is uneconomic trading, you know, doing some of these things that you're talking about is uneconomic trading. It's not that uneconomic trading is market power. So the logic goes the other way.

Speaker 1: And this actually gets to one of your other points. The fact is, the FERC chose to adopt a fraud-based manipulation statute based on 10b-5 (of the Securities Exchange Act). And the reason they chose that was in part because they didn't want to have to prove an artificial price, which is getting to your point about proving harm. Specifically, the way the FERC has interpreted its statute, and the reason why now the CFTC has the same statute, is that in order to prove a violation, an attempted manipulation, if you will, proving an artificial price is not necessarily part of that. The penalty guidelines at FERC require you to show harm, and scale the penalty accordingly. But the fact is, to find somebody guilty of attempted manipulation, you don't have to prove an artificial price. That's why they adopted the fraud-based statutes.

Questioner: That's not consistent with what you said, though, which was that you have to move the market price.

Speaker 1: The idea of the trigger, the target, and the nexus is that you're showing an intent to move price. And you had mentioned that I don't have intent anywhere in here, and I apologize if this doesn't explicitly state that. But, yes, you have to show that the trader is intentionally trying to move a price through one of these three acts.

Questioner: But if he fails?

Speaker 1: The fact is, they intended to do it. If it didn't happen, they weren't successful –

Speaker 2: What you're saying is that you could violate the statutory provision and the regulation without the government proving artificial price. I understand that theory, but you yourself, I think, pointed out correctly that because of the penalty guidelines and them wanting to show harm, they sort of threw the baby out with the bathwater. And they are claiming you moved price. And what I hear the questioner saying is there are a lot of reasons why one might embrace the notion of saying that's an exercise in market power. Professor Craig Pirrong does the same thing. He would say that this is a market power manipulation, as distinct from your lying example. But the problem may be that you're dealing with people at FERC who can be concerned that somebody like me will come in and say, "Ah-ha, yes, it may be a manipulation, but it's not fraud." And then you have a problem. But I keep coming back to the question of, if you're moving the price, what is wrong with calling that market power? Why isn't it market power in some sense, maybe on a transitory basis, because of some friction or transaction cost or something?

Speaker 1: It's the mechanism. Again, traditional market power is exercised through an act of withholding, whereas uneconomic trading is causing the market to overproduce. So that's relevant.

Speaker 2: Well, it's injecting excess supply. It's kind of the obverse of withholding.

Speaker 1: Or excess demand. Right?

Questioner: Right, monopsony, monopoly, and all that kind of stuff. But if you don't have the impact, that measure of how much you moved the market price, then you also don't need the leverage measure.

Speaker 2: Right, you can't measure leverage.

Questioner: These are twinned.

Speaker 1: Well, the leverage is simply a function of the profitability of the manipulation.

Questioner: But the manipulation is only profitable if you move the price.

Speaker 2: You can't tell that without the leverage.

Questioner: Right. I just don't think you can get away with this. [LAUGHTER]

Speaker 1: See, the importance of this is you'll notice that in the second box. next to target, is "Did they hold financially leveraged positions that could profit from the manipulation?" The reason that is there is as a protection to traders. The fact is, (and we had a circular diagram on slide five) if that target is only big enough to offset half of the losses, for example, in an uneconomic trade, that "target" is really just a hedge. Because the leverage is not there to consider this a manipulation.

Speaker 2: Or it could be entirely unrelated.

Speaker 1: It could be. But the fact is –

Questioner: No, I don't understand that. You can't analyze that question about how much you recoup without knowing how much you changed the price.

Speaker 2: Right. You have to know impact and volume.

Speaker 1: You have the ability, if you take someone's trading book, to deconstruct it and see what their exposure is at a particular trading point at a particular time. And so you may know they're long 1,000 contracts of whatever equivalent. And then you are able to look at that versus the triggering transactions and say, "Wait a minute, OK, well, if they lost money on 100 contracts over here, they lose $100, but they make $1,000 over here."

Questioner: But that analysis requires knowing the delta p (how much they changed the price).

Speaker 2: Right, change in price. Times a thousand.

Questioner: I think it's the right analysis to do with the delta p, to see if they raise the price over here enough so that with the leverage, they could make up the money back over there…but you can't take the base, if the so-called hedge was already there for other reasons.

