HARVARD ELECTRICITY POLICY GROUP
EIGHTY-FOURTH PLENARY SESSION

The Watergate Hotel
Washington, DC
THURSDAY AND FRIDAY, OCTOBER 13-14, 2016

Rapporteur's Summary*

Session One.
Transmission Rights and Revenues Redux: Follow the Money

Financial Transmission Rights (FTRs) arose in response to a problem in the design of electricity markets. Under open-access and non-discrimination principles, physical transmission rights could not be guaranteed to match transmission usage and could not provide a means of controlling operation of the system. Efficient market design requires a real-time market built as a bid-based, security-constrained economic dispatch with locational prices. The difference in locational prices includes the effect of transmission congestion and marginal losses. Financial Transmission Rights provide the economic equivalent of the unavailable physical rights in hedging the difference in locational prices. The value of the financial rights incorporates the expected value of these price differences. The allocation of this value accrues to those who pay for the transmission system, either through allocation of Financial Transmission Rights or through the revenues from forward auctions of Financial Transmission Rights. The allocation of auction revenues can occur through the allocation of Auction Revenue Rights (ARRs). Over time, with changing grid conditions, any fixed allocation of rights could slowly disconnect from the total value of congestion and net loss payments. There is increasing concern with the results of these transmission related market elements. Is there a market design disconnect between the allocation of payments for the grid and the value of congestion and losses? Are there problems of market manipulation of or with FTRs? How should the real-time, day-ahead and other forward market use of FTRs be kept consistent with the design principles? How should revenue surpluses or deficits for FTRs be treated? How can we evaluate the performance of FTRs and related markets? What alternative approaches are available for addressing the fundamental design issue in the search for hedges without physical transmission rights?

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

PHONE 617-496-6760 **FAX** 617-495-1635
EMAIL *HEPG@ksg.harvard.edu*
79 John F. Kennedy Street, Box 84
Cambridge, Massachusetts 02138
www.hks.harvard.edu/hepg

Moderator: Welcome everybody. So why are we here talking about FTRs? I think a lot of the markets feel like these are products that are working and working well. Certainly there's staff here from PJM, from New York ISO, MISO, and they feel like they're working well. But in 2015, PJM's *State of the Market* report by the Market Monitor evaluated the FTR/ARR market design as flawed and recommended it be modified to ensure that all congestion revenues are returned to load. In August of this year, the OPC (Office of the People's Counsel) and all the public commission members of PJM issued a resolution that basically took up that call and likewise recommended a market redesign of the ARR/FTR construct so that congestion revenues could be returned to consumers, and the Department of the Market Monitor in CAISO has similarly looked at the market and made similar recommendations. So I think that's the context in terms of trying to address this topic again.

Speaker 1.

So when I was thinking about this and having conversations with people over many months about this general subject, one of the things that concerned me, which may turn out to be a false worry, but nonetheless, one of the things that concerned me is that in some things, like this OPC recommendation, there was a characterization of the nature of the problem and of what we are trying to accomplish with Financial Transmission Rights which seemed to me to be ahistorical. So, it implied that we were trying to accomplish one thing, when in fact, when this was developed, we were trying to accomplished something else. And as we think about policy issues in electricity market design, it just is a fact that the successful market design has a few moving parts, and they all have to fit together, and if the moving parts don't fit together, then the system doesn't work. And you have to keep remembering that every time you start trying to change out one of the gears and replace it with a steamroller, or something like that. So you have to make sure that these pieces together.

So what I'm going to do quickly here is try to step back and think about what we were trying to accomplish. How did we get to the Successful Market Design? Why an independent system operator? Why economic dispatch? Why locational marginal prices? Why Financial Transmission Rights (FTRs)? Why fund FTRs with the the congestion payments, and why is this important? And the answer to the last question is what I just said, which is, these things all fit together. And so you have to make sure that, whatever you're doing, one part doesn't upset this overall design.

As these quotations on my slide show, according to people such as Joe Kelliher and others from the Federal Energy Regulatory Commission, the support for competition in wholesale markets is a clear and continuing national policy, and that's what the Federal Energy Regulatory Commission sees itself as overseeing. And if we want to have a panel on whether or not that's a good idea, that's a different panel. So I'm taking this as the context of what we're trying to accomplish. And the problem is, for those of you who have been around for a while, when you look at the competitive wholesale electricity market structure, and you think about the segments like generation, where you can have competition in entry and all the things that we want, you recognize that there are other parts of the system that are natural monopolies, or pretty close to natural monopolies, and you have to treat them in a different way.

And the characteristic of the electricity system, which made it fundamentally different than other markets, was that in the high voltage grid, there were actually two natural monopolies. One was the wires themselves, in terms of who puts them up, and you only want to have one interconnected grid. You don't want to have two of them overlaying each other. And then, secondly, you have this problem of the coordination of short term markets. So the system operator functions span lots of transmission ownership areas, and we get the regional transmission organizations and independent system operators that we now have.

This was not a widely accepted view at the start of this conversation. I actually have a copy of this campaign pin ("Poolco" with a line through it) at home, which I was given by Enron. [LAUGHTER] And for those who want to hear the battle stories, I'm happy to tell you about the various wars. But this was not easily accepted, and in fact, most people forget that the first year of operation was a complete disaster in PJM. And that's because they didn't adopt that model. They adopted the Enron model, which was the "stop poolco" movement, and that turned out to be a big mistake, which we then fixed later on.

The centerpiece of that conversation was this whole debate about transmission capacity definitions. On the left of this slide, we have a diagram of the "contract path" fiction—the idea that we can follow the electrons through the wires and go from those sources to loads, and we know what we're doing. The idea that we could have physical rights, essentially, and run the system that way. The reality is, the power goes everywhere. That's what the center diagram illustrates--we have electricity going on every particular path. That "parallel flows" problem is a very complicated problem. In principle, you could ask market participants to go get rights on every path for every transaction, but this would be completely overwhelming. So it's just impossible in practice to do that. And then on the right, you have the diagram which shows the resolution, which I'm going to summarize, in which the flows are still there, but they're implicit. The problem of coordinating flows is handled by the system operations, and we get these points to point definitions of Financial Transmission Rights that we're now familiar with.

This is not an easy conversation. The Federal Energy Regulatory Commission in Order 888 explained this dilemma quite clearly in its analysis and said that the contract path was a fiction, and it actually didn't work. And then later on it said, something like, "Never mind, because we can't figure out what else to do. It's too hard, so we're going to do it anyhow." And so that took a long time to sort itself out, but we finally did kind of sort that out.

I won't go through all of the painful detail. But the essential problem associated with these network effects and these interactions is that there are no property rights in the transmission grid in the sense of controlling the flow. So there's no workable system governing use of the transmission system that would support a fully decentralized electricity market. There's no definition of available transmission capacity. We went around and around and around with that conversation in the '90s to try to work this out, but for conceptual reasons, it obviously depends on how you're using the system. You can't define that independently. And since we were trying to define it independently so we could figure out how to use this system, this was just hopeless, and we had to do something else.

It turns out there's no separation of transmission pricing in the spot market. So, unlike what was assumed in the division between the California Power Exchange and the CAISO, which created its own set of problems which we are all familiar with, you can't actually do that. You can't set up the transmission separate from the spot market. Once you have determined the dispatch, you've determined the use of the transmission system. Once you've determined the use of the transmission system, you determine the dispatch. There's no independence in that. There are no degrees of freedom, so they have to be solved as the same problem at the same time, and there's basically no escape from these network externality problems. And this is a first order kind of problem, which is fundamental to the very existence of some model for having an electricity market.

On the economic dispatch side, these are questions which I posed back then and today, which were designed so that the answers were always yes. So, should the system operator be allowed to offer economic dispatch service for some plants? Well, if we say no, then what we want is a policy of uneconomic dispatch, and that didn't seem like such a great idea. Should the system operator apply marginal cost prices for power provided through the dispatch? Well, the marginal cost prices, the LMPs, as we now call them, often are the only prices that support this economic dispatch solution. And if you use any other prices, by definition, it means that people have incentives not to follow the dispatch. So you create this conundrum if you don't use those. So the natural thing is to say, yes. And then, should generators and customers be allowed to participate in the economic dispatch offered by the system operator? You don't have to mandate it. This was the bilateral versus poolco debate. But if you make it a choice, the answer is yes.

Then you end up with the basics of a successful market design. You get economic dispatch. This chart illustrates the way economists look at economic dispatch. If you stack up the costs of the generators, that gives you a supply curve, and you've got demand curves, and you have market clearing prices, and everything works just fine, in principle, in the short run electricity market.

The difficulty was the network story and the interaction across all of those networks, but there's a straightforward generalization of the same ideas that was worked out by Fred Schweppe and his crowd back in the 1980s at MIT. And you get this economic equilibrium equivalent to economic dispatch. You get locational prices. And, happily, the prices for transmission in that system and the spot market prices are just the difference in the price between the two locations where you're transmitting power in this point-to-point representation. So it all works.

I promised several of the participants here that there would be no equations today. [LAUGHTER] So I had to delete the next four charts. But in electricity, it was a big revolution. Once you had this spot market, and you had a spot market reference price, then you could have a long-term contract, and then you actually did all your transactions relative to the spot market, and you paid, if the price was higher than the contract price, or you got paid, if it was lower. And so you can reproduce, through a financial contract in the forward market, what people thought of as physical rights, but you could do it in a way that was compatible with the network externalities and issues in the electricity grid. So that's why the short run is so important, and that allows you to do the forward contracting to get all of the incentives that we wanted to have in efficient markets. And you can have long-term power contracts that hedge those prices.

But the problem is with the Schweppe story is that you get these volatile prices at every location. And the difference between the prices between locations is the difference between highly volatile things that are not necessarily correlated. So that's highly volatile. So now you have a problem of, if you want to have a long-term contract at Point C, but with a customer at Point A, you have to worry not only about what the price is at one of those two points, but you also have to worry about this differential. And that's where Financial Transmission Rights came into the story. You can construct a set of Financial Transmission Rights, which allow people to collect the difference between those locational prices, and that provides the perfect hedge against this sort of variation in the basis risks. And now that allows you to contract anywhere to anywhere, and you can do what we wanted to do in the first place, with physical rights, but we couldn't do it with physical rights, because there was no way to do it.

I remember the first time we discussed this, people thought we were crazy when we said this, but now everybody understands what the principles are, and it has the added advantage that if the allocation of the Financial Transmission Rights is simultaneously feasible in the actual grid that you're using, then it turns out that no matter what the dispatch, no matter what prices come up in any short run market that you're looking at, the revenues that will come into that system, which we're going to refer to here as the congestion payments or congestion costs, will always be greater than or equal to the obligations under the Financial Transmission Rights. So you can hedge the individual price differences. In aggregate you get this revenue adequacy characteristic, which is an important feature of this, and one of the issues we're going to be talking about today. And this is true for Auction Revenue Rights.

A problem we ran into was, how do you get started in this process? How do you take your rights to the grid and somehow allocate them amongst the users of the grid? There are different solutions that you could imagine, but the Auction Revenue Rights story is one way to do that. And then, if they are simultaneously feasible, they'll be revenue adequate. And there may be surplus revenue, which you then have to distribute. If the Auction Revenue Rights are not simultaneously feasible, which they often would not be, given the way they were defined, then you had to scale them back, and they didn't satisfy this. But that wasn't a problem, because the only issue that you were really concerned about here was that the ones that you sold, not the ones that you initially allocated, had to be simultaneously feasible. And that's handled with the FTRs.

This story works for dealing with the real-time market. It also works for dealing with the day ahead market, if you have a day ahead market. Then you have to settle the Financial Transmission Rights against the day ahead prices, as opposed to the real-time prices. And then there's a separate set of day ahead schedules that are determined in the day ahead market that eventually are like reconfiguring all the FTRs, but you essentially sell the FTRs, and then you have these new schedules. And that produces a set of contracts that apply to real time. And all the revenue adequacy story and assumptions and properties apply to that problem. And those are separable problems.

So what happens in the real time is not dependent on what is going on with the FTR. Those are completely separate issues. And you can extend this to some analyses of investment efficiency. If you're expanding or contracting the grid, and you follow the feasibility rule of making sure that everything's simultaneously feasible after you got finished, then you can say, today, "We're going to award these FTRs. We're going to follow these rules. And ten years from now, at ten o'clock in the morning, when we do the economic dispatch, it will turn out that we're revenue adequate." And so that's the kind of thing which was a revelation at the time it was first revealed, because you couldn't do this with physical rights. And it is very important for market efficiency in the long run.

This slide shows the definition of FTRs that came from a recent FERC decision. In short, FTRs are long term contracts that hedge spot market prices and support investment. Physical transmission rights are not available. We need to hedge both the price at locations and the difference in those locational prices. There's a separate issue of real time balancing congestion, which is not affected by the FTRs but follows the same principles. And the revenue adequacy property points to congestion payments as the natural source of funding for Financial Transmission Rights.

Congestion payments are the only source of revenue I can even think of that has this revenue adequacy property. Now, in principle, you could mail the congestion payments to Ireland, and you could make the transmission operators fund the FTRs some other way. But then they would have to come up with the money, and then charge people, and you wouldn't get this natural hedging and all of that kind of stuff. So you would just be throwing away the inherent correlation that's actually embedded in the short-term dispatch that we're taking advantage of in this particular way of funding it. So any other use of the congestion payments would undermine the essential market design for short run and long run efficiency.

With FTRs, you get a structure where not only can you have long term power contracts between generators and customers, but you also have these long-term transmission contracts, which are the FTRs, and then the short-term operations of the power pool. And this all fits together. This has been debated many, many times, as you know.

This slide is my graphic where I keep crossing out the different FERC proceedings related to market design, because I keep trying to send the message that this is not going to change. You can have another proceeding and hope. You can ask the question in a different way and hope to get a different answer, but it's not going to happen. So we have to just face up to it, that this is the way to do it. This is the only model that can meet the test of open access and non-discrimination. Anything else, anything that upsets this design, will unravel the whole electricity market design. And I want to emphasize that. This is not just a good way to do it. It's not like, "Oh, well, we could have done it this way. We could have done it that way. We could have flipped a coin." No. This is the only way to do it, if you want to meet the test of open access, non-discrimination and economic efficiency. Now, if you want to have an uneconomic solution, then you have a lot more flexibility. [LAUGHTER]

And we've learned this the hard way. I won't go through all the paths here. Most of you have lived them. Order 888, I think, made a conceptual mistake, which was to say, this doesn't work in theory, but it might work in practice. And what we found out is that it didn't work in practice, either. And so now we have gone all the way around, where all of the regional transmission organizations use this basic Successful Market Design: bid based, security constrained economic dispatch with locational prices and Financial Transmission Rights. It's important. Thank you.

Speaker 2.
It's an honor to be here, and especially an honor to be talking electricity market policy with Bill Hogan. He was an idol of mine in graduate school, and one of the main reasons for that was that he had this beautiful, important theory that he came up with and that he's talked about,

which is that if the FTR model is exactly the same as as all 8,760 different day ahead market models over the course of a year, that the congestion rents collected in the day ahead market will be sufficient to cover the obligations to pay out on those FTR contracts. And it's an important theory. And one of the implications of that is that under this precise, specific theoretical scenario, where the FTR model is exactly equal to the day ahead market models, that you can kind of view FTRs as being the rights to congestion rents under this specific case. So the simple point I'm going to try to make today is just that FTRs are not the rights to congestion rents. And that's an important point.

I think the idea that FTRs are the rights to congestion rents has been misinterpreted. It's used as the genesis for the arguments that rate payers have to be the ones that auction off FTRs. Right? And the argument goes that if FTRs are the rights to the congestion rents, then the rate payers, the people who receive the congestion rents, have to be the ones to auction off the FTRs. But that's not true. FTRs are not the rights to congestion rents. Anybody can auction off these FTRs. Anybody can sell FTRs. FTRs are just financial swaps.

So to make this point, that FTRs are nt the rights to day ahead market congestion rents, I want to look at how money flows to and from the entities that pay for the transmission assets. And so you can kind of arrange these money flows however you want to make your point. I want to look at the money flows from the perspective of the monetary transactions that actually take place, the monetary transactions that the rate payers are actually involved in.

So let's look at the monetary transaction that happens with congestion rent and FTRs. OK? This is the first kind of fundamental transaction. The first element to this is that rate payers pay the transmission access charge. Rate payers pay a fee. In California, it's per megawatt hour. They pay a fee to cover the capital costs of the transmission and a rate of return on those costs. I didn't put that in this slide, because I intended this to be the FTR balancing account. So first you have rate payers paying for the transmission, and then, in exchange, they get the congestion rents. The ratepayers get the rights to the revenues that are generated by those transmission assets. Right? The revenues generated by the transmission assets are the congestion rents that come from the day ahead market. Those are the rate payers. Those belong to the people who pay for this asset. They get the revenues. That's one transaction. If there weren't any other transactions in ISOs, then those congestion rents, those revenues, would be distributed. Currently, if we didn't do any FTRs, those would be distributed I think by metered load, and by exports. It would be actually be distributed to the people who pay for the transmission on a per megawatt hour usage basis.

So now we go to the next step. The next transaction is the FTR allocation transaction. So, under the FTR allocation, certain sets of rate payers, certain sets of people who paid for the transmission assets, they receive a financial contract. That financial contract, the FTR, gives them the right to receive the revenues in the day ahead market from the difference in the day ahead market LMPs between the source and sink for all 8,760 hours of the year that this FTR allocation contract is valid for. These rate payers receive payments from allocated FTRs.

The rate payers fund those contracts. Right? Those payments come of this FTR balancing account. So those contracts are paid for by rate payers. So, ultimately, from the perspective of the people who pay for the transmission, this transaction is offsetting. Right? I'm not here today to talk about the allocation process. We don't have any issue with that. I think the theory that if the FTR model is the same as the day ahead market model, then the congestion rents are sufficient to pay these FTRs is a powerful theory, because it shows that the FTR allocation is a legitimate, efficient way to distribute the congestion rents. OK? But it still does not mean that these allocated FTRs are the rights to the congestion rents. It's a monetary transaction. It's just that the theory implies that the congestion rates can be used to fund this transaction.

So now lets' move on to the transaction that is of concern—auction revenues and payments to auctions FTRs. This is where I think the Standard Market Design enters the realm of market design flaw. With FTR auctions, ISOs are auctioning off fixed for floating financial swaps on behalf of rate payers. Right? And that is what an FTR is. The rate payers auction off FTRs for a fixed lump sum price--they receive the auction revenues, fixed value. In exchange, they are obligated to pay out the floating side of this contract. They're obligated to pay out this uncertain risky price difference, over all 720 hours in a month, of the realization of the point to point price differences between the source and sink in the day ahead market. Right? That's the underlying transaction of an FTR. It's a fixed for floating financial swap.

So, from the perspective of rate payer, this financial swap is a good thing to sell if the auction revenue, the money they receive, is going to exceed their expected obligation to pay out on the floating side of the swap. You can bring in some issues with the risk aversion profile, but, essentially, if the auction revenues are going to be higher than what they expect to pay out on this financial swap, then it's a good deal.

All right, so if you're a rate payer, there are two questions to ask when thinking about engaging in this financial swap. The first one is, what price should I sell the swap for? So, currently, under the FTR auction design, ISOs are auctioning off these financial swaps on behalf of rate payers at a zero dollar reservation price. So if not enough bids go into the FTR auction, or if the bids aren't priced highly enough, then this auction will result in rate payers having to sell risky financial swaps for significantly less money than they can expect their obligation to be to pay out on these swaps. The second question you have if you're a rate payer is, what quantity of these financial swaps should I sell? And it's with respect to this question of quantity that this false concept that FTRs are the rights to the congestion rents is particularly insidious, and kind of leads to some flawed market design.

So, after the allocated FTR transactions, there are going to be congestion rents left. Those congestion rents are distributed to rate payers. Right? This other transaction, this FTR auction transaction, is a separate transaction on top of that. It's a transaction on top of that, where rate payers are selling financial swaps.