Speaker 1: If you're trying to calculate a harm, I agree. But if you are trying to prove that the components of the manipulation are in place… Take the Libor, for example, where we have three banks that have pled guilty to attempting to manipulate the Libor. There's no harm that's been shown in any of those cases, because of the way the Libor is constructed. But the fact of the matter is, they were attempting to manipulate the Libor in doing what they did. They pled guilty to it. So you don't have to prove harm for this to apply. The fact is, however, the three pieces of the framework still do.

Speaker 2: But that wasn't even a fraud-based manipulation case, was it?

Questioner: This just doesn't make any sense. This is just double talk. The presentation, I agree with. This, I don't understand--unless it's just that I thought I was going to move it enough so that when I moved it enough, I was going to make money over here, and if it's all just in my head, and the reality doesn't have anything to do with it--but the reality's got to have something to do with it.

Speaker 1: Can I rephrase it a bit? Let's say that I have 1,000 megawatt FTR that synchs at a point. And I know that if I place virtual bids, decs, that I'm going to have a tendency to raise the price at that synch, which could potentially benefit the value of my FTR because of the congestion payment. So the fact is, does it matter, if I'm putting a 100 megawatt virtual in, that I have a 50 megawatt FTR? Or a 200 megawatt FTR, or a 1,000 megawatt FTR? Of course it's important. The more leverage that you have built up there, the more potential you have to make money off the manipulation, whether it works or not.

Questioner: But that's precisely because a smaller change in the price leverages more, and therefore you could still make more money on it for any given change in price. But if you don't get enough change in price in order to make the profit, I don't understand why –-

Speaker 2: You can still have a minuscule change in price and lose money with a whole lot of leverage on a net basis, right?

Speaker 1: If the trigger and the target are both tied to the same price, whatever you lose in the trigger should give you, assuming that you're dealing with contractual equivalents, that same size loss, whatever the delta P is, as you're calling it, multiplied times whatever the leverage is.

Speaker 2: Why would your loss on the triggering product have to be the same scale as your unit gain on the financial side? I mean, maybe an FTR is a bad example, but you could lose a lot more money and have just a minuscule price effect, couldn't you?

Speaker 1: That's possible. But, I mean, if you place a transaction, say, for example, we're talking about –-

Questioner: Let's go back to your example about trading over here versus trading over there and opportunity cost. They made money on the transaction. You said they could have made more money with a different transaction. That is inherently a delta P story. I end my case.

Speaker 1: So you're saying in that case, there's an opportunity cost that you're measuring. You have to have a but-for competitive price to compare against…

Questioner: Somehow you have to tell me what the impact is. And then you have to compare the impact to the leverage to see whether that makes up for it, and if it's just one to one, or not, then-- the contracts aren't going to be the same. They're almost never the same. There'll be some indirect effect, and so, you have to go through all that story, but I don't see how you can have a manipulation case that does not specify how you changed the price and how much you changed the price.

Speaker 1: Of course, that's the Brian Hunter case, because they didn't --

Questioner: There's a whole series of decisions that have been made that make no sense to me, so citing some of those doesn't help defeat the argument here. I don't think it's consistent with the framework as I understood it. And I think what you said this morning makes perfectly good sense, and I agree with it. And I think it's better than you think it is.

Speaker 2: This has been sort of the unexplored underbelly in a lot of ways of a lot of these cases, because it's hard to figure out what would have happened if the conduct that you're complaining about wasn't there. It's not maybe as simple as just deleting the conduct or deleting the trades, or whatever, or maybe it is. And this requires expert economic analysis, often, and it's expensive to do, and what I have seen is I've seen the government just keep sort of doing different things, apparently designed not with any consistent framework being developed, but just to see, "Well, what's a big number we can come up with?" And in fact, they sort of change sides on how they do these things from case to case. But you ultimately need a litigated resolution of some of these to get into questions about things like, is this junk science or not, and there are actually some interesting pro-government cases out of the SEC case law that say the government's but-for case doesn't have to be perfect because it's not their fault that the market was supposedly polluted by this conduct, and so complaining that we can't perfectly reassemble the world doesn't work for the defense. But it shouldn't work either to just kind of bluff your way through and say, "There was this effect" that you never really have to ground in analysis.

Questioner: Because you said it yourself, Speaker 1, in the presentation, that every transaction affects the price, in reality. So there must be something special about manipulation other than that you did a transaction…

Speaker 1: This kind of feeds into the question that you asked me actually, which is, how can somebody do this again and again and again and get away with it?

Questioner: That's a much harder question. And if you have a good answer there, I'd like to know.