To make it an important point that's a bit of a side point, there is Speaker 1's beautiful theory that if the FTR market model is the same as the day ahead market model, that the congestion rents will be able to cover the obligation to pay out. There's an important point here, though, and it's also important in the context of later on in figuring out why there isn't sufficient competition. It's that the FTR model can never equal the day ahead market models. Right? So this congestion rent, this revenue stream that rate payers receive, it's a revenue stream that's correlated to the rate payer's obligation to pay out on these financial swaps. So, just because rate payers receive a revenue stream which is correlated with the obligation to pay out on the floating side of a risky fixed-floating swap, does that mean that they should have to auction off these financial swaps? No. Rate payers don't have market power simply because they receive this congestion rent revenue stream, or because they have a revenue stream that's correlated with the payouts on the floating side of a fixed for float swap. But rate payers don't have any market power. They're not the only ones who can sell the swap. Anyone can sell the swap. Right?

So, if you're a rate payer, it doesn't matter to you, in terms of deciding whether selling this financial swap a good idea, it doesn't matter to you if the congestion rents are sufficient to cover your expected payouts on the floating side of the swap. All you care about is, are the auction revenues you receive from selling this at least as big as your obligation to pay out? So, for example, imagine the ISO is kind of a bit conservative with how many swaps it's going to sell, and so the obligation to pay out on FTRs is clearly less than the congestion rents. So we're revenue adequate. From the rate payer's perspective, that doesn't matter. Sure, they have, their congestion rent revenue stream is sufficient to pay out on these swaps, but the revenue they're receiving from the auction side is less than their obligation to pay out. Selling the swaps is a bad idea. Revenue adequacy isn't something that is a concern right there in this situation.

Here's a another scenario that we see in the California, which is one where the ISO has auctioned off a whole lot of FTR rights. So now the obligation to pay out on the financial swaps is a lot larger than the congestion rents. But, again, what matters here is that the auction revenue is a lot less than the rate payer's obligation to pay. So, again, it's a bad deal. Rate payers are losing money on this. But, again, even in this scenario, where a whole lot of FTRs have been sold, a whole lot of these financial swaps have been sold, if there was sufficient competition, if enough people came in and bid in sufficient quantity and bid high enough so that the auction revenues were larger than the expected obligation to pay, then selling these swaps would be a good idea. When it comes to the auctioning off of these financial swaps, revenue adequacy isn't something that is relevant.

So, given that, the realty that we've seen in California is that auction revenues have been low compared to the obligation to pay out. Rate payers have lost huge amounts of money under the current design, which forces rate payers to auction off these FTR financial swaps at a zero dollar reservation price, in a quantity representative of the amount of transmission capacity that the ISO expects to be available. So our proposal is that rate payers shouldn't be forced to auction off these swaps. Generators can still get their hedges. Anyone can sell these financial swaps. Rate payers don't have to be the ones to sell them. So, still do the allocation process, but then, when you run the auction, set the limits equal to the flows of each constraint that have come out of the allocation process, so that any time a swap is sold, it's between a willing buyer and seller, instead of being subsidized by rate payers. Thank you.

Question: Unfortunately, you don't come from America's favorite RTO. And in PJM you don't have to auction off your FTRs, if you're load. You can hold on to them, and we have that convoluted ARR/FTR construct. Could you give a two-minute overview of how it works in California? Because I'm not quite sure I followed.

Speaker 2: Yes, sorry. It does end up being similar in practice, I guess, but in California there's an allocation process to load serving entities that serve load. They get allocated FTRs. So there's a process by which they are awarded their FTRs. And when that process is run, the simultaneous feasibility test is run, so that simultaneous feasibility is assured, given that the FTR model was the same as the day ahead market models. And then after that, the auction takes place. Right?

So say you have one transmission line. It's 100 megawatts. In the allocation process, only 80 megawatts of that capacity get used up. The FTR auction is then run, where the limit on a path is 100 megawatts. So an extra 20 megawatts of capacity is, in a sense, auctioned off. So that's the model. So you have this extra amount of financial swap, FTR financial swaps, that are auctioned off, representative of that extra 20 megawatts of capacity.

Question: So it seems to me there is a slight difference, because in PJM, my understanding is the ARRs represent all of the…no, someone is shaking his head. I thought that PJM didn't actually hold back excess, except maybe related to long term FTRs? Am I getting too technical? Just, it would be helpful for me to understand, I don't know, if it doesn't help other people, we can take it offline.

Comment: I'll talk about that a little bit when I talk about the PJM side, but I don't think that's an accurate characterization.

Question: So can you self-schedule in California? Can you self-schedule, and keep your FTRs? Or self-schedule to keep the revenue on the 80% path you were awarded?

Speaker 2: Exactly. I mean, essentially, I guess our model would be as if everyone who gets allocated self-schedules, if I'm understanding the ARRs correctly. They have the FTRs, and then they could choose to sell them back in the auction.

Question: Just a follow on from what the previous questioner was saying. Are you arguing that the way they allocate the FTRs creates this problem? Or the revenue rights to the auction? If you just allocated FTRs, then the problem goes away.

Speaker 2: Yes, exactly.

Questioner: Just file.

Speaker 2: Yes.

Speaker 3.

Thank you. It's always an honor to be here with this group. I agree with a lot of what Speaker 1 said. What's going to be interesting for all of us, me particularly, is to see exactly where we diverge, because we clearly diverge somewhere. But Speaker 1's support for markets I absolutely agree with. The notion about nodal markets and all the rest of that, of course, I agree, and Speaker 1 has been, obviously, a super strong supporter of markets. And I agree on all the fundamentals.

But I also agree that it's appropriate to talk a bit about history. And I think I'm going to draw some slightly different lessons from history. So, again, it's up to you to explain to me how we're differing somewhere.

So, prior to markets, in the olden days, 1998 and before, if you wanted access to cheap generation from outside your zone, you got a firm point to point transmission contract. You owned those rights. You paid for them, and you got the power. If you didn't want to pay for congestion, you bought power from the utility through a long-term contract, and you got access to cheap power. You paid for the transmission. So that was the old days, the physical days, when you actually had contracts and point to point, and all that stuff was the way that things were organized. Unfortunately, some of it still continues, but that's another matter.

The introduction of fully nodal markets, (we'll skip over the 1998 debacle) was April 1, 1999. LMP congestion pricing. So suddenly contract paths are not relevant. As Speaker 1pointed out very clearly, back then and now, there's no such thing, really, as a contract path in a nodal market. You can't tell where your power is flowing from. It depends on the distribution and generation, depends on least cost, economic, security constrained dispatch. Your power could be coming from Chicago. It could be coming from Del Mar. It could be coming from anywhere. We're not color coding the megawatt hours. Who knows where they come from. But what matters is, there's congestion. So the prices at every node, as Speaker 1 pointed out, reflect the marginal cost of generation, subject to security constraints, that is, subject to the line limits on the transmission system. Power prices reflected and do reflect the realities of the physical system and the marginal cost of the system and the available transmission capability, transmission impedances, the marginal cost of generation. But what nodal pricing meant is that everyone in a constrained area pays the same price, regardless of how much import capability there is. So you could be in an area where there's 100 megawatts of load, and 99 megawatts of transmission import capability. And if the local price is $200, that's what you're going to pay, even if the cost of power from outside the area is five dollars. So you're going to pay that higher price. The difference between what you pay as load in that constrained area and what the generator outside receives is congestion revenue. It's the difference between what load pays and generation receives. It's money that is not actually paid to anybody, but which load pays, and I'm suggesting load has the right to receive that money back, because load is paying for the transmission system and that makes delivery of that cheaper power possible.

So the introduction of FTRs, as Speaker 1 correctly described, was the way to address that issue in a nodal market. When FTRs were first introduced in 1999, that was before there was a day ahead market, so the idea of FTRs couldn't possibly have accounted for or even thought about day ahead markets. Their goal and their result was to return all those congestion revenues to load. Now, one of the mistakes I think that was made at that point was that FTRs were assigned to load based on generation to load paths. Or, as we used to call them, contract paths. That was a fundamental logical flaw which, I think, has led to many of the difficulties we're in. And I'll try to explain why I think that's true. But even if you got the gen to load assignments wrong, even if you simply missed it entirely, load got the FTR revenue, got the congestion revenues back, because at the end of the month, the end of the year, excess revenues were always spread back to the holders of the FTRs. The FTR holders were load. Therefore, they got it all back. Now, you may have misallocated it, and I'm sure it was misallocated, and I'm sure the misallocation got worse as time went on. But, nonetheless, load got it all back.

One of the interesting things about the current situation is, we're continuing to use the 1998 gen to load paths to assign ARRs to load, which is, on its face, not very sensible.

So in 2000, I think it was June 1, 2000, the day ahead market was added. So now we have day ahead plus real time, and we still have the same assignment of generation to load paths. But we continue to have all congestion revenue being returned to load. FTRs are allocated to load based on those gen to load paths, and whether they use the entire system or not, again, doesn't matter, because all congestion revenues came back to load again, because the excess was spread to FTR holders. There was no leakage. There might have been allocation issues, again, but the total congestion revenues are returned to load under the original FTR design, even with a day ahead market.

Someone will have to correct me if I'm wrong about the year that ARRs were introduced. I think it was 2003. Yes? OK. So let's say it was 2003, around then. ARRs are introduced. So now you had a split. You had a redesign of the FTR model, and you separated FTRs into ARRs and FTRs, ARRs being Auction Revenue Rights, and FTRs being Financial Transmission Rights. So now the generation to load paths actually became relevant. They actually made a difference in the outcome of all this, because the ARRs continued to be assigned to load based on gen to load paths, from the original PJM footprint from the 1998 gen to load paths, even when generators were retired, or even when they really were not relevant to any actual power flows. So the gen to load paths now defined, and for the first time limited, the flow of congestion revenues back to load, because the excess no longer goes back to the holders of ARRs. The introduction of ARRs created an artificial split between congestion on the gen to load paths and the total congestion. And that's really, I think, the nub of where our current difficulties began. It's a combination of the gen to load paths and the separation of Auction Revenue Rights and Financial Transmission Rights.

Another key point about the FTRs is that (and this is what I was talking about before) the FTRs, the total capability of the system allocated to FTRs, could exceed and has exceeded the total capability assigned to ARR holders. So there is an additional leakage in total congestion revenues as a result of that. So once the FTR holders got that difference, that was an incentive for FTR holders to redefine the terms of the trade to get a larger share, and we've seen that occurring.

If PJM had continued with the original FTR system, the current FTR issues simply wouldn't have existed. Revenue adequacy could not have been an issue. All the congestion revenues would have continued to have been returned to load, no more, no less. When congestion's high, you get it all. When it's low, you still get it all. And just for amusement, as something to look at besides me and my name, here's total congestion revenues over the over the last seven or eight years.

So there was a hedge, but the hedge was for load, and it was to cover the fact that they were paying congestion revenues; that is, they were paying more for generation than generation was receiving.

So the result, I think, has been to incorrectly define the products, ARRs and FTRs. The split created the incorrect idea that load should pay for the transmission system, that load should pay all the congestion revenues, and that load should now pay for a hedge the financial participants can turn around and sell back to them, which appears to be one of the claimed benefits of FTRs. Most of the complexities of the debate about FTRs, and I have to admit the complexities of the debate about FTRs sometimes are nearly overwhelming, derive from those incorrect product definitions.

My basic point here is that there's no reason not to return to the fundamental notion. There's no reason not to return all congestion to load. And there's no reason, if you do that, not to permit load to continue to engage in selling the swap. If load willingly enters into a bad swap, that's load's problem. If load wants to sell their right to congestion revenues for a fixed payment, that's fine, as long as they're doing it voluntarily and know the terms of the transaction. So, again, there's no reason not to return to that fundamental notion of returning all the congestion revenues to load, and if you want to create an auction in which load sells those rights to financial participants, that's fine.

I just wanted to go through just a few slides here, just to illustrate some of this. These are all from the *State of the Market* report, as is everything I ever say. So if you want to see more about it, look at the *State of the Market* report. So you can see that congestion changes pretty significantly, but congestion is somewhere in the vicinity these days of a billion dollars. So we're talking about real money when we're talking about FTRs, and we're talking about assignment of congestion revenues. When it comes to FTR auction ownership, if you look at the financial row all the way over to the right, financial participants own about 2/3 of all FTRs. Just as a fact, physical participants are load serving entities and generation owners. And FTRs have been profitable year after year, regardless of whether there was underfunding or overfunding, regardless of the level of net revenues. And the level of profits is really the difference between the price paid for FTRs and the congestion revenues. So to the extent that profits remain fairly high, it's a suggestion that for some reason FTR buyers are not continuing to bid the price of FTRs up to the point where the costs and profits are reduced close to zero, which is what you'd expect without barriers to entry in a competitive FTR market. Everybody knows the story. But there's been funding and underfunding.

Bu the whole entire definition of this turns on, again, an incorrect definition of what full funding means. And it's just arbitrarily defined to be day ahead congestion. Of course, day ahead congestion is not all of congestion. Total congestion occurs in both day ahead and balancing markets. But the whole notion of underfunding or revenue inadequacy is a result of what I think, again, is an arbitrary distinction between day ahead and balancing congestion.

This slide shows some numbers related to the FTR payout ratio in PJM. So PJM had a problem here in the years 2010/11, 2011/12, 2012/13, 2013/14—it allegedly had a problem. That is, the revenues were less than the day ahead target allocation. So PJM solved that by simply assigning fewer ARRs to load. They reduced the assignment of ARRs to load in 14/15 by about 85%. And, lo and behold, revenue adequacy returned.

And kind of the flip side of the profitability metric is that the total proportion of congestion revenues returned to load has been less than 100% from 2011/12 through 2015/16. And the numbers vary from very high number in 2011/12 to a very low number in 2013/14. And, yes, in PJM, ARR holders can self-schedule. They can choose to take the FTR itself, get the actual FTR revenues, and you can see that their behavior has changed fairly regularly over time, in terms of reducing the amount of FTRs they retain as ARRs. Thank you. I look forward to the discussion.

Question: When you say, "return to load," if we're talking about property rights here, what is that property right limited by? I mean, all load, everywhere? How much? What load? 1998 load? 2016 load? You know, which and where?

Speaker 3: So it's real time load, hour by hour. So the congestion revenues, whatever they are, high, low, zero, would be returned on an ex-post basis based on what load is actually paying. So it's not an allocation, and it's not using some historical numbers. It's using actual incurred congestion. That is the actual difference between what load pays and generation receives, hour by hour, and then assign that back, allocate that to the load that paid it.

Question: And that should be defined by the 1998 generation to load path?

Speaker 3: No, absolutely not. I think that gen to load paths are irrelevant. It's based on the actual congestion paid. The point is, we're in a nodal market. We're in a network market. We're not in a contract path market. Congestion is defined by what you actually pay. So it doesn't matter where the power's coming from. All that matters is that, for whatever reason, there's a constraint. There's cheaper power outside, more expensive power inside, and you end up paying congestion. So this is trying to get away from all those historical approaches to allocation, and simply using it on an actual basis. You actually pay a dollar, you get a dollar back. And it is possible to do that. It's not all that hard to do it.

Question: But prior to the ARRs being introduced, there were FTRs. It wasn't that they would just take the congestion revenues and allocate them to load. There was a monthly FTR auction, and market participants could make bilateral contracts between generators and load serving entities, and they reallocated FTRs if there was transfer capability.

Speaker 3: Yes. Absolutely, there were FTRs, and that's my point. So, FTRs were being assigned to load. Now, to the extent that PJM sold off what they regarded as excess, it's really the same issue that arises now. There's no such thing as excess. So you're right. Early on, there was actually a gray market in FTRs, even among load serving entities. There was a little bit of extra FTR megawatts sold off. But there were only FTRs to begin with, prior to the 2003 introduction of ARRs.

Question: And why did they introduce them, in 2003?

Speaker 3: That's a very good question. I don't know the answer.

Question: Did it have anything to do with the fact that PJM was introducing a one year planning year auction of the FTRs and basically --

Speaker 3: I don't know what the stated rationale was, but what I can tell you is, I don't think there was a good reason.

Question: Does this problem exist if all ARR holders self-schedule all of their ARRs as FTRs?

Speaker 3: Yes.

Questioner: OK. And why is that? If you could just go into that.

Speaker 3: Sure, absolutely. It's a good question. It's a key question. So, basically, the question is, why is there a leakage in the total congestion revenues? Why is it that all congestion revenues do not go back to load, at least potentially? And is load simply being dumb, and that's why there's a shortfall? So, first of all, if it were the case that all congestion revenues were assigned to load via ARRs, load could still receive less than 100% because they decided, for whatever reason, to trade for a fixed payment, which was less than total congestion revenues. So, yes, that could happen, and that has happened, to some extent, but that's not the entirety of the explanation. The other part of it is that "excess capacity." Some capacity is being sold to FTR purchasers and it's not being assigned to ARR holders. And as one metric of that, there is what's called the "excess revenue" from the

FTR auction. In theory, that ought to go to ARR holders. Instead, it goes back to FTR holders.

Question: Would that problem go away if PJM or whichever RTO allocated more ARRs than they are currently doing?

Speaker 3: Yes. I mean, if ARRs are assigned based on actual congestion that occurred, then that would be fine. Not using gen to load paths, not using 1998 or 2016 gen to load pass, but using actual congestion, yes.

Quetion: Can you define "load" in this situation? Let's say there are exports into New York. There's purchases or sales going into the New York pool, for example. Does that constitute "load," for this purpose?

Speaker 3: Clearly, there are some complexities in doing that. But "load" is load serving entities that are paying for the firm transmission system. So they're paying for transmission. So anyone who's paying for firm transmission qualifies.

Questioner: Within PJM, or outside?

Speaker 3: Yep.

Questioner: It doesn't matter.

Question: Let me rephrase an earlier question. What if we actually had the ARRs allocated based on current usage today? Does that solve the problem?

Speaker 3: No. So, 2016 gen to load paths are still gen to load paths. They're not reflective of actual flows on the system. And they can't be. Right? You don't know how ConEd load is being served. You don't know how Dominion load is being served. It depends on the actual nature of the system at the moment in time. What are marginal costs? What are transmission impedances? What are outages? All the rest of it. You cannot do that correctly. That's the whole point about contract paths. They're not correct.

Questioner: I wasn't suggestion contract path.

Speaker 3: I know, sorry. I didn't mean to imply that you were.

Questioner: Just, again, to clarify, your problem is with the way the rights are allocated in the first place? Not the auction itself?

Speaker 3: I think so. So, if all congestion revenues are assigned to ARRs, and then ARRs chose to have an auction to sell those off for a fixed payment, that would be fine, yes.

Questioner: Do you mean like before the fact, or after the fact?

Speaker 3: Well, it would be better for load to sell after the fact, obviously, but I was thinking before the fact.

Question: So, I've heard you say this before, and I think I understand everything. But where I struggle is trying to figure out where your proposal fits in with locational competition for, let's say, load serving entities that are competing to serve load on a long-term basis at a zone within PJM. So how does what you propose support that locational competition?

Speaker 3: I think it should very much support it. In PJM, where there is retail competition, the more the merrier, obviously, in terms of load serving entities. If they know that they are going to get back the congestion revenues they pay, then they can factor that into the prices they offer. Now, if they're worried about volatility, of course, there's volatility. Markets have volatility. That's the nature of the markets. That's one of the good things about markets. If they're worried about that, then they can do a floating for fixed trade, if they want. They can get rid of the floating risk, and they can take a fixed payment from somebody who wants to pay them for it. So it gives them the option. They have the right to the revenue. It gives them the option to deal with it however they want. I hope I keep saying the same thing all the time. Tell me if I don't. I try to be boringly consistent. I don't always succeed.

Speaker 4

I think the topic so far has potentially been distorted a little bit by some of the terminology used. I think it's important to reflect on the concept of congestion rents, and maybe the term "congestion rents" could lead to a wrong impression. The LMP that customers pay is the right price. It is the price determined by the marginal generation that is serving the load. I think one of the implications, potentially, of what Speaker 3 has just suggested is that a potential outcome would essentially be a refund of the congestion costs. Right? And that essentially unwinds LMP entirely. So that's one of the kind of side effects that would be problematic from a policy perspective.