Speaker 1: Well, I hope I do. [LAUGHTER] But again, this gets into the idea that when somebody is manipulating over the course of time, there are going to be periods where they have no effect. They may be trying to do the same thing that works when the constraints bind, but maybe the constraints don't bind. So in that case, you really don't see a price effect from what they did. That doesn't mean that it wasn't part of a manipulative scheme that they were trying to enact. First point.

Second point. There may be asymmetries between the instruments from the perspective of risk or from the perspective of transaction costs that make it difficult for somebody to take the opposite side of whatever it is the manipulator is doing. So, for example, use the FTR using the decs. Let's say that I'm placing an excessive number of decs into the marketplace. I'm causing divergence between the day-ahead and real-time price. The fact is, placing an inc obviously is something that would take the effect of the dec, and it would also take some money out of the market. But as we know, the different RTOs have different charges that they allocate to incs versus what they allocate to decs. So there may be a transaction cost element in the form of uplift or operating surcharges or whatever that makes those incs less desirable, or more expensive to place.

Another issue, though, is the asymmetry in terms of the exposure to the real time price. If I place a dec, I'm buying in the day ahead, and I'm selling in the real time. In markets such as Alberta, I know you don't have a day two system, but the fact is, oftentimes the lowest price you're going to get in the marketplace is zero. So by definition my risk is capped in terms of the real time price. By comparison, if I place an inc into the marketplace, I'm selling in the day ahead, and I have to buy the power back in the real time. And the fact is, whatever the cap is in the marketplace, it's the only threshold that's going to save me if something very odd happens. So it could be that these manipulation cases are sustainable, at least over periods of time, because of such constraints and because of such asymmetries.

Questioner: That's a very good argument. But it has implications. So let's take the transaction costs version of that argument and set aside risk aversion for the moment, and say, now that's what's going on, then the amount that you could impact things, the delta, should be bounded by the transaction costs. You couldn't sustain it over a long period of time, because if you were sustaining it over a long period of time, and then there's a transaction cost, it's still worth it for people to enter, because they could overcome the transaction cost.

Speaker 1: Right.

Questioner: So then we should be looking in these cases for the discussion of the transaction cost and how much of that bounds it and whether or not the prices that they're talking about would have been enough to achieve with the leverage and all this other kinds of stuff. Of which we see nothing.

My point is not that there are not arguments where you may have these asymmetries, where you may have some transaction costs, where you may have some problem or defect in the market. Rather, it's not even addressed. It just says, "We think you are trying to manipulate the price and therefore we're on our way," and I just think that's inconsistent with your framework. I think it's inconsistent with basic logic, and, boy, if I was a trader, it would make me real nervous.

Speaker 1: And I think that's going to be one of the gray areas that I hope will get litigated. But as with many of these cases, it probably will come out and then just be settled.

Speaker 2: Let's explore for a second why the questioner says that if he were a trader, it would make him real nervous. Because you didn't maybe expect us to go off in this direction, but we have, and we've talked about it before. You step back from your presentation, and I think it's been a good exchange, to talk about, well, here's a way in which you can have these hiccups in the way the market is structured that make it hard for somebody to combat someone who's pushing price in a way that departs from the fundamentals. And having specific arguments about that would be the right way to proceed, and I've never been successful at drawing those arguments out yet.

But what does that mean? That means that right now, you could be found to potentially be suspected of manipulation where you have physical transactions and you have financial transactions, and they are linked in some fashion, and you haven't had a lobotomy, so you happen to be aware of that fact. But you're actually trying, we can hypothesize, to make money in the physical trade world, because your parents raised you well. You don't go around trying to lose money to help something else. That doesn't seem right. You don't do that. But you've been doing both at the same time. And one problem is that if the test is after the fact, if we run our forensics and we sift through your book and we see that you did both of these things at the same time, and because you have a point of view, more than half the time, you did them directionally in the same way, such that we can hypothesize that obviously, you must have had some effect in the physical market and it benefited your financial positions, because why would you be doing both of these things? Then it quickly becomes this scheme that kind of arises from the ashes. And all of a sudden, this is why you did everything.

And if we're not going to actually figure out what the price effect is, but assume it exists, then you become guilty by accident maybe far too frequently. When I fight about these questions with some people who maybe have spoken here before, for example, they'll just say, "We don't think we really have to get into whether you had a price effect, because we know you had leverage and we know you were in this market. You don't have to be in this other market that's connected to your financial positions, but you were, so you must have been trying to trample on the price outcome somehow, and you had bad thoughts in your mind and you were transacting, and that's all we have to do." And there's never any precision about what price effect you have, whether this really could make money, and all of a sudden, what is, I would submit to you, more likely than just about anything, just an accidental mishmash of positions that you're looking at after the fact, that will, in any given number of circumstances, randomly produce this combination of events, it becomes manipulation, and you assume intent based on the existence of the positions and nothing more, and all of a sudden, you're off to the races.