The other element that I think is important to understand is that, in both of the potential ideas here, there is an unwinding, essentially a restriction or a preclusion, potentially an elimination, of the ability for anybody to buy an FTR. The FTRs would just be allocated, and if there were secondary transactions, that would be fine. But there would be no further ability for third parties to use the transmission system.

So we get back to the fundamental problem that Speaker 1 illustrated, which is, how do we actually allow open access into the system? How do we answer the question about who gets to use the transmission system? And in this context, I would like to just provide a market based perspective on what Speaker 1 has outlined as a really good idea, or as the only way to do it, from a theoretical perspective. I want to underpin this, and to say that it's actually working and discuss the market based data related to that.

Very quickly, I should just mention that there are some disclaimers here. I'm not soliciting any business. I'm not providing any advice for investment, etc. But, basically, as I've thought about the discussion here about the merits of the FTR option, it sounds a bit like talking about the merits of democracy. And, really, there are no clear alternatives, because you really want to have open access, meaning, anyone should be able to buy excess capacity that's not used on the transmission system. You want to have it be free and open. Now, perhaps there are issues with that. People have talked about the problems with democracy. But in reality, I think I'm quoting Churchill here, it's the "worst form of government [in some contexts] except for all the other forms that have been tried."

Clearly, part of the challenge we face here in today is discussing alternatives. What alternatives, really, are there? The alternatives that we've heard so far are all variations on a restricted market. For example, a restriction on who can buy an FTR, or a restriction on how an FTR can be sold, or essentially an elimination altogether of that, which is, essentially, "Let's get rid of the FTR auction and just have an allocation process." Restriction or elimination of property rights sort of runs counter to economic theory for maximizing value. And I will argue today that the current structure of the FTR option is in the best interest... It promotes a vibrant wholesale market. And it benefits end use customers.

Finally, I want to mention a little about the congestion offset metric that Speaker 3 put forward. I'd say it's an unreliable measure of auction function, and certainly not necessarily dispositive of the question of whether it is desirable for the end use customer.

On the case for auctions, I will show data today that PJM auctions are competitive. For example, there is very large participation in the auctions. Volumes are increasing. I show here some data that shows that auction revenues track congestion over time. There are clearly outlier years, and I want to discuss that in more detail.

Now, the current auction structure really does exhibit the desired competitive market outcomes, as outlined in the theory behind all of this. First of all, the FTR does behave just like it should. In other words, the financial rights are retained at the ISO and able to be used for redispatch on an efficient basis in the real time. But the hedge against the risk is really available to the market, available for third party transactions, available for promoting competitive wholesale, competitive supply. This third-party market is actually really critical to the future policy objectives of serving the customer in a just and reasonable manner over time. And, in that context, the auction process is critical for price discovery and liquidity. The proposal of eliminating this or changing it to an allocation process with a reallocation allowed on a secondary basis would really eliminate one of the primary vehicles for liquidity in our markets today. And I'll illustrate that in PJM.

The problem with the congestion offset metric, as described by PJM, is that the metric sort of implicitly assumes or implies that customers should be paying spot prices. Right? Because it's a comparison of, what is the end result price, and did I do well against the spot price? Well, that's not really the right question. For customers, there's no spot or spot settled retail. Load serving entities (LSEs) are always hedged, and typically there's a premium to being in the market for hedge contracts. The congestion offset represents a misleading perspective, really, in the context of how it's created. Only the FTR hedges are considered, even though there are obviously a full spectrum of hedges available. Competitive buyers of FTRs, as Speaker 3 has illustrated, who are the major owners of FTRs in the auctions today, are on the sell side of the hedging markets that are outside of this. And, as a result, any potential benefits that seem or appear to come out of the FTR hedges are often translated into the actual hedges that customers are using external to the FTR market. So this can be a distortion there that can be misleading, especially in high congestion environments.

The offset congestion metric suffers from other issues. Obviously, it just looks at voluntary ARR conversions, and there are clearly differences between expectations and reality, especially if you look out a year in advance or more. And, finally, I can argue that customers are better off with the FTR auction than without.

I think you can boil this down conceptually to the following: if you're trying to hedge customers and trying to serve them, and someone's going to collect a risk premium associated with the risks inherent with making decisions on how to serve them, do you want those risk premiums to be transparent, and then the subject of intense competition, meaning anyone can participate? Anyone could enter in and collect an FTR, use it as a hedge for a potential competitive activity? Or, the flip side of this, do you want risk premiums to be obscured in a market that is restricted, or where there are few, I would call them privileged, participants? That's going to be an environment with a high risk premium, and potentially higher rents collected, using the concept of rent that was introduced, I think potentially misleadingly, in the FTR congestion element.

For these reasons, I will say the FTR auction is in the best interest of the wholesale market. Let's kind of go over some of the data that underlies the core arguments here. The FTR has a financial payout that is equal to its equivalent physifal right, but FTRs do allow redispatch. If someone holds a physical right to transmission, it could block any other use that even has a small requirement in that physical transmission, and would sort of prevent redispatch, or prevent competitive supply, which is really not in the interest of customers.

Looking at active participation in PJM, if you want to look over the last ten years, these are the number of participants in FTRs. These are distinct, competitive, or corporate entities who've owned an FTR in PJM, and you can see that in some years, it's close to 300 different entities. This represents a fairly large amount of competition. In fact, the last three years look like they're falling off. But those are actually years that haven't even come. These are forward positions up to three years out, and you can see that for the following year, even before the large annual auction prior to 2017/18, there are over 100 participants that hold positions today in the FTR auction, or in the FTR environment. That underlies a lot of competitive force. Right? And that's critical to the market.

Also, I want to illustrate the volumes over time. This chart is a bit more than a ten-year outlook. But I want to call your attention to the two lines on this graph (showing buys and sells, and buys only), and how they're spiky. Every year there's a significant capacity release in an annual auction. And so you get a lot of capacity sold. But there are two lines. There's the blue line, and there's the red line. The red line is the sum of buys and sells. It adds in the sales that occur. And you can see that, over time, especially in the last two or three years, the sales component has been very significant. That's really important, because that underlies a price discovery system. It's not just buyers, people just buying something. But it's people buying and selling, which means that a good price is established, a kind of benchmark price that's real. And the other thing to point out is that, outside of the annual auction (kind of the large spikes), the underlying liquidity in the market has grown. You can see that month by month. You see the baseline seems to go up. And that means there's a lot of liquidity in the market today in PJM, which is important.

Who owns these things? This slide is just a repeat of some of the data that Speaker 3 put forward. But, clearly, a key to the liquidity on both the offer and sales side is really the financial participation of entities that are in there to help facilitate third party competition. And they're a vast majority of both the bids as well as the awards. So you get a sense of an FTR auction that's vibrant, that has competitive forces, buying and selling these FTRs. They're essentially helping people use the transmission system for competitive supply.

The next slide illustrates this issue of, OK, are the auctions just not generating an adequate amount of revenue, given the expected congestion on the back end, or the expected potential payouts associated with these contracts? And this is a ten-year historical view for just PJM, comparing auction revenue and congestion credits. And you can see the blue line, which is the auction revenue, and the green line, which is the amount of credits paid out under those contracts after the congestion has occurred. And you can see that they bounce around, but they do tend to track each other. Sometimes there are years in which the expectation of congestion ended up being much higher than actual congestion. And then there are years, and I'll just illustrate two of them here…in 2013/14, you can see that the expectation of congestion was significantly lower than actual congestion. And then you'll see also the following year, there was the same thing that happened, but for a slightly different reason. If you just take that one outlier, the 13/14, and sum the totals over these ten or eleven years, it's ten years, you get, essentially, a parity. So this concept of leakage, I don't think exists, just from a high-level perspective. So that's critical.

The other thing that I wanted to point out is that ARRs are allocated up to essentially all available capacity in the auctions. And they're allocated to load serving entities of record as of the auction. And these load serving entities have the right to hold onto those ARRs, or to liquidate them in the FTR auction. And as, over the last eight-year horizon, LSEs have, by and large, opted, 2/3 of the time, to liquidate these hedges. Now, it's not that they're just taking a bet that, "Oh, congestion's going down. I'll just the money, thank you." It's really that they're saying the auction is providing adequate revenue for the hedge that I was allocated, but I want a different hedge, or I want to restructure that hedge outside of the market. And it really illustrates the fact that, one, auction revenues are strong, right? These allocations are opting to sell them. And, number two, that there's liquidity outside of the FTR auction for these hedges.

Now, these go hand in hand. And I'll describe a little bit why that is. The FTR auction is a critical resource for those providing bilateral hedge contracts. You wouldn't have a very liquid market outside of the FTR auctions without those FTR contracts being made available publicly. That's a really critical element. And this slide sort of illustrates that with a diagram. You can see how the ARR allocation occurs ahead of time, and then flows into the FTR auction. Customers, the load serving entities, can elect to have just ARR revenue. They can just liquidate the ARRs. Or they can self-schedule and get FTRs. Or they can purchase FTRs in the auction itself. And sometimes people will liquidate their ARRs to purchase something slightly different in the auction. But also, if you go in the right-hand side, there's the exchange broker or bilateral markets. You can also purchase contracts for hedging in those markets. And there are some reasons for that. First of all, you can structure these contracts as futures. There are options, potentially, that might be more attractive from a hedging perspective based on the type of volatility you're trying to hedge. You can structure different types of contracts that are not available in the FTR auctions. They may want to, essentially, have what looks like an FTR, but structured slightly differently, and you procure them from a third-party perspective. What's really critical, though, is that the structure is absolutely essential to have open access or open usage of the FTR market for the competitive suppliers. These are potential generators that are trying to supply on a competitive basis. Or they're load serving entities that are trying to gain share. Right? And they aren't necessarily, maybe, the load of record, but they want to become that as they compete for customers. Those entities may not have the rights to ARRs, may not technically have the right, under potentially a revisionist view of how the grids should be used, to use the grid. But under this open access structure, where they can purchase FTRs, they then can hedge potential activity that would be commercially important for competition. And then there are financial participants, banks or other suppliers, which are buying a lot of FTRs.

But the basic function for the largest buyers of FTRs is to hedge internally the sales that are going on in these third-party markets. And you would not be able to sell effectively the same types of hedges without having FTRs as part of a process for hedging. Essentially, they become hedges to a financial book of these other contracts, or a physical book of bilateral contracts. And those are absolutely critical.

The FTR market promotes and facilitates the trading in the broader electricity market. They're absolutely critical to third party competition. I want to illustrate that with this slide here. This is a graph of congestion hedge trading in PJM's market, showing the monthly auctions that occur month by month in PJM, alongside the sum of what is publicly available on the exchange or broker related markets. And you can see that, over time, that publicly available share has started to increase. But it's increased hand in hand with the FTR liquidity. That's really important. So you can see the growth rate has been roughly around 13 to 14%. The underlying FTR has grown about 12%, outside of the annual auction. The bilateral market's grown about 14%. So it's a little bit faster growing, but highly related.

So those are sort of the data around competition, and I wanted to just outline a couple of closing comments on the offset metric. A lot has been made of this offset metric, where there are a couple of years of low offset, according to the way it's defined. And these come from two years, the 2013/14 year, where you had a large congestion event related to the Polar Vortex in 2014 (January, February and March), as well as an event which was surprising to everybody, where you went from a highly underfunded situation and expectation to a fully funded situation, which resulted, also, in apparent sort of lower auction prices versus the actual settlement. And if I just go into this, the Polar Vortex, this is the revenue of FTRs versus the auction price, the auction revenue versus the payouts on the FTRs, and it's just three months that represent all the deviation--January, February and March. And if you look at those three months, you had the weathercooling degree days and heating degree days on the top graph, and on the bottom, you have natural gas contracts. And in January, both of these were above expected ranges by a large margin, especially on the gas side. You can see the price ranges for market trading, but the blue dot is where the actual settlement occurred. And you can see, it's like orders of magnitude above it. Just completely out of the range. And so there's no way that an FTR would have been priced adequately enough a year ahead, or seven months ahead, to deal with that particular payout scenario, or that particular high cost environment. February and March had the same sort of generic way above expectation perspective.

And, before I leave this, in this context, you'd say, "Wow, people who bought FTRs would have been, you know, very fortunate to hold them during January, February or March." And, certainly, those who held on to FTRs to serve load would have been well-served by those types of FTRs. But, by and large, the holders of FTRs who weren't serving load directly were holding contracts with folks that were serving load on the bilateral side. So where you might have had FTR payouts that looked like they were very rich and highly beneficial to the holder of that, from a financial perspective, they were actually hedging an internal book serving load through exchange, like a futures contract, or bilateral or physical contracts on the other side. And, by and large, there were mostly basically even portfolios. So it may appear to someone like Speaker 3, who was just looking at the FTR side, that, gee, this was a bad event for folks that could have just held onto their FTRs and not sold them. But, in fact, they likely replaced them through hedges. Everyone's hedged in these markets. And those hedges paid out and covered these events.

A quick illustration. Speaker 3 already showed this slide, on the underfunding of FTRs. If you stopped that slide right at the beginning of the 14/15 auction, the perspective was of a high degree of underfunding, and it just so happened that the future changed, and that likely represented a large part of the deviation that is shown in the graph that was illustrating on the metric.

I will quickly summarize. FTR auctions are competitive. They've experienced increasing liquidity over the past ten years. FTR auctions are really critical to enabling competition in power markets by providing price discovery and liquidity and so forth, and as a result, the current structure is in the best interest of wholesale markets and benefits end consumers. Thank you.

Question: You had one slide up there that confused me a little bit. Maybe you can explain. It was that on the physical side you cannot impact dispatch, but on the financial FTR side you can impact dispatch. I didn't understand your point, or actually if you are saying an FTR impacts dispatch.

Speaker 4: No, no, no. The issue is, if you had a load serving entity with a physical transmission right, defined from their generator to their load, having that physical right means they have the right to self-schedule their generator. And, actually, no one can displace them unless there's a TLR (transmission loading relief event). Right? If there were a cheaper generation source available, there would be no redispatch capability unless there was relinquishing of those physical rights associated with that--if the new generator used, at least partially, those new rights, or those old physical rights. Does that make sense? So the physical right market is one which is sort of rigid from a contractual perspective.

Question: So, if you went with, say, some of the recommendations to change the current allocation of historical generation, and somehow make it more fluid or modern, if you will, does your statement still hold up?

Speaker 4: Well, you know, I think anything that deals with ARRs and FTRs is aside from this issue. I think any allocation of ARRs that seems to be effective at providing for current load serving entities, a set of paths that make sense for them today and gives them some options of reconfiguring these, makes sense. You know, there's no problem with that.

General Discussion [start here]

Question 1: It seemed like the crux of the issue from the panel this morning is, where is the money going? And so my question is, if financial players are making a lot of profits from the FTR markets, why aren't consumers getting that money? And if traders are making money, it seems logical that consumers must be paying more, and the money has to come from somewhere. And that seems to be basically the crux of what Speaker 2 and Speaker 3 are saying.

First respondent: OK, I think this is a great kind of question to resolve some of the issue. And the question, I think, should be rephrased, perhaps, as why the customers are actually getting the value, because, in a sense, as part of our process of buying and selling hedges and FTRs, we are competing to serve the customer. Right? In the context of the fact that the only positions we get are the ones where we've offered to pay the most, right, or we're the ones offering to sell at the lowest price. So, at the end of the day, the wholesale market has benefited by folks going out there and competing. And if making a profit is a problem, well, then, I think we have fundamental problems, because there would be no motivation for competition if you took all profits away from everybody and said, “There’s no profit incentive left.” You’d have, essentially, a wholly regulated market. You’d have a sort of monopoly that’s managed, and they have a profit, by the way, that often would far exceed the competition in the market. So the presumption here is that these profits are just taken away from the customer, but, in fact, they’re part of the link of serving the customer. So that’s the answer.

Respondent 2: I think it’s stronger than that. Suppose that you have an intermediary who comes and purchases an FTR in the auction, and then turns around and signs a bilateral contract with a load to hedge the load. What shows up in the data here is that they bought the FTR for whatever they paid for it, and then, when you calculate the actual congestion costs in the real time, and compare the actual congestion payments under the FTR to what they paid for the FTR, the presumption is, between the lines, that the financial trader is capturing this entire difference. But if they’ve actually sold a forward contract for the load, to hedge the load, the difference actually goes to the load.

And so, this, I thought, was the whole point about looking at just the difference in the congestion revenues. If you’re worried about what the loads are actually paying, ultimately, congestion revenues are only a part of the story. I don’t know what’s actually happening. I’m just saying that, from an analytical point of view, it’s clear you’re not asking the right questions by looking at just those particular numbers, if what your concern is is how much the loads are ultimately paying. So maybe it could turn out the data would come out the other way, and the financial traders are actually buying the FTRs and holding them, and they’re not hedging forward with loads, and then they’re not benefiting. But if they are 100% doing it, then it’s completely the opposite conclusion. So the answer is, you just can’t look at that number and know the answer to the question that is being posed about this.

Respondent 3: Can I respond to Respondent 1’s comments on where the profits are going? If, as he implied, no one’s making any money, then where are the markets? I mean, what we’re seeing is that it’s kind of the reverse. Instead of a risk premium, someone who is paying a risk premium in order to hedge the risk of an uncertain floating payout, the profit’s on the other side. Right? Rate payers are selling the fixed side and taking on risk, and losing money in doing so. Right? So what we’re proposing is that, instead of having the rate payers sell this fixed for floating contract at a loss, if someone wants a hedge on their risk, right, then they could place a bid, saying how much they would be willing to pay for that fixed for floating swap, and so then a financial entity on the other side could then take on that risk and make money, because they would be getting paid a higher fixed price than their obligation to pay out. I mean, that’s the risk premium. The risk premium should be paid by the company who’s paying to have a hedge. On average, they should be losing a little bit of money in order to protect against the risk of these uncertain point to point payouts. In fact, what we’re seeing is the opposite.

Respondent 4: Can I just add something here? First of all, we don’t know the extent to which FTR holders are speculating versus hedging. My view of it is, it’s probably mostly speculation. Speculation’s not a dirty word, but it also means that it’s not necessarily hedging that’s going on. So all the logic that Respondent 1 was talking about may or may not be true. But Respondent 1’s process is a pretty circuitous path to get to the right answer. Why should load allow some of the congestion revenue to go to the financial entities, so the financial entity can turn around to design a hedge for them? Why not just do it right in the first place, assign all the congestion revenues to load, then if load wants to enter into an arm's length deal at whatever price they agreed to, to trade that for a fixed payment, then that's fine. And then the financial buyer can structure it however they want. But to have to not get the right amount of money in the first place, to give some of the excess to financial buyers in the hope that some of them will provide a nice hedge, seems like a very illogical, inefficient, circuitous way to do it.

Respondent 1: Can I just jump in one second? I think part of the challenge is, if we lose our focus on the objective, then I think we can get mired into the details of entitlements or efficiency and so forth. The objective really is to establish a liquid wholesale market. Open access, 888, the point is is to establish the opening of competition using transmission. And in the context of that, you want to have prices. You want to price what the value of transmission is. You want to be able to have liquidity. You want to have transparency. That's the objective. And I don't see how you have a good, competitive wholesale market without competition on price, with anyone being able to buy and sell, and that's the whole point. If we're now saying, "Oh, let's forget the market, and let's just think, from a black box perspective, about how, knowing the solution from the end backwards, we can derive some new kind of construct that would be potentially cheaper and get rid of profit motives," I think that's sort of the problem we end up debating, entitlement and cash flows and so forth, if we lose that objective.

Respondent 4: Hold on one sec. So, I agree we ought to focus on the basics. I'm not sure that what you just said really exemplifies that. We're not anticompetitive. We're not antimarket. Quite the reverse. We're in favor of liquid wholesale power markets that are transparent and open access. But what this is about in particular is, to whom does the hedge belong? To whom do congestion revenues belong? And that's really all it's about. And then, what's the best way to structure that, entirely consistent with competitive wholesale power markets? So I don't agree with your characterization. Our proposal is certainly not anticompetitive. It's not anti-open access, and it's not anticompetition. Quite the reverse.

Respondent 3: If there isn't a liquid bilateral market in California, I would argue that that's likely because rate payers are selling off these fixed for floating financial swaps at a zero-dollar reservation price. If you're going to buy a swap, I think you're going to want to transact with someone who is offering it at zero dollars before you go buy it from someone who's actually offering it where there's a risk premium built in. So I think our proposal is to create a market, right? To stop forcing rate payers to sell financial swaps for a loss at a zero-dollar reservation price, and instead, you can still run the auction. Right? You just set the limits, when you run this optimization, set the limits in an optimization equal to the flows on each constraint that comes out of the allocation process. So that if someone's going to then buy a hedge, it has to be from a willing counterparty who has offered to sell the hedge at a price at which both people agree and which both people find to be beneficial. That's it.

Questioner: So if I could try to put together what Respondent 1 and Respondent 2 said, at the end of the day, if there are people using these as hedges for congestion, and they're also serving load, presumably there's some risk premium that they are asking for when they are competing to serve that load, and so part of the issue I think Respondent 2 is bringing up about how these spot markets for congestion are connected with traded markets between generators and loads, is that that risk premium, if these markets are competitive, goes down and down and down. And the way these markets used to work is, you'd have originators or banks that would go to a generator, and they'd do deals with the generator. They'd go to load in the same area, and do deals with the load. This is maybe ten or 15 years ago, with really high risk premiums there. So load is paying a much bigger risk premium than with a liquid transparent market facilitated by Financial Transmission Rights. And we see those risk premiums going down over time.

Question 2: I just wanted to ask Speaker 3 what the definition of that profit term was, and whether there was any data or metric to indicate whether the return on capital employed or some notion of profitability was changing in a way that might lead you to think that there is a problem with the market design?

Respondent 1: So the metric is very simple. It is the revenue minus the cost. And, no, we don't know what the capital deployed is by individual participants in the FTR auction, so we're not doing a rate of return. We're simply looking at the aggregate amount of profits. I mean, in fairness to what Speaker 2 and others said, I mean, we don't have access to the books and records of the companies. We don't know what all the financial positions are. It could be an exactly accurate measure for a speculator. It might not be, if they're turning around and doing something else with the FTR. But neither of those things really matter to our point.

Question 3: I was wondering how much, potentially, credit requirements in those markets might also play a role in the divergence between the pricing that we're seeing between those products?

Respondent 1: I think it clearly plays a role. There are very significant credit requirements in the FTR market.

Respondent 2: I guess that may lead into a broader question about potential lack of competition. Right? Why is there not sufficient competition? Credit requirements being one of the reasons. Like, what are the barriers to entry for people who can participate in the FTR auction and potentially drive up those auction revenues to equal the expected payout on the contracts? I think one key barrier to entry is the complexity. Right? And I guess we can get to the more economic side of it. But there is massive uncertainty about what the model is going to be in each of the 720 hour utilizations of the day in market models. And there's one FTR model for each monthly auction. So there's huge uncertainty there. A lot of complexity. And so the fact, then, that in this auction you're effectively selling a separate product than ends up being settled on in the day ahead market, creates opportunity for people to really study those potential model differences and come in and profit from those differences. And so I guess the differences in the models kind of creates complexity, which creates a barrier to competition.

Question 4: It seems to me that Speaker 3 is making, not an economic efficiency argument, but a fairness argument. And it's based on, fundamentally, the idea that load is paying for the transmission system, and they ought to get something for it. And I'm wondering if maybe that's the heart of the problem--that everyone that's going to make money off the transmission system ought to be paying for it, and maybe fundamentally we need to rethink whether just load ought to be paying for the transmission system.

Respondent 1: Let's have a beneficiary pays transmission. I don't know, that was too hard. [LAUGHTER]

Questioner: Yeah, that was loaded.

Respondent 2: I think our recommendation is consistent with both efficiency and equity. I'm certainly not recommending that we change the way the transmission system's paid for, with the possible exception of some of the other filings we made about how competition and transmission should work, which is a whole other panel. But, I mean, there's a simple way to do this. I think that's what we suggested. And you don't need to go to how transmission's paid for. You simply need to go to, why is there excess revenue? What's the design? How can it work effectively with a nodal network model? And we think our answer is simple, straightforward, and answers the question.

Moderator: Just so I understand a little better, because I think I am somewhat confused. Is the reason load isn't getting the money, in your view, just because the spot market is different from what the auction prices were at the beginning of the year? Or is there something else going on there?

Respondent 2: No, that's not what it is. I mean, there are leakages for a number of reasons. But a primary reasons is using gen to load paths to assign ARRs. I mean, that's probably the most significant reason. But that, then, relates to what the alternative would be. The alternative would be simply to assign the congestion revenues to load and then let them sell that if they wish to. So the point is that the paths can never adequately capture the actual network congestion. They simply can't do it.

Question 5: I've got a lot of questions. Oh, boy, do I have a lot of questions. So I guess the first thing I want to start with is really for Speaker 2 and Speaker 3. Do you agree with the premise that Speaker 1 has put forth, which is that FTRs are a necessary condition to translate physical transmission rights to a financial system, where we have LMP, and that without that, things start falling apart, and it's the only market design that works? Do you agree with that, or not? And if you do agree with that, then what is your proposal to allocate FTRs or ARRs to load, or to transmission customers, because it could be somebody other than the loads? How would you allocate that to preserve that fundamental foundation without blowing up the whole system? Because I can imagine, for example, if all load just purchased from the spot market, then the allocation mechanism doesn't become an allocation mechanism about use of the transmission system; rather, it's an allocation mechanism for a pot of money. And rather than this being a competition between load and financial players and generators, you're now going to put loads against each other to get a bigger pot of that money. And that doesn't do anything to preserve the integrity of the system. I mean, I'm asserting that Speaker 1 is absolutely correct about it. And so one could imagine that. So how would you do that? Why don't source and sink points work? I asked the clarifying question of you, Speaker 3. Why don't having more up to date source and sink points work to allocate ARRs? What's the problem with that? Especially given the data in the *State of the Market* report that clearly shows that most of the energy in PJM is either done through self-supply or by lateral contracts. What's the flaw in allocating the ARRs that way? I'll just stop there.

Respondent 1: I guess I wasn't clear the first time through. So let me try again. Of course, what we're proposing is entirely consistent with the design as Speaker 1 described it. Just think about how FTRs worked in 1999. They work exactly as we've described, with the exception that there were some allocation issues based on the fact that gen to load paths were used instead of simply assigning all congestion revenues to load. So all those allocations issues you talk about, about pitting load against one another, exist right now. And clearly there are some tensions and there are some allocation issues. So we resolve both the broader issue as well as that narrow issue by proposing to assign congestion revenues to load. And the reason that a gen to load path doesn't get it, is because that's not the way power flows in our network, as you know very well. So I'm not really quite sure why you keep asking that question. It cannot capture the congestion revenues, and it doesn't. So congestion revenues exist as they exist in a network system. That's the purpose of having the FTR, to return those congestion revenues to the load that pays for the transmission system that made them possible. And it's no more complicated than that. It's entirely consistent with the design. It's not going to blow it up. It's entirely consistent with it. In fact, it's the way it worked in 2003, exactly the way it worked.

Questioner: Just a point of clarification, I never mentioned transmission path. I explicitly said source and sink points.

Respondent 1: OK, but that's what that means.

Questioner: No, it doesn't.

Respondent 1: Yes, it absolutely does. Why doesn't it mean that?

Questioner: Because power flows over the path of least impedance. All you're talking about is the source and sink. It doesn't mean that power's going over the contract path from the source to the sink.

Respondent 1: You're assuming that the power's beginning at a particular place and ending up at another particular place, which is not true, and you don't know what that is ahead of time. And power's flowing where it flows. It's flowing based on the generation that's dispatched, the impedance in the system, the outages in the system, the actual nature of the system. You can't say that power is flowing from your generator to your load.

Moderator: So, Respondent 1, if you allocated the congestion rents directly to load, and they're in the BGS (basic generation service) auction for standard offer service, it seems that the load would probably include their ARR rights, whatever rights they had, in the offer to the people who are buying that obligation to serve load, and that the buyer of the FTRs should be those who value them the most. I'm not clear if the problem here is in how we're allocating the ARRs or FTRs or the rights to the load, or it's just the fact that we're allowing for an open market for people to buy them.

Respondent 1: I'm not totally sure I understand your question. But ARRs would be assigned to you and me as individual customers. They'd be assigned to load serving entities, and if a load serving entity wins an auction, the BGS or any other, or wins the right to or serves retail load for some reason, they would also have rights to congestion revenues. And that simply flows from serving load. And, as I said earlier, if that load serving entity then prefers to have a fixed payment, and not bear the risk of what actual congestion will turn out to be, they can then run an auction, and they can sell that to someone who wants to trade with them.

Moderator: OK, but the actual utilities, the load serving entities, if they were given these rights, they might actually ask PJM to organize an auction for them to sell them off.

Respondent 1: Fine.

Question 6: I hate to inject reality into a great discussion. But as a load serving entity, I can tell you that we fall somewhere in between Speaker 3 and Speaker 4. And that is, we think the FTR/ARR construct does benefit consumers. In the load auctions, when we are taking the responsibility, the FTR/ARR structure allows us to be competitive. Some of us are arrogant, and we think we do a better job than others of picking and choosing. So there are benefits.

But I would like to go to the broader description of this panel, which looks at some other issues. Because it's really not whether, in our view, the ARR/FTR structure is good. We think it's a good structure. It's a couple of other things. One, it's a modeling issue. PJM still can't model things correctly. And that creates problems. Two, it's the actual funding of the congestion rents that are arguably what we are fighting about at FERC, and I suspect that Speaker 4 and I would part views on this. And I am happy to go into this at some point if we want to take the discussion down that road.

The other thing is the political pressures that PJM faces when they're underfunded or overfunded the next year. Suddenly we get more or fewer FTRs or ARRs, purely coincidentally. And that goes, again, to the modeling issue.

And, finally, I'd ask whether we have seen, with the ten year FTRs, that that undermined the ability to release more short term ARRs.

One other issue is market manipulation. We haven't talked about UTCs and virtuals and DECs--not to say they're wrong. They're in the rules. But they clearly are undermining, to some degree that we can't quantify. All we can see is a correlation. So I am going to the broader question posed here, because I think there's a lot of meat there, and looking for some responses.

Moderator: That's a great question. And I'll turn it over to you guys. But to just add on to it, is there something magical about the quantity of FTRs that are auctioned off or that are allocated to ARR holders? And I will open that up. I have an answer. But --

Respondent 1: Let me address that. I don't have any issue with the allocation process. For me, that's a separate argument. What my issue is, is what happens after the allocation process? Should more of these financial swaps then be sold off by rate payers at a zero-dollar reservation price? So to answer the Moderator's question, there is nothing magical about that limit.

To go back to the example we talked about, if there's 100 megawatt line, and 80 megawatts ends up allocated, then there's 20 megawatts left. Right? The reason to a set the limit in the auction at 80 megawatts would be to make sure there's a shadow price. Right? If you didn't set a limit, there wouldn't be any shadow price, and the rate payers would be auctioning off an unlimited amount of these financial swaps at a zero-dollar reservation price. So if, instead, you set the limit in the auction at those 80 megawatts, at the amount cleared out of the allocation process, then you can still have financial swaps sold at any quantity. It could be 20 megawatts sold. There could be 30 megawatts sold. Actually, even if you set the limit at 100 megawatts in the auction, and, say, only 20 megawatts get sold in the auction, that doesn't represent some actual physical right. In the bilateral market, people who didn't get that extra 20 megawatts can go out and procure more financial swaps--more than 20 megawatts. Right? This idea of these things in the auction is that they're just financial swaps. They're not linked to the physical.

Moderator: So I guess what I would say is, what is magical about the quantity that's sold is that it is tied to the actual physical transfer capability on the system. And the idea is, you're auctioning off FTRs that are equal to the physical transfer capability. They don't exactly match the sources and sinks. And there's something really valuable in not auctioning off more or less, but auctioning off the right amount. And that's the integrity of the financial instrument. And it's highly valuable, if you auction off 100 megawatts, that actually what the person who receives it gets is exactly 100 megawatts, and that's useful for hedging and for forward contracting, and that's how virtually every other forward financial product would work. And so, from a public policy perspective, I would argue that's really important in terms of facilitating these other markets for transactions.

Respondent 1: That's where we fundamentally disagree. When you go into that auction, the only thing magical about the limit you set in the FTR auction is that you have to set it at something, so you get a shadow price, so that there's actually a price on the auction. If you didn't auction off any additional capacity, people can still go and get their fixed for floating financial swaps from other people, not from rate payers.

Moderator: And in a quantity which may have little to do with the amount of transmission that wasn't allocated in the FTR allocation process. But you'd agree that if the constraint was 100 megawatts of flow, the ISO wouldn't necessarily want to be auctioning off 200 megawatts of congestion. You set limits based on the physical flow.

Respondent 1: The ISO shouldn't be auctioning off any, because what matters to the rate payer is, will the revenues I receive from these financial swaps that the ISO auctions off on my behalf be greater than my obligation to pay off on the floating side of the contract? The ISO shouldn't be in the business of figuring out how much rate payers should be auctioning off. That should be a private decision that should be made in the marketplace, not by a nonprofit rating agency.

Moderator: To the questioner, I hope I haven't hijacked your question. [LAUGHTER] Anybody else want to respond?

Respondent 2: To the questioner, I think we're actually quite well aligned. So let's agree that we agree. One of the things I want to point out is some of the perspective I come with. We often are approached to provide what are termed "bus bar hedges." So a typical example might be a solar facility that is being developed by a project developer. Typically, they have a bank who's willing to loan them money. But the bank is not too comfortable with the bus bar, the LMP hedge down to the location. And part of the challenge we face is that the horizon on FTRs is only about three years in PJM (and a lot of the activity that is liquid in the market today is PJM). So our traders really aren't allowed to go beyond three years, because a bus bar hedge is actually quite a kind of challenging thing to hedge internally. So in the context of providing that hedge to the market, we can say, "Well, we can price it out, but it will be up to three years." Essentially, the horizon of PJM's long term auction. Beyond that, there really isn't anything. There's just nothing. And the banks aren't very comfortable with it.

I mean, we are a specialist in congestion for the US market. We're not comfortable with it. To the extent that auctions would be enabled for the time period beyond three years, not just kind of long term FTR-type entitlements that go ten years, but actual auctions, that would actually open things up. And the developers really rely on seven to ten year horizons to justify a lot of these projects. And that gap, beyond three years, really is sort of a problem. You know? And liquidity does come from the primary FTRs auctioned off by the ISO into the bilateral market, and hedges are achievable under that umbrella. We know this. We see this all the time. The implicit premiums that are paid by people willing to hedge are based on the competition of all the other people willing to provide the hedges. And it's reasonably competitive in the horizon of the auction. And that's a critical thing.

Questioner: Could I just do a follow up? Because you do raise an interesting point, which is, you're hedging for a generator. You want them to model something ten years out. That goes to the RTO's points, to Speaker 2 and Speaker 3's points, that when you do model the ten year, you are taking away those products for load. So what you're arguing for, I think, would reinforce their view that when you look for a longer hedge, you're doing it for the generator who has paid its interconnection rights, but not its congestion rights, and in looking for a longer hedge, you are taking away potential FTR/ARR allocations to load. And I'm wondering if you would agree with that.

Respondent 2: Well, the load angle is a good one, but, clearly, for example, public auctions of capacity are about the two to three-year timeframe. And so they fit nicely within the current horizon for liquidity. When we have competitive retail, so, for example, retailers that are serving competitive load in Maryland, and when we interact with them, a two to three-year horizon works perfectly for them. The competitive side is not really looking for a ten-year deal, because their customer transaction, the retail deal they have at the retail side, is only a year to maybe two or three years. So, in that context, they're looking for hedges of that time period.

I think the other question that you're addressing is more philosophical. The key is, from our perspective, the competitive load or the regulated load that's offered for public auction under the state mandated auction processes, those are out there getting hedged through transactions that we support within our company.

Respondent 1: I would just add that nothing in that long description about how the market works is inconsistent with what we are saying about how revenue should be assigned to ARRs, nothing whatsoever. And the load recipients of congestion revenues could very well, as I've said repeatedly, turn around and sell that to FTR buyers, if they wanted to, but consistent with what Speaker 2 has been saying, it might not be at quite as low a price as they're being bought now. But, nonetheless, it would be a price, and then all those things could happen. There's no requirement that load fund the hedging capability of financial participants. I mean, if there were no congestion revenues for others, then the financial players just have to figure out other ways to hedge. I mean, it's interesting that they can't do it on their own bilateral markets. It relies entirely on congestion revenue from the PJM market.

Question 7: Well, Respondent 2 for the last question just raised the point I was really going to raise, so I'll just make sure we're clear if we're seeing it the same way, and we can move on.

As I see climate issues leading to more remote generation, and that's certainly the case in the wind industry, and transmission infrastructure's not getting easier, it's getting harder, and you're trying to finance generation… So, if you're looking at sort of national economic energy policy, you've got to be thinking about, "Well, how are we going to get a lot more zero carbon energy on the grid?" And part of that is lower financing costs. Given the increasing basis risk that all of our generators and investors are seeing, and all of the Facebooks and Googles that are now trying to buy clean energy, and suddenly realizing, "Oh crap, we've got a huge basis risk problem, and what are we going to do here?" we need long term rights. So I think we need to sort of add that back into the equation here. I know it makes it even more intractable. It's discouraging to see that we don't even agree on the purpose of a lot of this, when we have what I think is kind of a whole new challenge overlaying all of this, that we all need to put a lot of smart minds on. Am I off base? It's probably a question for another day. But do you see that issue?

Respondent 1: My first answer to all questions related to carbon is, we need a carbon price. I assume you agree. I just wanted to say it anyway, sorry.

So generators face basis risk, of course. The question is, whose risk is that? Who should bear it? Is there some social policy reason for load to give its congestion rights to the wind generators, so they don't face that basis risk, or should a wind generator enter into a long-term contract with a load who already has ARRs? I mean, all that can happen. I certainly don't think it's an appropriate way to think about modifying the ARR/FTR construct to suddenly provide those revenues to wind, because they're facing basis risk, and they're socially beneficial because they have low carbon footprints. So I get your point, but I don't see why it changes what we're talking about here.

Question 8: I really liked Speaker 2's example of the 100 megawatts, because that's something I can actually understand. So as I sort of hear you both saying, and I think Speaker 2 and Speaker 3 are actually saying the same thing, which is that, in that example, there's 80 megawatts that's basically devoted to serving native load, back to ancient times. And then there's an extra 20% of head room on the system. And what I hear you both sort of focusing on is, how much of that 20% should be sold? How much of the revenues from selling that extra 20% should go back to load, versus going to other participants in the FTR market? And, when I think about it, you sort of think about going back, again, to that example of serving native load, 80% of the system was devoted to that. So it makes sense that the holder of that load should get their 80%. But then I don't necessarily see who has the claim to that extra 20%. And is my understanding correct? And do you have any thoughts on that?

Respondent 1: My starting point is that the entity that has the claim to the congestion rents on that extra 20 megawatts is whoever paid for the transmission, or whoever paid for that steel to go in the ground. It's their congestion. That's their congestion rents. So, then, how should it be distributed? Right? The FTR allocation process does distribute some of that 100 megawatts. After the allocation process, you have 20 megawatts left over. The congestion rents still fundamentally belong to the rate payer, whoever is paying for that transmission. So I think that this kind of gets to the heart of things--does an auctioned FTR, does it represent the right to a congestion rent? And the answer is, no. Right? When you get to this auction process, having the rate payers running this auction with a limit set at 100 megawatts on that line, it just simply results in rate payers auctioning off 20 megawatts worth of a fixed for floating financial swap at whatever price comes out of that optimization. There's no need for them to do that. Anyone could provide that swap. It doesn't have to be done by rate payers through an FTR auction.