And that could happen accidentally to practically anybody unless you just stop trading related positions, like some companies have done—"We're just going to stop doing this because we can't tell where the line is, and we don't know what to say when the enforcement comes knocking on our door and they find these positions exist after the fact, so we just have to stop." And if somebody comes to me and says, "How do I not stop and how do I eliminate this risk?" I don't know. I don't know. I have no answer for you.

Speaker 1: This was created as a tool to assist compliance. This is a tool to assist traders and compliance officers in thinking about the way they're putting together the book, so you don't have to deal with what Speaker 2 was talking about. And he's right. A lot of people have said, "You know what, I'm not going to trade financial product anymore because it's just too risky. I don't want the FERC coming after me." That's not what you want. You want them to access the financial markets. That's why they're there. They help them hedge. They help them --

Speaker 2: Enforcement doesn't like that first layer on your slides.

Speaker 1: They don't like the fact that I have these circles off to the side.

Speaker 2: Yeah, they don't like the off ramps. They don't like having to show that this is uneconomic behavior measured to what, and what price effect. They don't like to get into that, because it's complicated. They just like to assume it, because, "We know you have this related position."

Speaker 1: What this pragmatically comes down to, in effect, is if you are a compliance officer and you have a trader who's thinking about doing some sort of weird strategy, you need to show how that strategy is designed to make money on a standalone basis, and to the questioner, I know you've talked about the standalone profitability test as well, essentially for measuring whether something is uneconomic or not. It's not that somebody loses money. People lose money all the time. Half of all trades lose money. But it has to be a strategy that was intended to make money. The fact is, if you continue to execute a losing strategy again and again and again, for awhile, hey, that might be OK, but at some point, you've got to say, "Did this person really do this just as part of trying to make money, or could there be something else that's on the side that stands to benefit from it?" By the way, the key thing that helps establish intent for the prosecution are things like trader tapes, IMs, emails, things talking about "The Hammer," "Deathstar" schemes, and, for whatever reason, profanity. When people are doing something wrong, there's a hail of F bombs around it. [LAUGHTER] And you know, the agencies have transcription software that will find all of the different misspellings that the traders use for that word to get around whatever their internal censors are. So, anyway, you look at it three years after the fact, when a 23 year old is going through your data at the FERC, and that language doesn't look good. So it's that objective evidence of intent that backs up the economic evidence shown through this framework.

Moderator: We've got some other cards up, so let me move on.

Comment: No, I think this is --

Moderator: The question is whether we get three people engaged in market abuse here.

Question 2: Speaker 1, I think you said at one point that if you're losing on one side of a transaction, it could end up being a hedge. And if it's totally offsetting, it's a perfect hedge. But if it made too much, then it could get into a manipulation. And the other thing was when you were talking about if you have, say, an FTR and a virtual position, and sometimes the constraint binds and sometimes it doesn't bind--but what if you've got a trader, and he thinks it's going to bind so he puts on a position thinking it's going to bind. It doesn't bind. He just flat out made a bad trade because it just didn't happen, and it happens he has a financial position somewhere else that…would that end up being manipulative under here, because he thought maybe he was going to be able to manipulate and it never bound, and so, it never happened?

Speaker 1: You know, if somebody does something like that once…the fact is, half of all trades would be expected to lose money in a fair market. And that's not necessarily true given the distribution of the way things actually work, but the fact is that somebody lost money, say for example, on a virtual trade in one hour. Can you infer manipulation from that? Absolutely not. This is why typically, you will see a pattern, an anomalous pattern of trading. For example, in the *Amaranth* case, Brian Hunter, it wasn't just one month that this was being done in. It was actually three months. In most of these cases, you will see behavior that was repeated over a period of time, such that at some point, the trader or whoever is responsible for compliance for that trader would, should, could ask the question, "Why am I losing money over here?" We look to the side then, and say, "Did they have something stacked up to benefit from that?" If the answer to that is yes, the agency is going to say, "I want your trader tapes." They go searching through it. And if they can get all these pieces together, and they can find objective evidence, well, then you have a problem.