Moderator: I would say that the answer on this one is very clear, and there's consensus. It belongs to load. I think Speaker 4 would agree with that. I would agree with that. And I would also argue that load is getting that extra 20 megawatts, because, at the end of the day, there may be some that are a little bit more funded, some are a little bit less funded, but at the end of the day, the question is, if you're allocating the rights to the transmission system through ARRs, then are those ARRs completely feasible or infeasible? Meaning, did you allocate more than your actual transmission system capability overall? Or less? And all of the ISOs do a great job, when they run these FTR auctions, of trying to match up their ARR amount that they allocate, which is how much the capability is.

Respondent 2: So, at the risk of blowing up your consensus, I think that whole notion of extra capacity and focusing on the capacity of the system is a little bit misleading. I mean, what we're really talking about here is congestion revenues. Congestion revenues only exist when the transmission system's not adequate to provide the cheapest energy to all the load at a point in time. So transmission constraints have to exist. There's no headroom on that line when congestion exists. So you're not selling off headroom. What you're doing is assigning congestion revenues that result from the fact that there are actual transmission constraints. And what I would ask everyone is whether they agree, in the first instance, that the goal of the process is to assign congestion revenues back to the load who pays for the transmission system and who pays the rents. I mean, if they don't, OK, good. But it's important, to get that and make that clear, because I mean, that's --

Respondent 3: It's not always clear.

Respondent 2: Maybe I didn't get it. But so it is important to clarify that.

Respondent 3: There's several ideas here which are being conflated and which are confusing a lot of this discussion. So let's take Speaker 2's suggestion, which is that we take 100 megawatts of FTRs, and I'm going to ignore loop flow and all the other complications. We're going to have 100 megawatts, and we're going to assign those FTRs to the load somehow, and we're not going to assign it to load serving entities. We're going to assign it to each individual load. OK? Somehow. So we solve that problem. I don't know how to do that, but let's suppose we solve that problem. And then they don't have market power. So they'll go around and sell them based on whatever the opportunities are, if they're paying attention, and they're not couch potatoes. Right? So they're not ignoring all this kind of stuff. So we wouldn't need a BGS auction either, for that reason. That would work fine if we did this with these ex ante FTRs, and people actually did not have market power, and were prepared to sell them for their reservation price, and all that kind of thing. That would be terrific.

That was not the world we were living in when we were describing these things and setting these things up. And we had an understanding of the necessity of FTRs come out of this process. They're a necessary part of the efficiency of the market. It's not just moving the congestion rents back. If that was all the problem was, it would have been simple. But that's not the objective. The objective is to create these locational hedges, so that individual contracts, individual arrangements, can compete with each other and do all the things that we were talking about before. That's the objective. And if there were no congestion rents that were actually collected, but we had LMP prices anyhow (I don't know how), we'd still have to solve that problem. It's just convenient that we have the congestion rents in order to fund that kind of activity. But the objective is to create these Financial Transmission Rights.

And they have to be created ex ante. They are not created ex post. They are not created ex post, after we observed what happened in the short-term spot market, and then we say, "Oh, you paid this much congestion rent, so you get this much congestion rent back," because that unravels the whole market and unravels the incentives with LMP and everything else that's in the system.

So if the idea is, "We want to have a better ex ante allocation of the FTRs to people who will in fact trade them through the market," that's a great idea, and I'm all in favor of it. If the idea is, "We're going to have ex post collection of the congestion rents and give them back to the load," that unravels the whole electricity market. These are not the same things. They are very different proposals, and that would be very damaging to the long run efficiency and operation of these markets.

And if the idea is that we're going to allocate the FTRs to somebody who doesn't have market power, and they're going to trade, that's a good idea. But it is not true that the load serving entities in California, like the utilities, don't have market power. They have lots of market power. And this is a real problem. And so one of the reasons we got ARRs in the first place was to have some mechanism that would force them into the marketplace so that they would actually be traded. And the ex ante expectation is the value in the long run accrues to primarily to the load, including the premium value. But it is not the case that ex post it should be the same as the actual realized congestion rents, because that undoes all the incentives that we want to have operating at the margins.

So if all we want to do is do what Speaker 2 says, and we're going to allocate the FTRs to the individual consumers in California, I'm all in favor of it, except I don't know how to do it. But if it's to take that away and then to say, "No, what we're going to do is, we're going to allocate the congestion rents ex post," that causes the whole market to unravel, and I won't solve anybody's problem that way.

Respondent 1: I'm not suggesting any kind of change to the allocation process. Right? Still, it seems absolutely reasonable. I just see potentially all kinds of benefits for distributing the congestion rents through the process of allocating FTRs.

Respondent 3: Ex ante.

Respondent 1: Ex ante, yes. Allocate the FTRs ex ante. And then --

Respondent 3: …to somebody who doesn't have market power.

Respondent 1: OK, sure. That's not a debate that I'm getting into. That's a separate debate, from my perspective. Allocate the FTRs ahead of time. I mean, it's an allocation, not an auction. Right? It's an allocation. It's an allocation process.

Respondent 3: So how do you do that? That's what …

Moderator: Respondent 1, you're saying, "Allocate them, but don't let them auction them off after the fact?"

Respondent 1: No. I think once these contracts are allocated out to the entities who have paid for the transmission, then that sets the amount of FTRs that are out there, and then people can go and trade those however they want.

My issue is forcing rate payers to sell.

Respondent 3: This is a serious conceptual problem. And we have to clear this up. You keep saying that anybody can come in and offer a forward contract and FTR. That is true. Anybody can come in and offer a hedge between two places. Only the ISO can offer a forward contract that respects the transmission constraints of the aggregate transmission capacity and do this in an efficient way that is also revenue adequate. They are the only ones that can do that. It is not true that Enron can do it separately. And Enron argued that that's all you had to do in the past, and it was a stupid argument when they made it. And it is still not true, because of the network interaction. But you have to recognize, this is an absolutely critical part of the problem. Only the ISO is able to do it. The only way they can do that is to do the auction that they're doing with the capacity that they assign for the auction. And that inherently involves things like taking three megawatts going this way and trading it for two megawatts going that way, because of the interactions in the grid, and that's going to cause a complete reconfiguration of all of the FTRs, and it has to be modeled as constrained by the capacity of the system. It is not a simple decentralized bilateral market. It is an integrated market, because of the character of the network, and the design is critically built on that principle, and when you forget those things, and you start saying, "Anybody can do it. We can just do it and allocate it, and they can freely sell it any way they want," in fact, they can't. They have to go back to do the reconfiguration through the ISO auction. That's the only way they actually get that done.

Question 9: I am going to stick in the ex ante world here for a moment. We know that, from the load's perspective, with the financial intermediaries, the overall aggregate cost to the load is going to be less, because of market discovery and increased transparency. But what I'm really interested in, Speaker 3, is with your idea, do you have an idea how much the increase would be in the aggregate to the load if we went through with this idea that you have?

Respondent 1: So I'm not sure what you mean by increase in aggregate. You mean the total dollars that would change hands?

Questioner: Yes. In other words, I think your point is, there would be less of a financial market share if there's more information. Less risk and all that. Would it be reduced to 80%? 20%? Just roughly. Ideally, zero.

Respondent 1: Yes.so If you look at the numbers comparing the payout of total congestion revenues to load, the proportion varies between 99 and 45. So, regardless of whether you don't like some of the years or not, they're all real observations. So, depending on how much congestion there is during a year, in a 99% year, it's maybe $10 million. In a 45% year, it might be $500 million. So it depends on the year. But the total pot of money at issue here is around a billion dollars, as I showed you in the first slide. So we're talking about maybe, on average, about 10% of that. What we're talking about is the difference in total revenues that would go to load under what our proposal is. And our proposal is entirely consistent with assigning rights ex ante and selling them off in a way consistent with the capability of the system.

So what was in one of the comments from Speaker 1 that was interesting to me a moment ago was that the reason we went from FTRs only, which is where what I'm describing was actually happening, to ARRs and FTRs, where I think the problems began, when you combine it with generational load paths, is that I think the assertion was that just because load had market power, it wasn't doing something, I'm not quite sure what. So I don't think that particular transition was necessary, and I think it's created a lot of the issues we have, and the system worked fine, consistent with the original design, up to that point.

Questioner: Just so I'm clear, you're talking about a $100 million idea for the load.

Respondent 1: Yes.

Question 10: Speaker 3, you talk about the allocation being consistent. So what exactly is the allocation mechanism? How does it work, your ex ante allocation mechanism?

Respondent 1: So, you're allocated a share of congestion revenues, which would be known after the fact, and so there's risk associated with it, and you can sell that if you want. PJM can set up an auction to sell that, if somebody wanted to buy the rights to that uncertain congestion revenue and pay a fixed price for it.

Questioner: OK, then my follow up question is, is it associated with anything to do with the transmission system? From your answer, it sounds like there's nothing to do with the transmission system whatsoever.

Respondent 1: I'm hard pressed to figure out how you get to that. The transmission system results in congestion or the absence of congestion. So of course it depends on the transmission system.

Questioner: OK, let me rephrase it, then. It has nothing to do with whoever has a percentage of the congestion revenues, where their location is on the system, or if they have a physical bilateral contract with a generator, where the location of that generator is. Is that correct?

Respondent 1: It has nothing to do with any underlying bilateral contract with a generator or anybody else. That's right. Nor should it.

Questioner: There are no defined source and sink points with that allocation mechanism?

Respondent 1: That's right. We're not going from a particular source or particular sink.

Questioner: OK, just wanted to make sure.

Respondent 2: If I heard it correctly, there's an ex ante allocation, and this sounds to me faintly like a proposal in New Zealand a long time ago which was ultimately abandoned. So let's be careful about this. If I'm understanding correctly this idea, I'm allocated a share in the ex post congestion rents. So my property right as a load is, I get 1.3% of the ex post congestion rents. And then, if I want to, I can turn around and sell that property right to somebody else, so there'll be some kind of an auction.

Now, what is the nature of the auction? Is the auction, who would like to buy a 1.3% share of the ex post congestion rents? Well, that's going to be completely unrelated to the hedging problem of the generators and the loads and the basis risk differential. They have nothing to do with each other. That's why this idea was abandoned in New Zealand.

Then, OK, well, maybe we won't do that. We'll allocate 1.3% to me and to everybody else in the room, and then we'll have an auction which is an FTR auction. OK. I'm fine with that. So let's do that. OK? But people don't like that, because, well, the 1.3% guy said, "I didn't want to sell my share. I don't want to sell it through an FTR auction. I want to hang onto my 1.3% share. So I don't get 1.3% of the revenues in the auction. I want to get 1.3% of the ex post rentals." This mechanism doesn't hang together. It just doesn't create the FTR hedges that you actually need, because the property right you're defining is not related to the problem that you're trying to solve. And it is not about just returning the congestion rents.

And now, if you're going to allocate the shares ex ante, and you're going to have an FTR auction for the capacity, and then everybody gets a share of the revenues in the auction, not the revenues ex post, that's fine. That will work. We can do that. That would be a good system, or you could do something else. But what you can't do is just wave your hands and say, "We're going to allocate 1.3% of the ex post congestion revenues, and everything's going to work out." It's not going to work out.

Respondent 1: Just one point. So it is the case that, in our proposal, the congestion revenues would be locational. Now, they're not from a particular generator to a particular location, of course, but they are locational. So they're related to the congestion being paid by load at a particular point. And I don't understand why that makes everything not work, but the key thing is, it's not purely just money, although that's what it boils down to. It is related to, and in fact a direct function of, determined by, the amount of congestion paid by load at a particular point on the system.

Respondent 2: Wait. The total congestion rent depends on where the swing bus is, for example. You can't be going just against the total congestion rent at that location. So if you're at the swing bus, it's zero, unless we define it over there, and then it's all congestion. I would really like to see this proposal written down with the equations that would show us how this actually works. Because I do not know how to do this, and I would love to have a way to do it that is better than the way that we have, which is always going to be imperfect—that is, the initial allocation story. But I think the essential requirement of any scheme that must exist if you want to have a competitive market, is that, in the end, the ISO is running an FTR auction ex ante. Now, as to who gets what money, let's have a conversation about that. But if you don't do that, then you don't meet the requirements of the only way to do it.

Respondent 1: So you think it was wrong prior to 2003?

Respondent 2: No, it was fine. They allocated it, and they got the money.

Respondent 1: Right. But there wasn't an auction at that point.

Respondent 2: Oh, no, I think that's a mistake. I think that's the problem.

Moderator: There were monthly auctions.

Question 11: So, Speaker 3, my fundamental concern with your proposal is, again, I think that we bring value in managing the risk, the actual product, and you take that away. You just give load whatever, and we actually think we're smart enough to pick better paths and provide value to our customers in doing it. So I have a little bit trouble with that.

And I'd like to go back to my earlier question, which is that it seems to me that there is risk in the system, and load should bear it. Some days, you know, the system is modeled correctly.

Everything works correctly. And when it doesn't, we think it's appropriate that load bears that risk. The FTRs are supposed to reflect that. Our concern is, again, do you see any manipulation of the flows that impact the FTR products? Because that concerns us. And that's within the scope of this discussion. I know, I read the description of it. And the other thing is, again, the funding. If you had, if you would, pure funding of the actual congestion costs, and that was allocated among all the FTR holders, would this be such an issue? Or is it the problem of capturing what are the legitimate costs that should go into the allocation of the funding?

Respondent 1: No, yes, and yes. I don't think that you or any other load serving entity is so smart you can get more revenues to load than they're paying in congestion. Maybe you are, and if you are, more power to you. So I don't get that argument.

The second argument is, is there a possibility to manipulate in the FTR auction? Of course there is. And we certainly see it from time to time. So there are lots of opportunities to manipulate any market, and there are certainly opportunities in the FTR market.

And the last question is, if there were a better way to assign revenues to load, could the current system still work? I think the answer is yes. If load were assigned all of the congestion revenues, and there were not this leakage, then, yes, it could work.

Respondent 2: Can I jump in? You know, I think you might have your own perspective on this, but it would be very helpful from a transparency perspective to have public data on the actual bids and offers for all the elements of the market, after a suitable amount of time. Because then you really could look at this issue that you are concerned about. For example, you know, today it's very difficult to know whether there were some operational issues that PJM chose to model a certain way that caused some of the effects that you might see in congestion management, or whether it was a UTC transaction, or whether there was some other interesting dispatch configuration of the physical system, you know, with the actual breakers and so forth in certain ways, that actually caused that. Or was it some generator bids, or the actual real time load segmentation? And that kind of information would be very useful, perhaps to create a more competitive market. So more transparency on virtual transactions, on load, on generation, on actual modeling parameters, the topology itself, are critical, really, to address some of these concerns I think you were raising, because, clearly, if there is a specter of inappropriate behavior, that should be really opened up. And transparency should address that concern. It's a concern of ours, as well, not just yours. So thank you.

Question 12: First of all, I agree completely with Speaker 1 that only the ISOs can run the FTR markets, and they're the ones that can match it up, because they set it aside. It is because of the physical nature of it. And the FTRs are very valuable, because it also provides an important role of price discovery for everybody in the industry in terms of getting some sense of what the prices are likely to be. It also provides the benefit of being able to shift the price risk from the ARR holder, if you will, to the FTR holder. So the ARR holder gets the fixed price of the auction award, and then the FTR holder gets that floating price risk.

But I think what I'm hearing here is, there's a dilemma, because revenue is price times volume. And so, while the price risk has been nicely managed, the volume risk is still there. And you don't know a priori exactly what the volume is going to be in total. So the question is, what do you do when you look back at the end of the year? Who do you assign that to? And one way to accomplish that is maybe what PJM is doing today. If they do 85% of the estimate, that effectively gets assigned back to the ARR holders, because you won't have sold the whole amount, and then if there's overfunding, because you're going to basically create an overfunding scenario, it goes back to them. And you don't even have an underfunding scenario anymore. And to me, one answer is that the volume risk then does go back to the ARR holders.

But that seem to be the question. Who should be accepting that risk? And if you're asking the FTR holders to do it, then you're saying, "Well, you have to accept both the price risk and the volume estimate risk as well," which is a more complicated item, and it makes it more complicated on the whole price discovery dimension, because you've added another element to the puzzle that needs to then get managed.

So those are just my thoughts on the process, but it seems to me that that's what the discussion is about is who should be accepting the volume risk. And, to me, the simplest mechanism is just to assign it to the ARR holders, which is effectively what PJM, I think, is doing at the moment.

Moderator: I'll just make just a quick comment on that, which is that I think that a critical point that we haven't really discussed is the interaction between the bilateral markets, like nodal exchange or ICE or bilateral trades between market participants and the FTR market, in that when you have a really liquid FTR market that's facilitated by PJM, and it's in PJM's operational agreement that they have an obligation to facilitate that market, when that happens, it creates a contestable market, relative to the bilateral market, which pushes down the risk premiums in those markets, and it creates increased liquidity, and you see a lot more trading around the time of the annual auctions or around the time of the long term auctions for various market participants who are hedging and trading in the bilateral markets. So I think it's an important aspect that the FTR markets are creating a financial product that actually has more value to the market than just returning the congestion rents to load.

Question 12: If you're looking at the underlying payments to set up and maintain the transmission system, those are allocated based on paths. And so my question is, how do you keep separate the planning process from the ARR allocation/FTR trading regime? I just think that at a certain point, you're building to make those feasible, and I don't know how to keep those processes separate.

Respondent 1: I'm not sure that transmission's actually being paid for on a path basis. And if you're buying networking transmission, it's not related to a particular path. It's related to your area's transmission zone revenue requirements. But I agree that there's not a very good link between a transmission investment and congestion. Transmission investment is profitable in its own right and has advantages over certain other investments for vertically integrated utilities, which is why we're seeing more of it these days. But it's not particularly well-linked. But that's not a flaw either of our proposal or of the alternative. It's a fact that should be addressed. But I agree with you, the disconnect is there.

Question 13: Hi. First of all, I view this panel as like a funnel, and I think that in the last 15 minutes, the real nub of the issues got really crystalized. And it seems to me that one of the nubs of the issues is, what's the purpose of all this? Are we facilitating transactions and complementing the LMP price signals? Or are we just doing a sort of credit to load on their transmission rights, which is almost like a rate making type function you could do? So, Speaker 3, help me reconcile your position with Speaker 1's concerns. You could say the concerns about dampening the LMP signals is just not a concern, and we should look at this as a transmission bill credit, basically.

And then the second issue, which we sort of touched on is, can the financial players essentially be in competition with the load at the front end as to getting these ARRs, etc.? So I'd like to get your views, because it got a little bit lost in there. Thank you.

Respondent 1: I think it's pretty well understood that giving people a lump sum payment after the fact is not going to change the incentives they face. And I'm not worried about that at all. It doesn't blow up the LMP markets at all. I think it's entirely consistent with them. There are a number of ways to implement what we're talking about, and it's no more rate making than the current FTR process. I mean the current FTR process is using 1998 gen to load paths and doing lots of weird things that you could characterize as cost of service. I don't think it's useful to name it in a pejorative way. I mean, they both have aspects of that. So the simple answer is, no, I don't think that our proposal is inconsistent at all with an LMP system. I think it's entirely consistent with it. We like the LMP system. We think it works great. We think it's efficient to continue to function. Am I missing something?

Questioner: And then in terms of financial players' role in all this?

Respondent 1: Some have argued over the years that load shouldn't have any rights to this, and everything should be put up for auction. I'm not sure what people's position is on that, but I do think that the goal of this is to return the congestion revenue to load. That's the fundamental disagreement, which we've clearly crystalized. But I do think that that proposal is entirely consistent with the function of an LMP market. The FTRs are not there to facilitate particular bilateral activities of financial participants. They can figure out a way to do that, no matter what the design is. And I'm sure they will.