Question 3: The question is for Speaker 1. You talked in your presentation about how the CFTC granted exemptions to various RTOs, but in those exemptions, they retained enforcement. It's my understanding that the CFTC is still retaining the right to come in on enforcement matters with respect to fraud. The only real limitation being, I think, budgetary and just general bandwidth, whether they'll do it. But that sort of remains out there, because the CFTC enforcement staff, at least in my meetings with them, is a lot less friendly than the other divisions.

I do have financial players now who are coming in and saying that they've quit trading in the secondary markets, financial positions, at the same time that they're trading physical or virtual contracts that are tied to physical delivery, because they can't take the risk.

Speaker 1: Right. And again, that's just a shame. And that's a function of lack of clarity in terms of what enforcement is actually doing. I think everybody would agree that right now we have--is it the Gila River case as the only actual admitted act of market manipulation that the FERC has at this point? All the other cases have been settlements, where people neither admitted nor denied the behavior. So I understand traders are scared, and I hear that same thing, too. Again, the reason why I put this together is to help, for example, a trader to be able to say and show a regulator, first, "No, I wasn't trying to lose money on these trades. I had a profitable strategy in mind, here it is," and then second, "And oh, by the way, all these positions that you say I'm trying to manipulate, they're only a hedge." So the idea is to have your defense ready. If the agency comes calling, there's really not much you can do about it from the investigation standpoint. So in that case, your best offense is a good defense, and to make sure that you have these boxes checked, if you can.

Question 4: Thanks for the great discussion. This has been really interesting. My question to the panel is, using as simple a language as you possibly can, and no more than two lines, can you give some guidance to a fictional market participant so they can tell a manipulative act from a non-manipulative one?

Speaker 2: Do I have to give my own point of view, or does it have to be something I think the FERC agrees with?

Questioner: Definitely not FERC because we're not regulated by FERC.

Speaker 2: If you're engaging in transactions that have no substance in and of themselves, but meet some collateral purpose, it's certainly a very good question whether they're manipulation—wash trades, a true intentionally money-losing transaction that nobody would do. It's not like a hedge unrelated to something else. It's not part of an information collection strategy. It's just dumb. Again, why would you do that? You scratch your head.

Those are things that lead to the sort of things we're talking about, but you have to posit the absence of any explanation for them. And it may be they're just acts of idiocy, by the way. There might not be some nefarious motive.

You could talk about lying as another species. If you're just lying to somebody, that might be manipulation. It might just be fraud. It might be just bad, unethical behavior, but it could be you know, price misreporting, which is another example.

Speaker 1: I just would rephrase the first box to just say, "Don't trade fraudulently. Don't trade uneconomically, and don't abuse market power." Because, again, if you're not doing one of those three things, your transactions are legitimate. And the agencies may not want to declare any safe harbors, but if you can show that you were trying to make money on a standalone basis, and you weren't doing anything that was fraudulent per se…

The fact is, ultimately, this has to be litigated, and for an agency to go in front of a judge or jury and try to argue that a transaction that was trying to make money according to a real strategy, here it is, was somehow putting in place this great scheme, is insane. And the fact is, there has to be a presumption of transactional legitimacy that follows open market transactions. If not, the economy falls apart. So it's the government's burden of proof, I would assert, to get beyond that presumption of transactional legitimacy by throwing the behavior into one of these three categories.

Speaker 3: I think the three categories sound right. None of the agencies want to say this is a safe harbor because I think they're all afraid the traders are smarter than they are, which might be true. So if they define something, somebody will just figure out a way around it. But those three categories cover everything I can imagine.

Question 5: I echo the previous comment that this has been a fantastic discussion. I could talk for hours with you guys, because market power's been certainly one of my interesting topics. It appears we're all in the same game, especially with respect to Speaker 3's comments about acting in the public interest and ensuring that we in the end get the all-in least cost delivered energy. Maybe someday we should put Pandora back in the box and just re-regulate and get to marginal cost, but short of that, short of putting Pandora back in the box, as an economist, you want to be looking for absolute abuses of market power, for sure. So if you're looking for fraud and all that kind of stuff, you need to do that.

But in Alberta (and I'm tempted to re-cast some of the earlier characterizations of Alberta) we look at market power. We're looking more for abuse of market power. We have rules to mitigate against physical withholding, in the main, even though it looks like we're allowing market power in allowing economic withholding. What we're really doing is saying that participants are enabled to take risk in their positions. So if you believe that participants can take risk in their position, my question is, isn't all of this litigation and all this discussion, isn't it dangerously close to being in the way of allowing that competition and putting participants in a place where they feel they're not enabled to submit bids that are at risk because they feel like any time they do that, they're going to be investigated? I mean, aren't they dangerously close to suppressing the competition that we need to make this market work?