Session Two.
Deciding Market Manipulation Cases: FERC Processes, Role of Judiciary, and Policy Coherence

It has been a central theme of regulatory theory that regulators should have a central role in deciding matters within the scope of the Agency jurisdiction. The theory is based on two fundamental premises: 1) the subject matter requires unique expertise that is possessed by a sector regulatory agency; and 2) the central role of the regulators in making sector related decisions makes policy coherence and consistency more likely. In regard to market manipulation cases, however, the Federal Power Act provides for parties subject to allegations of market abuse to select whether to have their cases decided by the FERC, through Administrative Law processes, or to have a de novo proceeding in Federal District Court. In regard to choosing the latter course, recent court decisions have suggested that FERC's views are not entitled to the type of deference which might be accorded them through the ordinary appeals process for other regulatory decisions. What are the implications of these developments? Are we running the risk of having diverse courts making conflicting decisions? Why is the FERC Administrative Process not the preferable option, since it is more likely to produce consistency? Should investigative and enforcement functions be completely walled off from adjudicatory proceedings at the Agency, as they are in rate cases? If courts do conduct de novo proceedings, how much should they be obliged to follow FERC guidelines and precedents in determining what constitutes market manipulation? In terms of market stability and coherence in rules, what is the optimal process for deciding market manipulation cases?

Moderator: As many of you have been involved with HEPG know, we spend a lot of time on the substance of what constitutes or doesn't constitute market manipulation and clarity or lack of clarity in terms of people knowing what the rules are that have to be followed. But this topic is kind of a follow on to those discussions, which is, how do we actually enforce the rules? And it includes some of the issues that are involved with enforcement and some of the questions about the appropriate role for the regulatory agency in enforcing and evolving and exactly how we interpret the market rules and what the role of the courts is. And it's an area where, in part at least, regulatory agencies traditionally have had some of the original jurisdiction over the markets under their jurisdiction. In many ways the way things are set up you could end up having courts with general jurisdiction looking at these questions and case law developing there to interpret the rules.

So the question is for this panel is, how did we get there? What are some of the issues and the process of enforcement that we need to look at? And we're going to look at the history and evolution of this kind of litigation and enforcement action, and then we're going to take a look, from our last speaker on the panel, at the issue of how another regulatory agency with sub jurisdiction in this area, the CFTC (the Commodity Futures Trading Commission), how they view enforcement and how it works there.

Speaker 1.
So, I'm here today to give you the historic perspective on the FERC enforcement process. I

wish I could say that the current process is coherent and seamless. Indeed, for a process to be "due" (and that's what we're talking about here, "due process"), it must be coherent and, by definition, treat the accused fairly and ensure that the accused has an opportunity to defend himself or itself or herself in a timely manner.

Notwithstanding the Commission's efforts over the last 10 years to be fair to respondents and to make the process transparent, the current process is cobbled together and cumbersome, accordingly. Now, partly the reason for the current structure is that, following the enactment of the Energy Policy Act, we built on what we had in place. In retrospect, we probably should have stepped back and built a structure from outside in rather than inside out, given the significant changes to the Commission's mission from that Act. Of course, hindsight is always the best sight. In our defense, we did not truly appreciate the complexity of the dueling statutory schemes, but I'm getting ahead of myself. When FERC became an enforcement agency in 2005, with its new authority to impose million dollar a day penalties, there were three sets of FERC regulations that defined the process for conducting enforcement investigations.

First and foremost, part 1b of the Commission's regulations set out the procedures for the conduct of investigations. These regulations were put in place in 1978. The 1b regulations, for example, provided that investigations will be confidential, limited participation (no interventions allowed), and outlined the procedures for submitting materials. Before 2005, the 1b process was sufficient, because most enforcement actions settled.

Second, Rules 2201 and 2202, found in Part 385 of the Commission's regulations, contained the *Ex Parte* and *Separation of Functions* rules. The Commission issued a Statement of Administrative Policy in 2002 that interpreted and clarified those rules, and there are a few things that the Commission said there are relevant now. For example, unless an investigator is assigned to serve as a litigator, she may freely speak to persons inside the Commission about an investigation, the Order said. Accordingly, the investigator may speak to decision makers and their advisors throughout her investigation up to the point where she may be assigned to be a litigator, providing them with details of the investigation, seeking their input on how to proceed in discussing settlement with them. Proceeding in this way does not compromise the commission's decision making process, the Order continued, because (and this is a quote from the Supreme Court) "the mere exposure to evidence presented in a non-adversary investigative procedure is insufficient in and of itself to impune the fairness of the decision makers at a later adversary hearing."

Before 2005, these rules, as interpreted in 2002, worked well. Again, most enforcement actions and investigations settled. If there was any litigation, and there was some, it was before an ALJ (administrative law judge); thus, the *Separation of Functions* rule kicked in, and then investigative trial stip was walled off from the Commission and its advisors.

So, here's how it worked and how it works, pretty much, today. The enforcement staff would initiate an investigation, perhaps because of a call to the enforcement hotline, a self-report, a report from an ISO or RTO market monitor, or a referral from the market oversight staff at the Agency. The staff would conduct an investigation with depositions, interrogatories and interviews, from which it crafted a recommendation embodied in a memorandum to the Commission. If that recommendation claimed that there was a violation of the law, the

Commission would issue a Shared Cause Order, attaching the staff's memorandum. The respondent would respond, and the Commission would issue an order setting up the next step, for example, setting the matter before an ALJ.

After 2005, the Commission tweaked the relevant regulations and added a few steps in the name of transparency and fairness. And I mean just tweaked. For example, regarding Part 1b, they took two actions.

First, in May of 2008, the Commission issued Order Number 711, which amended the 1b rule. Accordingly, the enforcement staff must notify the respondent that they intend to recommend a Show Cause Order to the Commission. The notification must include information and facts sufficient to enable the respondent to prepare a written response to staff's view, and the staff must give the respondent at least 30 days to prepare that response. Staff must then give to the Commission the respondent's response at the same time it gives their recommendation to the Commission. The Order states that the codification of staff's practice would give respondents, "a fuller opportunity to present their positions with the Commission."

Second, in December of 2009, the Commission issued a policy statement on the disclosure of exculpatory materials which reinforced what staff had done as a matter of practice. Thus, during the course of a 1b investigation, enforcement staff will scrutinize materials it receives from sources other than respondents for material that should be disclosed. Any such materials or information that are not known to be in the respondent's possession must be provided to it. Again, the Commission hopes that the policy would promote administrative efficiency and certainty and contribute to its goal of open and fair investigations and enforcement proceedings.

Regarding the *Ex parte* and *Separation of Functions* rules, there were three actions taken by the Commission during this period. First, in 2007, the Commission issued notice in the *Energy TransferPartners* docket that designated certain enforcement personnel as non-decisional and certain ones as decisional. The Commission's goal was to provide respondents greater assurance that the commissioners would be not unduly influenced by the staff who worked on the investigation. Now, as a practical matter, there was no way for us to figure out who these people were. Over the course of an investigation that could take a couple years, staff come and go. A person could be called in for 10 minutes on one issue, and that would be it. So there was no way for us to know, at the time that that notice was issued, who in fact these people were. So what we did was make the entire enforcement staff non-decisional, so that they could not talk to anybody in the advisory side of the Agency--that includes, especially, the commissioners and their personal advisors. But there was a problem with that. Maybe the commissioners would want to call upon the expertise of the enforcement personnel. So we carved out certain people to be decisional, myself and my four division directors. The Commission has continued with that approach ever since, and it issues that notice when it issues a Show Cause Order.

Second, in 2008, the Commission issued Order number 718, which codified what the Commission had said in 2002, that the *Ex Parte* and *Separation of Functions* rules are triggered when the Commission establishes, and only when the Commission establishes, a trial-type hearing for the purpose of litigating a matter arising out of an investigation. However, a significant amount of communication takes place before a case is ever set for a trial-type hearing. In fact, way before, there was a recommendation on a Show Cause Order, and, more important, not all enforcement litigation takes place before an ALJ. In fact, only 25 percent of the market manipulation cases that have gone beyond a settlement, or have not settled, have gone the route of an ALJ. So for 75 percent of the market manipulation cases, Order Number 718 is irrelevant.

Finally, in the 2008 Revised Policy Statement on Enforcement, the Commission stated, as a matter of policy, that Commissioners and their personal staffs will no longer accept oral communications about pending investigations from respondents. Such communications would have to be in writing. Now, this statement is lopsided. I have to admit that when I was head of enforcement, I liked this statement, because it kept the people from the outside from talking to the principals. But it's lopsided, because it doesn't say anything about the enforcement staff talking to the Commissioners. I was both the inside cop and the outside cop during my career at FERC, and as former officer of the ethics agency, it's a totally unenforceable sentiment. Even I wouldn't have tried to enforce that against my boss.

I'd like, now, to return to my original point about the process not being coherent. And there are two reasons, both of which are grounded in the statute: the difference between the process for assessing penalties in the Gas Act and the Power Act, and the convoluted approach found in the Power Act. Now, by way of background, in December, 2006, the Commission issued a Statement of Administrative Policy regarding the assessment penalties under the Power Act and also the Natural Gas Policy Act (NGA). The main issue is relevant to market manipulation. It was and is whether the respondents in an investigation can have their cases tried de novo in a U.S. District Court or have them heard at the Agency before an ALJ. In 2006, the Commission read the Natural Gas Act to say, "No way," and the Power Act to say, "Either way." With respect to the NGA, the Commission reasoned that the Congress did not establish a de novo court review and the Commission could not provide what can only be provided by congressional action. Therefore, respondents in a Natural Gas Act investigation could have their cases tried only at the Agency following the traditional approach of setting the matter for hearing before an ALJ, who would issue an initial decision on which the Commission would opine in an order subject to rehearing, and an order on rehearing, and, finally, which would be reviewed by a U.S. Court of Appeals.

With respect to the Power Act, the Commission recognized that the statute specifically referred to a process already in place for violations of Part One, that's hydropower licensing, and applied that process to violations of Part Two, market manipulation provisions. Therefore, respondents in Federal Power Act investigations could have their cases tried either by an Agency ALJ, with judicial review by a U.S. Court of Appeals, or in a U.S. District Court, with eventual judicial review by a U.S. Court of Appeals.

No one, I repeat, no one--no company, no law firm, no trade association, no state commission, no former general counsel--no one sought rehearing of the policy statement. In other words, no one challenged the Commission's reading of the Gas Act and the Power Act.

The dichotomy, unfortunately, between the Commission's approaches to the enforcement of its market manipulation rules, which are basically the same for gas and electric, has significant ramifications. Obviously, a trial conducted by a different type of judge with a different mandate will likely lead to a difference in the development of the law on manipulation, even though that law should be the same for gas and electricity. For gas, a FERC ALJ will understandably be inclined to give great deference to what the Commission has already said. That's what FERC ALJ's are supposed to do--follow what the Commission has said. Moreover, once the Commission has addressed the case and there is a final opinion on an ALJ initial decision, under the Gas Act, a U.S. Court of Appeals must give deference to the Commission if its decision is based on "Substantial evidence in the record." That's statutory. Lastly, up to the time a gas case goes to the Court of Appeals, the Commission controls the timing. It can decide when to set a matter for hearing, when it issues an opinion, when it acts on rehearing. However, the respondent will control which Court of Appeals the case is heard in.

Now, for electric, a U.S. District Court Judge would be expected to approach the case based on what is presented. That is, a District Court Judge does not have the same obligation to the commission that a FERC ALJ does. Granted, his or her decision would be appealable to a U.S. Court of Appeals, but that court does not owe the Commission the same deference as if it would if the case had evolved under the judicial review provision of the Act. Once the case goes to a District Court, the Commission loses control over the timing of how it proceeds; however, the Commission controls which District Court the case is filed in to begin with.

So, is your head spinning? Unfortunately, it is not rocket science to see how the law regarding manipulation of natural gas versus the electric energy markets could develop differently over time--and talk about confusing! And I think this is a disservice to the markets which the law is intended to protect.

The second reason that the current FERC enforcement process is not coherent is the convoluted approach to litigation in the Power Act. To be frank, none of us in the development of the 2006 administrative policy statement foresaw a tension in the language, tension that immediately triggers due process concerns. For a respondent in an electric case to get to the District Court, the Commission must first assess its penalty, which the respondent refuses to pay, and the Commission takes the respondent to court to get its money. It's like going to court to collect on a judgment. Now, here's the rub. The judgment is the Commission's decision assessing penalties based on a written record rendered after the Commission has issued a Cause Order and received responses. Now, however, the record developed from that point forward, and for sure the record compiled previously, has not been tested to ensure its validity. The respondent has no opportunity to subpoena records or cross examine witnesses. Now, to be sure, the Commission frequently hears cases on paper. Every lawyer in this room knows that, and all the non-lawyers as well. And in fact, the Commission has been upheld many times, when it has heard a matter on paper. However, the Commission itself has always forgone paper hearings when the demeanor of a witness is important to the proper resolution of the issues, and market manipulation clearly falls into that category. So, as a practical matter, once a respondent in an electric market manipulation case has chosen the District Court route, and they all have, it can expect the Commission to issue promptly its decision on whether and to what extent to assess a penalty for violations of the law. There is no time, really, for any kind of a hearing.

And this is the part that I find so convoluted. It puts a respondent between a rock and a hard place, and, truthfully, I didn't see it until it started to play out in real life. Then I thought, well, it's not such a big deal. It's not such a big deal, because they're going to go to District

Court and they're going to get a trial *de novo*, so everything will be fine; it will not be just a summary review of what the Commission said. So I didn't feel so bad, in retrospect, that maybe I wasn't so alert when I was head of enforcement.

The Commission had said, in 2002, in that statement, that investigations are not adversarial proceedings. No one was more surprised that I was when the enforcement staff started to say, last year in court pleadings, that the Agency proceedings were actually adversarial, at least after the issuance of Show Cause Order, and that the Court should simply review the FERC action and not conduct a trial *de novo*. It was as if describing the first action as adversarial just magically turned it into the functional equivalent of a trial. Trust me, none of us, none of us in 2006, when that administrative statement was issued, my staff and myself, as well as the general counsel and his staff, and, I think it's fair to say, the Commissioners, viewed *de novo* that way. I gave speeches all over the country about it. And what was really surprising and very disappointing was the Commission's endorsement of the staff's position in the *Coaltrain Energy* Order. I'll leave it to my fellow panelists to discuss how the courts have reacted to this version of history, and I thank you very much for your attention.

Speaker 2.

Let me try and just address a couple of aspects of the question that Speaker 1 teed up. I could talk about it for hours, but you'd be bored, and we have limited time, and I assume, later on, we'll be covering different things.

To me, it's useful to look at the Commission's Power Act enforcement statutory process in historical context, and that, I think, brings into sharper relief what Congress meant. It's kind of a peculiar structure, because some of you may have read the recent mainstream press about the FTC and SEC trying to guide their enforcement cases about securities fraud to their internal courts, because they think they'll have a better shot, and litigants are fighting about that, and that's because those agencies, now, anyway have the statutory right to choose the forum. And there are questions about whether that's constitutional, and everything like that.

You have other agencies that have always had to go to court, because that's what the deal is. The actual Natural Gas Policy Act of 1978 works that way. So if there's an enforcement proceeding there, FERC has to go to court and try to get a penalty assessment reviewed *de novo* and collect the money. The Power Act did something different by giving the defendant this kind of field of his choice. You can take an adjudication in front of an ALJ under the Administrative Procedures Act, meaning all sorts of technical things and rights and obligations follow, or you can have a provision for review *de novo* in court, and there were two statutes, actually, that had that structure that are part of Jimmy Carter's war on energy that nobody's really ever paid attention to. So probably some congressional aide knew about that and said, in 1986 when this statutory language was put in, "Well, let's do the same thing." And a year or two later the Atomic Energy Act picked up the same language. And now we're fighting about what it means if you elect the court action.

But let's go back and see how the administrative state evolved through time prior to 1986 and how courts and administrative law scholars viewed the authority of an agency to impose penalties and adjudicate them virtually through the authority of courts and, you know, how did we get there?

Since the days of Merry Old England, really, the sovereign might extract civil penalties from the subject or company, but you had to go to a court and have an action in law, and there's a right to jury (and it always amused me, but American courts will sometimes look to see what type of process the British courts used, prior to our founding of the republic to figure out what they should do). So the court said, "Well, we have to have a jury trial and this stuff goes to Federal District Court. And you have an action just like any normal civil action." Now, that was all created before administrative agencies existed. We're talking about the 19th century.

Eventually, in the 20th century, Congress started inventing these things called agencies. And they've since multiplied, they've grown up like top seed, they're all over the place, and they all have these alphabet soup names, and there's gazillions of them. And their power has grown massively, but it wasn't always that way. Originally, there was the sense, among other things that having these agencies would create the policy coherence that this mission statement talks about in regulation, though it bears noting that, when it comes to federal regulation, electricity coherence is handicapped from the outset because, as the Supreme Court observed in the 1940's, it doesn't make a whole hell of a lot of sense for Congress to have given the production function to the States to regulate, and the middle man function to the Federal government. Wholesale sales and interstate transport and then the distribution function is staged to the States, and you don't need to look any further than last term's Supreme Court decisions to talk about Federal and State authority and how confusing all this is.

Putting that aside, agencies grew through time, and they were supposed to, among other things, give this policy coherence across the Federal government where their authority allowed them to reach. But to begin with, and as we move through time in the 40's, 50's, 60's, there were no civil penalties. There was a broad suspicion that having administrative agencies actually adjudicate those questions would be unconstitutional. The Supreme Court upheld that you needed a jury trial, and, obviously, agencies aren't going to do that, and it was only in 1977 that the Supreme Court said, "Yes, agencies can adjudicate civil penalties." And that came about because of this organization called the Administrative Conference of the United States, or ACUS, that is sort of a self-selecting group of administrative law scholars, people who generally actually are in favor of the administrative state and think agencies are a good thing (and nowadays, by the way, there are some in legal academia who say agencies are unlawful, they really can't exist). But in the 1970's, we were sort of at a point where the vanguard of administrative action was really rolling out in force, and there were some reports, the first one was in 1972, about six months after the Watergate break-in in this very hotel. And a professor wrote this article and he said, you know, we should let agencies do more of this stuff. I mean, people like the Coast Guard and the like, they've got all these little tiny cases, and it's clogging up the courts. The Coast Guard has got to say, "Well, gosh, somebody gave a speeding ticket to some pleasure boat, and it's $125.00 and he won't pay it. So, Department of Justice, will you please sue this guy?" And, surprise, surprise, that didn't always happen, because DOJ would have better things to do, and so the thought was, well, agencies can do this. At that point in time the notion was, well, if they're going to do this, you either have to have the courts come in and have a real adjudicative function there, but eventually the notion came to be that you could have an on the record ALJ trial, and maybe that works sometimes, at least when you have not that much in the way of dollars at stake, and people talked about

$10,000.00, $5,000.00…eventually, in the 80's, $25,000.00…nothing like in a Barclays' case, where the Agency wants half a billion dollars. So, generally, these were the little small fry cases.

But the notion that you could have agency adjudication was also the notion that you had to have adjudication somewhere. You couldn't, other than the tiniest cases, have a lack of process, because the courts and the scholars call civil penalties a "quasi-criminal sanction." It's not criminal. It's kind of as close as the government gets, and these cases can, frankly, ruin the lives of individuals, and they can cost companies huge amounts of money. So this is an area where you need an adjudication somewhere, the scholars said, but in a big case it should be in court, and in fact they didn't know about EPAct 2005, but they did say that in 10b-5 cases where fraud is at stake, you need to go to court there, and you're going to have questions about intent and fraud, and courts are used to doing that. So Congress enacted this almost unique structure, giving the target the selection right, and we would say that it's a selection between adjudication at FERC with traditional judicial review in a Court of Appeals after a FERC decision and rehearing, or traditional adjudication in court, and then we have this fight now about what the court action really means, and I think ultimately the defense side will win. It may take a little while. And we'll talk more about what's going on in litigation, I'm sure, as we move on.