And so I just wonder where you think that line is, and have we gone too far, and how do we put some of that back in the box so that participants feel that they can actually compete?

Speaker 3: First, I really appreciate the clarifications about what Alberta does, because I was unclear just how much unilateral market power is allowed, and if anybody's really watching. Speaker 2 said earlier, when he was talking about California, that it's ironic that we're talking about the California problem, while yesterday we heard that Alberta seems to have it right. It just makes me wonder. I mean what we saw from the scatter diagrams and things yesterday is it looks like in five or 10% of the hours, there may be some market power that can be exercised. And that happens when a big plant goes offline, for example, or you have some other system contingency or maybe a really big load day.

What would happen if this were not five or 10% of the hours, but every single day? And what if the amount of market power being exercised doesn't magically put you just above long-run marginal cost, but bankrupts all of your buyers? I think that what's going on in Alberta is fascinating, but I just don't know that it's exportable, and I don't think it's much of an example for what happened in the year 2000 in California. And it just makes me think, in answering your question, there is always a cost to regulation that you can eliminate by not regulating. And you always have to examine whether the costs exceed the benefits of the regulation. And the costs here aren't just the costs of the regulator. They're the costs of hiring lawyers and disrupting your life and your business. These are real costs.

Speaker 2: And they're created by who?

Speaker 3: Well, the California stuff, that was actually something that had price effects. That could be proven. That was kind of real, and it led to this new enforcement regime. Because what was going on with California, which I hope never happens again anywhere on either side of the border, is that the market was so dysfunctional that prices went higher than they'd ever been, and yet nobody was coming in to build. People were running away from the market. It became dysfunctional to the point of actually repelling investment, even at high prices. When prices go high enough, to the point where the buyers are running out of money, to the point where the governor is threatening to seize assets, now it's like deciding to invest in a Third World dictatorship.

You can't have a working market that's being manipulated, because you have to have stability and the rule of law. That's sort of a precondition we've always taken for granted in this country, but you can have extreme dysfunction that actually undermines every economic principle and just throws you into a realm of political infeasibility, and economically, it's just not sustainable.

Someone mentioned a quote from Governor Davis about how we could have fixed this in 20 minutes if we had just let the rates get passed through to retail customers. Actually, they were passed through to some. There are three utilities in California. San Diego Gas and Electric wasn't subject to a rate cap during the crisis. Their rates went up, and that's where everything hit the fan. And before the summer was out, Congress moved to San Diego and held live hearings there that were covered worldwide. If the governor had taken that step of removing the caps, then you might not have had the utilities sending their lawyers after you in the same way. You just would have had the villagers marching on you with torches and dogs. So there is a big cost to manipulation.

And if the result of this new market manipulation authority that FERC has is to put a cop on the beat that prevents another crisis from happening and gives the market comfort that I can invest in this market, not worrying about whether somebody is going to come in and manipulate the price downward and upset my reasonable expectations of revenue, and buyers and states and the like can decide to participate in the market free of fear that it's going to be manipulated in a way that damages them, then that helps markets. It helps investment. And you have to make sure you at least have that level of regulation, where you can keep the markets stable and legal and stay out of Third World dictatorship territory.

But I do get worried when I look at some of the things that are being investigated. I hear Speaker 2's story. I'm not involved in that case (that is still, I assume, not public), but he's suggesting that there is a case where people are being sent money under a tariff, money they're entitled to, and of course that changes their incentives and makes them do things they wouldn't have done if they weren't getting this free money. Just knowing those facts and nothing more, I'd say it would be a travesty if that got prosecuted, and to even be raising it with people is raising the cost of regulation in a way that could be tipping the balance to the other side. That's a case where you just fix the rule and move on.

I don't know exactly where the line is, but I think that enforcement is important, because the potential harm is catastrophic, and just letting the market work only works if the market works. And power markets have quirks about their delivery system. They have relatively inelastic demand curves, and there are opportunities for abuse. So I'm a strong believer that there is a need for a continuing role in policing against market manipulation, but I also agree with the sentiment of your question, that we have to be careful that we don't do that in a way that imposes unreasonable costs on market participants. That's counterproductive.