The last thing I want to note, though, is, when and where does this actually matter? Because there can be a fight, even in cases where the courts have said the defense is right about what the court action means, about, well, does FERC get deference to any of its legal conclusions? And we argue no, because Congress can turn off Chevron deference, and they did that here by scripting *de novo* review. But there's another side to that question. I would advance the hypothesis that that matters, but it doesn't matter hugely, because, as the late Justice Scalia used to say (and as other courts have said, too), deference doesn't come into play all the time. It only comes into play if the statutes are ambiguous.

And so FERC can't go outside on a beautiful day today and say, "The sky is green, your Honor," and expect to win, because we can all see the sky is blue. You can't say the word means something it just doesn't mean and get deference. You've got to show that there are plausible interpretations, and if you have ambiguity and you're the government, you try to play that card, you run into another problem because there are cases from the Supreme Court and other courts saying that the government can't impose sanctions for violating ambiguous legal provisions, because that's not fair. Nobody knew what the law was. And so, to get deference, FERC has to kind of almost plead themselves into a constitutional impairment. FERC could argue for deference even in a traditional civil action, so they don't have to win everything they want to win. They can have that be an issue that can be contested.

I would submit to you that the better question, the more dangerous question, and the reason I think that people keep electing court review even knowing FERC was going to argue…(and, mind you, in Barclays we didn't know what FERC was going to argue. That was a bit of a surprise.) There are various reasons for electing court review, but one of the most important reasons is FERC getting deference on factual issues. Because, as Speaker 1 noted, "substantial evidence" is kind of a watered down standard. It's less than half. So, you could be on the losing side of a proposition, as the government, and you could still win. So, if you're the defense, you never have a fair fight. You never get that 51 percent victory, and you go down in flames, maybe to the tune of really serious, life altering outcomes, bankruptcy outcomes, and since criminal cases can pile on top of these things, who knows what the possibilities are. And so, if you pick the DOJ option, you end up routed to an area where FERC might get affirmed, even though they really should have lost in court. And if you pick the court option, the statutory language talks about *de novo* review of the facts and the law. You would think the one thing that would mean is that if the court's going to take a fresh look at the facts, it sort of doesn't matter much at all what FERC says about the facts, because you're taking a fresh look. And that all works pretty well, from defense perspective.

There's a fight about whether you get to put in new facts in or not. The answer needs to be that you can, but even if you're just fighting about the so called record that existed before, if the judge is going to say, "All right, do I believe this fellow and what he said he was trying to do with these trades? Do I believe his explanation of this or not?" FERC statements don't matter.

Interestingly, though, in the litigation that we see now going on in the Barclay's case, for example, FERC filed a 20-page Motion for Affirmance of its 500-million-dollar sanction (25 million dollars a page). And the way they did that is there was a 130-page single spaced Penalty Assessment Order with about 200 footnotes that they issued. They kept saying that FERC recently found that because the person was lying about X, Y, Z, therefore this was the intent of the trades, and they'd cite huge portions of their Penalty Assessment Order, and why would that matter? It seems to me the real question is, actually, will FERC, in some Trojan Horse way, somehow get factual deference? That's really where the rubber meets the road.

And, finally, it just seems to me that Speaker 1's point ends up ringing true to most people. You should get your day in court somewhere. And it's a strange world, to imagine that you could have a finding about somebody's intent. What was in your heart, you know, when you did X, Y and Z? What did you mean in this goofy email? Who knows? …and to have a decision maker decide what the answer to that question is, never looking that person in the eyes, as juries like to do and judges like to do, is a strange thing, and not, I would say, what Congress could have possibly intended, but we've got a real fight about this. The courts have agreed in two cases with our point of view, and in other cases that I'm going to be involved in, the jury's still out.

But, finally, on the question of policy coherence, the courts eventually iron this stuff out. It may take a while. Yes, you could have these questions like "what is manipulation?" litigated in a bunch of different forums, and you'll go up to the Court of Appeals. Maybe they'll agree with each other. Maybe this will have to go to the Supreme Court. Or, "What is fraud in the Commission's anti-manipulation statute?" And those questions have existed each time Congress passed statutes like that. They existed when Congress passed 10b-5, and so there'll be a shakeout period, but I think the objective of policy coherence, by giving the Agency a larger role, may have its place, but not fairly or lawfully when it comes to adjudicating civil penalties over the objection of the targets.

Speaker 3.

This is the Harvard Electricity Policy Group, so I want to sort of address the legal issues, but, more importantly, the policy question that I think this panel really raises, which is, should market manipulation cases be litigated in federal court or at the FERC, because the argument certainly can be made that there will be "better" coherent economic and enforcement case decisions if an agency with special expertise is making the decisions. And so the question I really want to raise is, one, is it necessary for policy coherence? That is to say, evaluating this from both an economic perspective as to what is a proper interpretation of market manipulation, and balancing that with a proper role for government and enforcement in terms of thinking about whether these cases should be litigated either at the FERC or in federal court.

In thinking about whether they should be litigated at the FERC, we have to understand a couple things that we delved into somewhat already. How are the FERC cases currently litigated? What are the current flaws in the current FERC enforcement process? And then, if we find there are flaws in the FERC enforcement process that can't be fixed, can the federal courts litigate these issues in a coherent way that makes sense from both an economic and enforcement perspective?

And since we're at Harvard, we solve for problems. I submit that there are three sets of problems that we have to address if we want to determine that the FERC in-house process is the preferred route: structural problems, procedural problems, and substantive problems.

So, we've gone through this already a little bit, and Speaker 1 laid this out. It's a mismatch between how the cases are litigated under the various FERC statutes. Under the Federal Power Act, as Speaker 1 & 2 mentioned, you get an election. And the court in *Maxim Power* and in *City Power* has said that that election if you take it in federal court, means a full trial *de novo* subject to normal Rules of Civil Procedure. Out of every respondent that has had the election to take a federal court process or FERC, all but one has taken the federal court process. And in the only time that the person took the ALJ process, the person had admitted to all the facts, so there was nothing to really adjudicate. So, anytime there's been any real factual dispute, every election has gone to federal court.

Then we have the Natural Gas Policy Act that we talked about, which had the *de novo* review language that mirrors the election for federal court review of the Power Act, and then we have this question of the Gas Act, which is silent on the procedure, as to whether, under the Gas Act, the FERC is required to have a trial *de novo* in federal court, or whether they can use an in-house process. Our position is quite clear that under Section 24 of the Gas Act the Commission must litigate those cases in federal court. That's not a topic we need to get to today, but I do want to at least mention that there is this mismatch in all the cases.

So now we get to, what are the flaws in the FERC process? And I really want everybody to focus on this language in the *Maxim* case. We litigated this whole question of *de novo* review in the *Maxim* case, which just settled a couple weeks ago. And we finally got a judge, for the first time, to actually adjudicate what the words "*de novo* review" meant, since the FERC has changed its position. Remember as Speakers 1 and 2 said, we all thought, coming out of the policy statement, that "*de novo* review" meant *de novo* review. There was a First Circuit case right on point. FERC decided, "No, we're going to change our view of that." Fair enough. So, we finally got a judge to address that, and the judge (Mastroianni) in Massachusetts federal court found that "*de novo* review" meant a full trial on the merits.

But what I really want to point out is this language here. He talked about and this again. This is an Obama-appointed federal judge, a fairly new judge who had been both a prosecutor in his earlier career and a defense lawyer, somebody who had been on both sides of the street, an Obama appointee, and he says, "the simple fact that the Commissioners perform both investigatory and adjudicatory functions in the same case risks an inherent bias in the decision-making process, even if that bias is entirely unintentional and even if the 'combination of functions does not alone violate due process.'" So here we have a federal judge saying that there's an inherent risk. He's not saying anybody's acting in bad faith. He's not saying anybody's not doing their job, but he just says that the process that the FERC goes through raises an inherent risk of bias. That, to me, is quite important. And so, when you think about all these various issues that we're going to talk about you have to overcome the structural flaw in the FERC process that this judge quite properly recognized, raises an inherent risk of bias in the outcome of the proceedings.

As we go through my talk in this panel, I will submit to you that it's not entirely clear to me that there is anything we can do short of a statutory change that will fundamentally cure that inherent risk of bias. And until we figure out how to cure that "inherent risk of bias" (again, Judge Mastroianni's words, not mine), I don't know that we can actually have the fully fair due process proceedings at the FERC.

In addition to the due process problems, we've talked a lot at Harvard over the years about the proper definition of market manipulation. I think we've had five or six full sessions about that over the last five or 10 years. And yet, here we are still; we don't have a coherent definition at FERC as to what constitutes market manipulation. For example, FERC does not recognize, in any coherent way, any sufficiently rational way, the difference between market manipulation and market power. They consistently conflate the two in their enforcement cases. And the reason that is problematic for the FERC is that the Congress, in 2005, gave FERC this new manipulation authority, based upon the SEC Statute 10b-5 where one must prove fraud. And yet, in a number of these enforcement cases that we're litigating, they are market power cases, not fraud cases. And so we've come up with this phrase, "Well, these are non-fraud fraud cases." And then we sort of say to the staff, "Where's the market share analysis?" Right? You know, you start to say there should be an HHI (Herfindahl-Hirschman Index) market concentration analysis. There should be a market share analysis. Something. There's no coherent definition of market power. There's no clear definition of market manipulation and no distinction between the two.

The second problem we have about this is that, despite the fact that their statute is based on the SEC statute, the FERC rejects the SEC case law and the SEC findings about the "but for" test. And you see it laid out there on the slide. I don't need to go into it in great detail. The courts have said, and the SEC has followed this, that there's a "but for" test that say that "but for the manipulative intent, the defendant would not have conducted the transaction." If there was a lawful intent, even if it was combined with an unlawful intent, that is not actionable under the SEC Statute, under 10b-5. And despite the fact that FERC has said, "We're going to follow the SEC case law," the FERC has rejected this.

And so, as we go through and think about whether FERC can address these issues, these are some of the fundamental structural, procedural, and due process questions that we have to resolve before we can even get to the question of whether FERC is equipped to do these adjudications.

So then we go to the flip side. Can the federal courts, coherently adjudicate these cases? And I would submit to you that the answer is yes. We have seen over the years that the federal courts have been quite adept at addressing these questions. They've been dealing with fraud-based manipulation under the Commodities Exchange Act and the Securities Act for many, many years. There's a very, very well developed case law, and you see FERC itself seems to acknowledge that that case law can be quite useful in interpreting what the statutory requirements might be.

And as we saw in Order 670, FERC has said that. And they've said it time and time again. And they said they will follow the general case law. Unfortunately, as we now know, that has not been the case. We've seen recently in these two cases, *Maxim Power* and *City Power,* that the court seems to be quite able to interpret the statutes. (I say that only because they agreed with me.) But this is not a new issue. The courts have been interpreting what constitutes market manipulation and market power for many, many years. You'll see here the court in *Maxim Power* really understood the point Speaker 1 was making, that there is no adversarial process during the investigatory stage at FERC. It's an investigation. The investigators have subpoena authority. They're not issuing discovery requests. They're issuing subpoenas. You don't get to say, "I'm not showing up," unless you want to go to federal court and fight it. It is not a true adversarial proceeding. And as you see, here's a federal judge again, an Obama appointee. (I want to keep stressing an Obama appointee.) We said that it wasn't an adversarial proceeding. There's no right for the defendant to have discovery. There's no right for the defendant to depose the witnesses that were being used against them. They had no rights that would be normally attendant in an adversarial process.

So then the question I want to get to is, can we fix these problems? And I just want to get to the point Speaker 2 was making. Here are the raw statistics. Why did the SEC all of a sudden decide to go to in-house proceedings? Because they win. Wow. This just in. There's gambling going on. They win 90 percent of their cases when they go in-house. Now, their batting average is still pretty good when they go to federal court--70 percent. But they decided they'd rather have 90 than 70. Well, that's probably logical. FERC gets 100 percent. Well, actually not. FERC has only lost an enforcement case once before an ALJ. Only once. So their batting average is even higher than the SEC's, in-house. So, when you have, as the court in *Maxim* found, a structural problem, it is just not entirely clear to me that you can fix the problem. And, as Speaker 1 mentioned, one of the structural problems is the that ALJs are "inferior officers." (Not my words, this is the Commission's own words.) The Commission determines what market manipulation is. The Commission determines what market power is. The Commission determines what the facts are in the case. The Commission itself has told the judges, "Follow what we say, you're not independent. You are not independent. You do not have the latitude to change what we do." So, if I'm before a FERC ALJ and I say, "I don't agree with that, the Commission's view of what constitutes market manipulation," the judge says, "Sorry. I have to follow what the Commission says. You do not get to make separate arguments as to what constitutes market manipulation." This is in a recent oil pipeline case, where Judge Johnson, three times tried to change the policy that she thought was wrong, and three times she was told, "You follow what we say." Judge Johnson is now retired from the FERC.

Another structural problem I don't know how to fix is the *ex parte* problem. This is really quite problematic. The problem is that, during the investigatory stage of the proceeding, which is really 99.9 percent of it, the investigatory staff and the advisory staff and the Commission have unfettered communications on the merits of the cases. Back and forth. No record. No determination of what is in and out. These are the words of Larry Parkinson before the Congress, under oath. They consider all these communications to go to the "merits of the investigation" and that "candid back-and-forth" between the Commissioners and the advisory staff are essential. No record. No idea what's been told to the Commissioners about the case. No idea of what's been presented to the Commission.

I used this example about an FBI agent before the Congress a couple years ago when I was testifying on these issues, and I'd like to use it again, because my theory is that even the Democrats on the Congressional Committee understood this, so I'm quite sure people at Harvard can. So, I want you to imagine FBI agents spends years investigating the Hogan Electric Company for possible market manipulation and the violation of electric law. And after investigating the case for a number of years, the agent decides to change gears and become a law clerk for a federal judge. Well, then, lo and behold, the Judge that this agent turned law clerk is clerking for gets assigned the case to adjudicate whether the Hogan Electric Company has violated federal law. The law clerk doesn't recuse himself. Even though he was the agent on the case, he doesn't recuse himself. He advises the judge, who then issues a number of rulings about the case, for years and years and years, about whether the Hogan Electric Company has violated the law and what due process is observed. And then, one day, the agent turned law clerk decides to change career again and goes to the prosecutor's office and prosecutes the Hogan Electric Company, never once recusing himself from any matter. Now, would anybody in their right mind think that comported with due process? Of course not. That is the FERC process today. Nobody would think what I've just described comports with due process.

And so this is really a very important structural problem. Can we fix the *Ex Parte* rule? Well, it seems to me we have one or two choices. We can trigger the *ex parte* rules much earlier in the process. I don't know about the commissioners, but the FERC staff has testified that they're very much against this; that it would impede their enforcement function. I don't quite understand that, but that's what their position is. Or do we just open the process up completely and allow respondents in cases to talk to the commissioners about enforcement cases during the investigatory stage at any point? Right now, the policy of the FERC is that during the investigatory stage, you can send written comments in to the commissioners about your case. During settlement negotiations, you can send paper to the Commission, but you can't talk to them. You cannot talk to the decision maker. Only the enforcement staff can. That's very one sided, in my view. So, we either have to apply the *ex parte* rules much earlier, or we say, because there are no parties in the investigations, the defendant gets the same right to talk to the commissioners as the enforcement staff. I personally would welcome that. I like to fight on the merits. So, if I have the ability to actually sit and talk to a commissioner about an enforcement matter, I'd like the ability to convince them that I'm right and not have to just have plain paper, which, by the way, the enforcement staff gets to respond to without me ever knowing what's in it. And so this is really an important structural problem that I don't know how to deal with.

I've written a lot about and talked a lot about these procedural problems. It's all laid out here, but I'll go through them quickly. The FERC does not consistently apply their *Brady* standard in enforcement cases about what constitutes exculpatory information and when it should be disclosed. When we have these ALJ hearings at the FERC, the Commission is not required to follow the Federal Rules of Civil Procedure or the Federal Rules of Evidence. And, with no disrespect to any member of the FERC staff, the current case law at FERC is that, if you have a FERC badge, if you literally have a FERC badge, you qualify as an expert in an ALJ trial on any subject. How do I know that? Because I litigated that issue, and I actually got an ALJ, about seven or eight years ago, (this was in a rate case) to find that a FERC person was not an expert on a cost of service issue. The judge said, "You're right. They don't meet any of the Federal Rules of Evidence expert qualifications." It took the FERC two days to reverse the judge, saying, "That person has a FERC badge. They're qualified." Now, that may be OK for rate cases, I guess, but in cases where there's hundreds of millions of dollars at stake, where there's very significant economic testimony that's got to be litigated, is that really the right approach? And so we don't have the Federal Rules of Evidence. We don't have the *Brady* standard. We don't have the normal rules apply.

And then, turning to substandive problems, what constitutes "market manipulation?" The FERC, as we all know, doesn't really define it, other than, as you see in that first bullet, saying that fraud based manipulation is anything that impairs, obstructs or defeats a well-functioning market. I submit to you that that does not constitute fair notice, does not constitute any form of due process. It is in the classic Justice Douglas school of, "We know it when we see it."

Again, it doesn't distinguish between market power and market manipulation. If anybody's really interested in this, Craig Pirrong wrote a really very good piece on this in the *Energy Law Journal* a couple years ago, on how the FERC and the CFTC and the FTC were not properly recognizing the distinction between market manipulation and market power issues. It's really well done, if you really want to delve into these issues in any detail. But you'll see, we have all these problems.

And so I'm going to end by saying that I think we have to leave these cases in federal court. I think the federal courts are more than capable of putting coherent and economic decisions together. They've done so for many, many years. I don't think, absent an active Congress, that we can fix the structural problems, procedural problems, and due process problems at FERC. Maybe we can. I don't think so. And so I would leave everybody with the notion that the answer to the question posed to the panel is, these cases should stay in federal court. Thank you.

Question: Speaker 3, I guess I'm wondering, just on your last point, if the courts were adjudicating, would that restrict the amount of discovery that would happen before the case is brought? That is, would it limit discovery during the inquiry phase or even the investigative phase, so that they could develop kind of a record through the normal FERC process, where some of those cases might ultimately get dropped, where they're just trying to figure out what went on, or would just everything have to go through the court?

Speaker 3: This is the problem. There is no discovery at the FERC. It's an investigatory process. The FERC gets to issue subpoenas. The FERC gets to take that position. The FERC gets to build whatever it wants. The defendant doesn't get to do any of that. So when you get the record to court, OK, now there are rules in federal court that do restrict how much discovery you can take and when you get to take it, but I would much rather be in that venue than not have any discovery at all at FERC.

Questioner: Yes, but if we imagine a world in which this became clear in the way that the defense in these cases is requesting, then FERC really can't decide things. You will see them, I think, in relatively short order, once that is certain as an outcome, change their process a lot. Because why should they issue 150 page single spaced orders with 150 footnotes trying to decide things if their decisions don't amount to anything? They'll collapse their process. They may do that anyway, because their process is kind of unyielding.

Moderator: But I do want to point one thing. In the *Maxim* order, where the judge said that they had to go to federal court and they had to take discovery, the Judge very explicitly said to FERC, "You don't get to duplicate what you've already done. So, if you've asked, through your investigatory process, the equivalent of discovery, and taken depositions of people, you don't get to do that all over again." And I think that's an important point that should be listed. And that, to me, is a quite clear recognition that this judge understood how one-sided the process was before the case got to him.

Questioner: And so the enforcement staff would still be able to sort of look through all of the evidence to decide whether to bring the case or not, but then ultimately be judged by the Court.

Question: The statutes provide for different processes, and I can't tell, Speaker 3, whether you think the fact that the process is different is somehow inherently unfair, and that's what Congress needs to act on--to establish one consistent process? Is the difference in the statutes part of your objection, or do you think FERC has tried to manage those differences unfairly?

Speaker 3: Well, I wasn't really getting into the differences between the statutes. We could, but it's --

Questioner: But Speaker 1 seemed to somehow stress that the incoherence is in part drawn from the fact that the statutes provide for different processes. I can see how it's confusing from the point of view of regulated entity. I don't think it's necessarily incoherent, if there's actually a cause for the differences.