Question 6: Just one point of clarification which leads into my question. We saw in one of the presentations yesterday the scatter diagram of pricing in Alberta, and you made the point, Speaker 3, that this looks like some market power being employed. I think what's also important to appreciate is that the market is also highly contracted in Alberta. The MSA (Market

Surveillance Administrator) did a paper last year where they surveyed industrial loads. 24% of the province's load responded. 90% of those consumers had some degree of physical or financial hedge. So they were not paying the spot market price in many respects.

Now this gets me to my question, which is that we're focusing on spot market events, and I'd ask, from anyone in the panel, what is the state of the art on the dialog around sustained price excursions, or material impacts, or the allowance for competitive response to these market events? I imagine that's probably raised as due diligence matters before FERC, but can you comment on what is a sustained event? What is a material event, and how do we allow for competitive response to some of these behaviors in the marketplace? Or is it binary? Are we looking at market power abuse issues in real time?

Speaker 2: I'll take a first stab. If we're talking about the RTO markets, which are kind of, I guess, the natural thing to talk about in the context of your question, many of the sellers are subject to mitigation in terms of their offers in any of the spot markets, be they forward or real-time. And their ability to offer high prices is limited, typically, to some sort of forecast metric of marginal cost, and so there's not a lot that can be done until somebody comes along and creates an automated scarcity pricing formula, such that we have prices go to high levels when certain preset conditions like going short on reserves are met, or some external exogenous condition of scarcity, I guess one would say. And so, partly because of what happened in California, partly because the agency thinks that well, we should have concerns if someone's offering in at high prices just in general, where we think you have market power anyway, you're very limited. If you don't have market power, you might offer at a high price, and then if it repeatedly clears, you typically find yourself answering questions about it.

So there's an element of self mitigation that a number of market participants will engage in because they figure that that will be ostentatious and attract attention. And so some businesses just simply will not test the waters very broadly if they're not mitigated on a preset basis. And that's maybe the shadow of the California crisis. So you do have high prices occasionally, because somebody offered them, or for other reasons. And if it's some system event like the CAISO situation a while back when suddenly prices were at $6,000, and they reprinted it to $200, or whatever they did. So a lot of times these prices don't stick from the market operators' perspective.

Question 7: Speaker 1, I think you made the comment that you put together your chart to help compliance officers and the like to analyze these hypothetical or potential manipulation instances. My question is really leading up to that. The reality is that I think we're all faced in the market with looking at hundreds of transactions on a daily basis. Have you given any thought as to how do we identify those triggers? What's a good way to know that, as a company, I'm doing my diligence that I'm not missing those triggers?

Speaker 1: When I left the FERC, actually, one of my last tasks was being the head of the pilot project for surveillance. And we were asking exactly that question. What sort of screens do you put in place that might tip you off that something untoward is happening? And inevitably, whenever you get trading data, of course, it's just a morass of information and has to be boiled down and distilled. What I always am interested in, though, is looking at positions as they are accumulated and built during the day and as they are liquidated, and looking at the profitability of those on a running total. And so, when you see, for example, somebody building two positions that, say, are directionally linked, and if one is liquidated into the other, there's nothing necessarily wrong with that. That's what hedges are for, for example. But sometimes you'll see some asymmetries there in terms of the way that those positions are put together and the way that they come off, such that you would look at it and say, "Wow," especially if the one that's smaller is the one that's losing money. Then you might ask the question what's going on.

There are other simple things you could do. I mean there's simple profitability--virtuals, for example, are very easy in the US markets because the expected value of a virtual is zero. And so you can just simply look at the trade of that particular instrument and just see if it's positive or negative on net over the course of, say, a month.

But my best advice would be to think of the universe of things that could be targets for manipulation and think backwards from there. Build whatever screens you're going to build on the basis of the instruments that settle against those prices, and then put your screens on those prices, because that's usually what you have. You may not know all of what other people have in terms of their swaps or other instruments. But you do have the ability to look at the price-making trades, the trades that actually set the price. Think of those from the context of what they could set as reference prices in the market.

Question 8: Going back to Speaker 3's comment earlier about the whole question of the benefit-cost of the regulatory oversight, we seem to have in place now sort of a two-tiered scheme, whereby, at the RTO level at least, we have market monitoring units, that, if they detect a particular concern on market power manipulation, they can tailor a fairly targeted and narrow corrective mechanism. And they also have a feedback mechanism, so that if, within a short time, they see that the fix they put in place has resulted in a substantial reduction in liquidity or trading, or particular problems, they can tweak it. And that process seems to be working reasonably well in most of the markets. And it's had a sufficient degree of confidence, although there is a lot of dissent.

But when you have a mechanism, at the FERC level, at least, where you're defining simultaneous trading in two markets as per se creating a presumption (of manipulation) if you have a non-economic outcome--there are some who would argue that there's been a massive loss in liquidity in trading across all markets. And there is no readily available feedback mechanism for the enforcement arm of FERC to be told by the analytics arm, "You guys may be fixing the problem, but killing the patient." How do you see that process working at FERC, analogizing it to the way the market monitoring mechanisms at the RTO level can work?

Speaker 1: I gave that condominium example earlier for lots of reasons, but one of the most important lessons that comes from that is the role of liquidity in preventing market manipulation. Remember the way I set up the problem: there were only 19 trades on the index prior to my putting my manipulative trade in there. What if there had been 1,000 trades? Well, if there had been 1,000 trades of $500, it wouldn't matter if I put a $100,000 trade in there or not, I wouldn't be able to really bias the price by enough such that I would be able to profitably accrue a leveraged position large enough to make the thing work.

Comment: Delta P, just for the record.

Speaker 1: So the fact is the best defense against market manipulation is liquidity. And I think the concern that has been raised by a couple of the last questions is great. If you have traders who are purposely leaving the market because they are uncertain as to how the rules are going to be applied to them, you're robbing the market of the much-needed liquidity that helps prevent the manipulation from occurring in the first place.

I do want to go on the other slippery slope as well, though. If you don't have any sort of protections against manipulation, well, then in markets where you have constraints binding or in markets where you do have thin liquidity, that means people are going to push these prices around and people will look at these indices and say, "That index doesn't represent the price of true value. I'm not going to trade on that index anymore." What are they going to do? Well, in the housing market, they trade bilaterally. The transactions costs go up as a result, and you lose the benefits of the efficiency of having a market price.

Speaker 2: I don't think that enforcement has anybody that thinks in the way Speaker 1 just talked, and what I hear if I'm around when this worry is voiced, is, "Well, we don't really see that," or, "If financial players leave, what's so big about them anyway, we don't really need them." And so I don't see any feedback mechanism for that to happen. And I don't see any institutional incentives for a feedback mechanism really to be created, because the way that the agency is structured… We talked about RTOs not wanting to have blackouts or high prices. The worst thing, if you're an enforcer, is to be the people who let Bernie Madoff do what he did. So you're going to over enforce in your maiden voyage years, almost necessarily. And you have to answer to Congress, and so you're going to be hyperactive. And the fact that the markets might be hurt is not something you'll be probably looking for, noticing, or attach a lot of importance to if you were to see it. So I think that there's no feedback loop right now at all.

Question 10: As a couple people have said, this is indeed a master class, and it's wonderful that you came out here. But I just wanted to make sure that Speaker 3 and anybody else didn't leave the province thinking that this was the Wild West. [LAUGHTER]

Speaker 2: Don't ruin my dream.

Questioner: The fact is, the Wild West is a US concept--Wyatt Earp and those guys. We (in Canada) had the Northwest Mounted Police. [LAUGHTER] Things were quite orderly.

So one major difference is that the US markets are basically founded on the "just and reasonable" concept, which is a regulatory construct, and the Alberta market and its founding legislation has none of that. So this is not a case of a transition from regulation to a market-based concept.

I think, frankly, what you describe, Speaker 3, when you look at some of the markets, is a quasi-regulatory state. Here in Alberta, with respect to unilateral market power, the framework that's employed is the classical antitrust framework, which focuses on abuse of market power, and the distinction between exercise of market power and abuse is an absolutely important one, because it focuses on exclusionary behavior and restricting the ability of others to compete.

Final comment. One of the differences here is that you have a local based monitor and enforcer and a commission. And I think there are true benefits to having that, as opposed to the FERC, where there are referrals, and there's a certain amount of cooperation, and all that kind of stuff--but do you really get it? If you are poised and watching a particular market, you have some tremendous advantages.

Speaker 3: I appreciate those comments. I have a question. Is there a standard? You said there's no "just and reasonable standard." You apply standard antitrust principles, but you have a market monitoring function. Is there a point at which the law is violated, aside from a conspiracy?

Questioner: Yes.

Comment: You know it when you see it?

Questioner: No, you'll know it if you read our offer behavior enforcement guidelines.

Moderator: Let me thank our three panelists who acted as if they were four. And thank them very much for an excellent dialog and discussion. [APPLAUSE] Thank you.