Speaker 1: Just because there's a cause for the difference doesn't mean it's not incoherent. Obviously, the cause that was laid out was the difference in the way the statutes were written, or at least the way they were interpreted in 2006. But the dichotomy between the two has really created these two very different processes with different judges at different times, and I think that is incoherent and inherently bad, wrong, dangerous to the markets that the laws were intended to protect. I really do think the difference in the statutes is the nub of the problem, or one of the nubs of the problem.

Speaker 3: If you just think about it in very simple terms, if the FERC can impose a 500-million-dollar civil penalty under the Gas Act, and you have no right to federal court, and it can impose a 500-million-dollar civil penalty under the Power Act, and you get to go to federal court with all this additional due process, is that really what Congress would have intended had they understood that? And it's our view in the *Total* case that, when they added the election in the 1986 in the Power Act, Section 24 of the Gas Act was already in place that said violations of the Act are subject to the exclusive jurisdiction of the federal courts. By not changing that to provide for ALJ process under the Gas Act, it is our view that the Congress, back in 1938, (and I was not there) [LAUGHTER] specifically left those decisions up to the federal District Court. So, I don't think it's the difference in the statutes that ends the policy, it's the fact that the FERC itself has, in my view, misinterpreted the Gas Act.

Question: So you think FERC should have read the federal power provisions into the Gas Act?

Speaker 3: No. Just the opposite. I think the Federal Power Act came along and gave FERC, for the first time, the ALJ route in '86. There had been nothing before the Power Act that gave people the right to do ALJ hearings. So, in our view, under the Power Act and the Gas Act they had Section 24 which said that violations of the Act must go to federal court. Congress specifically carved out, in the Power Act, an exception to that to say, but if you want to go to an ALJ, you can go to an ALJ. They did not do that for the Gas Act, and that, to me, is where FERC is misreading the statute.

Question: The second clarifying question is just on the *ex parte* issue. Is there any federal agency that does what you propose--your alternative solution of ready access to the leadership, the Commissioners, anytime? Which agencies do that?

Speaker 3: The SEC. You can go into the SEC commissioner's office anytime. The difference, though, in the SEC process is that the enforcement process at the SEC is much more walled off. Even the CFTC process is more than FERC. In the SEC process, the head of enforcement doesn't go marching up to the SEC commissioners every day and have conversations about cases. There are quarterly reports. There's much more of an arm's length relationship in the SEC between the enforcement division and the commissioners. I'm not saying it's perfect. I would not say that it comports with due process, what they do, but there's at least much more of a separation of functions at the SEC.

Question: I'd like to address a couple of those. Speaker 3, you're absolutely wrong with respect to the CFTC and the *ex parte* restrictions on enforcement staff. We've had discussions with the staff over there. They have indicated that under no circumstances would their commissioner meet with a subject of an ongoing investigation while that investigation is going on. So in that sense the FERC process and the policy statement is absolutely no different than what the practice is at the CFTC, according to the enforcement staff we've discussed that with.

Speaker 3: Then a recent meeting we've had was obviously a violation of that.

Questioner: It's not consistent with what the enforcement staff over there has told us their approach is with their commissioners.

Secondly, I just want to clarify, you mentioned a couple of times that there is no right to federal review under the Natural Gas Act (NGA) process. I would say there is absolutely a right to a federal review. Brian Hunter can confirm that. Through the process set up in the NGA, you get to take the Commission's decision up to review by the Court of Appeals, just as you could with any other ALJ process of the Commission. So I agree it's not the same as a trial process or a *de novo* review process that might have happened in federal District Court, but there is the opportunity for federal review of the Agency's actions.

Speaker 3: But, importantly, in that one instance, where the DC Circuit reversed FERC, it was purely on a jurisdictional ground. It was not on any legal ground. It was not on any of the factual issues that Speaker 2 raised. We never got to any of those issues. So, to my mind, that is not a good answer. If we have purely legal issues, then what Speaker 2 said about deference is quite apt, which is that the courts are pretty good at trying to understand whether FERC is following the statutes. Chevron deference, the one step, two step, you know it as well as anybody. That doesn't worry me as much. So, the *Hunter* case, to me, is not a very good example, because that was a purely legal jurisdiction question.

Questioner: No, but I think you have to be clear what we're talking about. When you say there's no opportunity for federal review, that's simply not the same …

Speaker 3: There's opportunity for Federal reviews subject to deference…

Questioner: That's not what you said, though.

Speaker 3: And what I would submit to you is that when you have 100s of millions of dollars in penalties, FERC should not get deference, period.

Questioner: That's fair enough. I'm just clarifying the point that you had made earlier.

Moderator: Let's turn from FERC to the Commodities Futures Trading Commission and get some perspective on enforcement there.

Speaker 4.

I'm going to talk about CFTC enforcement process and procedures, and there are some similarities and some differences with FERC. These are different agencies, with, obviously, different institutional histories and lore and whatever. Although their legal structure is different, I think there are some lessons that can be drawn from the way the CFTC has approached this.

In the CFTC world, under the Commodity Exchange Act, it's really up to the CFTC which forum to proceed in. The respondent or defendant doesn't have the choice. It's the Agency's choice. Today, the Agency can choose either to go the administrative route and take it through the Administrative Law Judge in the Agency, or the Agency can bring an action in a federal District Court. If it goes in-house, it's subject to the Agency's procedures, and if it goes into Federal District Court, it's subject to the Federal Rules of Civil Procedure. And there's a whole history about how these two processes have developed, which I'll get into a little bit.

Let me just outline the administrative process. If the CFTC chooses to bring a case to an ALJ, it's really the Division of Enforcement's choice. They'll make the recommendation to the Commission. The Commission has the final approval, but the Division usually determines where it's going to proceed. The hearings are conducted by ALJs, Administrative Law Judges. Since about 2001 or 2002 the CFTC has not used this route. For the last about 15 years or so, the CFTC has proceeded in its enforcement actions almost exclusively in federal court, and I'll get into that process right now.

The CFTC Division of Enforcement director, Aitan Goelman, said, a couple years ago, that he intended to bring more cases before the Administrative Law Judges (through the ALJ process), because, frankly, the procedures in federal court were more burdensome for the Agency. There's pretrial discovery in the federal court, where there is not in the Agency. And so, going through all these federal trials would be a significant burden on the Agency, which they could reduce, presumably, by going through the administrative process. But, frankly, since the SEC has been embroiled in this litigation over the constitutionality of how the ALJs are appointed and has been involved in extensive litigation on who can appoint the ALJs and have the process pass constitutional muster, the CFTC has withheld bringing any cases before the ALJs. So it's still proceeding entirely in federal court, and I think, although the Division hasn't explicitly said so, I think, until the SEC litigation settles down on the constitutionality of appointing ALJs and how they are appointed, the CFTC is not going to go that route, frankly. They have brought so few cases in the administrative process that three or four years ago, they let go of all their ALJs. So they don't have any ALJs right now, and if they wanted to bring a case before an ALJ, they would have to appoint one. And so they would directly face that question, how do we appoint an ALJ and not run into these constitutional issues? So I think that's been an impediment for them going back to the ALJ process.

Comment: If we win all these cases, the FERC ALJs are available. [LAUGHTER]

Speaker 4: So if the CFTC uses the administrative process, there is a hearing, sanctions may be imposed, and the decision may be appealed from the ALJ to the Commission and then from the Commission into the U.S. Court of Appeals. The Rules of Practice for the CFTC's administrative proceedings are modeled after the Security Exchange Commission's Rules of Practice. The Division of Enforcement will file a complaint. Then, when the complaint is filed within the Agency, an Administrative Law Judge is appointed. The respondent will have 20 days to file an answer, and then the ALJ will call the parties together and set a schedule for the Conduct of the Proceeding. In the Proceeding the defendant will have a certain number of rights. They will have the right to be represented by counsel, the right to cross examination, the right to present oral documentary evidence, submit rebuttal evidence, raise objections, and make motions. Pretrial discovery is much, much more limited than under the Federal Rules of Civil Procedures. You do not have the right to send out interrogatories, and you don't have the right to take depositions. Prior to the actual conduct of the hearing, the parties must disclose certain things to each other, such as the facts that they intend to rely on and the witnesses. They must identify experts and provide some background information about the experts. They must outline the case, but you basically don't have a right to pretrial discovery. Of course, the discussion has indicated that agency staff will have been investigating, and they'll have been conducting discovery against the respondent, but the respondent doesn't have any ability to conduct discovery either against the Agency or to subpoena a third party for depositions prior to the trial. This lack of pretrial discovery has been challenged in a number of cases. I think the last decision may be 20 or 30 years ago. It went all the way up to the Seventh Circuit. The Court of Appeals have held in several decisions that there is no constitutional due process right in an administrative hearing to pretrial discovery. So that lack of procedure has been upheld by the Court. Similarly, it has gone all the way up to the U.S. Supreme Court, that in certain administrative law procedures like this, you don't have a right to a jury trial. The seventh amendment right to a jury trial does not apply. So, as Speaker 2 was talking about, in agency adjudication, a number of the procedural protections would not apply, nor has due process ever been held to require pretrial discovery, at least in the CFTC proceedings.

As I mentioned, prior to the conduct of the actual hearing, where the witnesses are called, parties have to disclose who the witnesses are going to be and what they're going to say, and then, during the conduct of the hearing, the defense will have a right to cross examine the witnesses. There's a very broad admissibility standard for evidence. Basically, any evidence that's relevant can be admitted. The standard proof required in the CFTC administrative hearing is whether the charges or findings are supported by the weight of the evidence. The ALJ decision may be appealed to the Commission, and the Commission may review it on its own initiative.

In terms of judicial review, prior to the Dodd Frank Act, the standard for review said the Court should uphold the Commission if the findings of the Commission as to the facts is supported by the weight of the evidence. So they had the "weight of the evidence" standard. This was read by the courts to be equivalent to the "preponderance of the evidence" standard. The courts, in their decisions over the years, have basically been using more of a substantial evidence standard than actual reweighing of the evidence. If there's sufficient evidence so that the finding of the Agency is reasonable, then the Court will uphold the findings of fact. So, as mentioned earlier, if you go through the Agency administrative process, the findings of fact, under the old standard the Court isn't going to reweigh which side preponderates. It's going to ask, was the Agency reasonable in finding the conclusion that it did as to which side the evidence comes on.

Now, interestingly enough, that whole Section 6C was rewritten in Dodd Frank. Some of it is substantive, because it adopted the old price manipulation standard within 6C, but also it was just a needed cleaning up, frankly. And for some reason which I can't figure out (and I was there at the time), when we cleaned it up, the evidentiary standard no longer appeared in the Statute, and I don't recall any discussion at the time of why. My view is that probably it doesn't make a whole lot of difference that it's omitted, because it would default to the APA (Administrative Procedures Act) standard, which is a substantial evidence standard, so you'd probably get to the same place in the end--that the Court is going to review whether there's substantial evidence, and whether what the Agency concluded was reasonable.

I think Speaker 2 mentioned some of this history before, and what I'm going to say sort of dovetails with what he had mentioned previously. Initially, when the Commodity Exchange Authority, before it was the CFTC, when the CEA was created in the 30's, the only enforcement authority it had was to revoke or suspend a license. So all the early manipulation cases, basically until the 1970's, involved suspension or revocation of licenses. And also, when I'm talking about manipulation in the early days, this is under the old pricing manipulation authority of the CFTC--that it shall be illegal to manipulate or attempt to manipulate the price of any commodity or of any future contract or option thereon. In Dodd Frank the CFTC got the exact same authority that FERC has, based on the SEC 10-b authority prohibiting the use of any manipulative or deceptive device. All these old cases, these CFTC cases, were under the price manipulation authority, and they all originated with corners and squeezes on future exchanges. So if somebody was trying to do a corner or a squeeze on a commodity as a futures contract was settling, and they committed this act, the CFTC could revoke their license to trade on the Exchange, and they could appeal it to the Court of Appeals.

In all the early cases, all the case law really developed in the Court of Appeals in the 1940's and 50's, 60's, up to the 70's, based on the CFTC price manipulation authority. The CFTC got some very unfavorable decisions in the circuit courts as to what the manipulation standard was, so in 1974, when the CFTC was created for the first time, the CFTC got civil penalty authority. And federal courts got injunctive authority. So CFTC could go to federal court and get an injunction against certain behavior prehearing, or it could impose a civil penalty and do a post hearing injunction.

Well, at that point the CFTC, because it now had civil penalty authority and it didn't like the way the judicial precedent was going, started bringing cases before its Administrative Law Judges. And from the 1970's through the 1990's, we have a string of CFTC ALJ decisions. But, lo and behold, the cases that the Division brought before the CFTC, many, many of those, especially the manipulation cases, didn't win. Whereas the Division bringing the cases thought the Commission would establish a manipulation standard much more to its liking. The Commission actually developed the manipulation standard that was contrary to what the Division of Enforcement was advocating before the Commission. And in the 1980's we got the four-part test, which eventually led to the criticism that the Commission's standard for bringing manipulation cases was too high, which led to the Congress, in Dodd Frank, giving the CFTC the same anti-manipulation authority as the SEC had relating to any manipulative or deceptive device.

The Commission and its jurisprudence had adopted the four-part test for price manipulation. You had to show that the accused had the ability to impact prices, had the intent to create an artificial price, that there were artificial prices, and that those artificial prices were causes by the defendant's behavior. That was a very, very high standard. The Commission basically had one adjudicated case in 30 years where they could prove that the defendant met that standard. A lot of cases in that time got settled. Either the ALJ rejected the Division, or the Commission rejected the Division's case on manipulation. Also around the same time they had a very unfavorable string of ALJ decisions. And, as a result of that, the Division just stopped bringing cases before the Commission. It wasn't getting anywhere on the manipulation standard, and even the non-manipulation cases were getting unfavorable results. Also, frankly, the SEC was bringing cases in the Southern District of New York and there's a lot more, for lack of a better word, glamor…it's sexy to bring a case in the Southern District of New York. You're on the courthouse steps. It's big time. Saying that you're bringing a case before an ALJ doesn't have the same *cachet* as bringing a case to federal court. So I think both prestige issues and also the track record of the CFTC ALJs were in play when the CFTC turned to the federal courts. And that's where the CFTC has been.

And those cases are subject to the Federal Rules of Civil Procedure, where there is pretrial discovery, and because of the additional processes, they can potentially take longer or more resources to litigate. Frankly, if you look at the record, I don't think it would save the CFTC much time to get to go back to the administrative process, because these ALJ proceedings, as the history shows, can take a very long time.

Another topic which I can go into the questions and answers is deference. What type of deference are the courts showing to the CFTC? Does the CFTC really gets any more deference if it takes a case administratively, rather than through the federal court? There have been several recent decisions in federal court where the courts have really not shown the CFTC a whole lot of deference. Now, frankly, they don't meet the standard of ambiguity and *Chevron* deference and all that, but, basically, the CFTC, in interpreting its new anti-manipulation authority, it made the argument in a recent case that the prohibition on any manipulative or deceptive device applied if there was A) manipulation or B) deception. And manipulation, under that authority, wasn't limited to fraud-based manipulation. That was the "deceptive device" part of it, and there was a manipulative part of it, so you could have market power or manipulation without deception. And in the Northern District of Illinois, the Court rejected that argument and said, "That's not the way the statutes have been interpreted." It cited the Supreme Court case as interpreting the SEC standard, and said that that standard is a fraud standard, and that under the CFTC anti-manipulation authority it has to be fraud-based manipulation.

And now we're not just faced with the situation where we have the Natural Gas Act and the Federal Power Act--two potentially different interpretations based on process--but you've got three agencies now with potentially the same statutory language. Both the CFTC and the FERC have said, "We're going to follow the SEC, its guidance, but we're not bound by it. We're going to adapt it to our market," which raises a somewhat interesting question, because you also have the countervailing rule of statutory construction, which the judge in the case I was talking about cited. That rule says that if Congress uses the same language, it generally means the same thing. So how do you reconcile the fact that you have different markets in the exact same language? So that's an issue, I think, that has to be worked out by the courts as we go down the road. I'll be happy to answer any questions.

Question: I've got a clarifying comment. It's interesting for you to say that the CFTC's first remedy, for a long period, was just revoking licenses, because if you look at the history of civil penalties, that was true for most agencies. And the reason that Congress gave civil penalty authority to a lot of agencies is because they didn't like the nuclear weapon of license revocation. And that was true of FERC in 1986, because their civil penalty authority was limited to violations of hydroelectric licenses or licensing orders. And the notion was, you lose your license for 50 years, or maybe you get dinged with, you know, a $10,000 fine, let's give the Agency this option. But I think you probably share the observation with me that now civil penalty authority has turned into Godzilla, and it has eaten everything. It's bigger than anything agencies can do, but it started as a more modest tool. I guess that's true at the CFTC too.

Speaker 4: Right exactly.

Quetion: When you said that the CFTC doesn't currently have ALJs, how are they administratively handling some of the older issues that we're seeing around things like transaction reporting? We've seen a couple of those now where the CFTC has fined companies for not the half billion dollars, but maybe, you know, a couple hundred thousand dollars. How's that being worked through the CFTC?

Speaker 4: So there's a couple things. One is, generally, if you see an Order where they're hitting somebody with a couple hundred thousand dollar penalty, those will all be Settlement Orders. And what they will do is, they'll be doing the investigation. They will give the respondent notice and say, "Here's the enforcement action we intend to present to the Commission." The Commission will consider the defendant's response on paper, and the defendant at that time will be given an opportunity to basically settle this thing. The defendant can accept the penalty, or the CFTC files in federal court. If the defendant accepts the penalty, or there's a negotiated penalty, the action actually will be filed with the Commission. It won't be filed as a Settlement

Order in federal court. They will file it with the Commission. So these look like Commission proceedings, but there was never any proceeding. It was actually a settlement right from the beginning. The other item to mention is very small, maybe it's worth just a footnote, but there are reparations cases for customer grievances against brokers. Those can get filed before Administrative Judges. They're not ALJs, but they're Administrative Judges, and the Agency still has those, which it can use in those statutory reparation cases.

Question: So, thank you. This was very helpful, but I find the economics easier to understand. [LAUGHTER] And I'm not a lawyer, but I'm thinking back to my high school civics class, and I'm just wondering if you could explain these administrative procedures where you don't have discovery and pretrial and all that kind of stuff. I was carrying in my head the notion that you're innocent until proven guilty, and the burden of proof is on the person who's trying to demonstrate that you're guilty. But this sounds like the opposite, which is, if we think you're guilty, you have to come back and prove that you're innocent, but you don't get the to discover and do all these kinds of things. So what am I missing here? I don't remember my high school civics correctly? Or is it just because it's civil and not criminal, or what's the story here?

Speaker 4: That sentiment is echoed a lot recently in Federal agency litigation. Speaker 2 has gone through the history of this and how this developed, that agencies were given this, and the administrative process was developed shortly after the Second World War, and the administrative state was sort of at its zenith when a lot of these doctrines were developed, and you could have agency adjudications, and it's been validated by the Courts as a legitimate way to adjudicate these statutorily created rights and obligations and responsibilities, and if somebody violates it, the Agency can adjudicate it.

People have challenged a number of the restrictions on their ability to conduct discovery. The courts have said that it's not clear how much process is due. In some of these due process cases, they sort of outline generally that you get the right to present evidence. You get the right to cross examine witnesses against you and make arguments, but specifically, in the CFTC context, they ruled there is no due process right to pretrial discovery, which definitely puts people at a disadvantage. Because if you just get the witness there, admittedly you might have some indication of what they're going to say, but you've got to develop your cross examination as the person is speaking, rather than having more time to prepare. I think we're seeing, now, a second new round of challenges, especially in light of the fact that these are not small fines anymore. In the *Barclays* case, it's a half a billion dollars. These cases actually can deprive people of liberty and property.

Speaker 2: Liberty and property. I mean, that is the fundamental point the questioner just raised. Is the administrative process suitable for adjudicating a deprivation of property and liberty? Your high school civics would say, "No. I get my day in Court and I'm innocent until proven guilty." In administrative procedures that is not the case. At the FERC, you get a Show Cause Order. The Show Cause Order says you're already guilty. And you're supposed to show cause why you're not. And then you go back to the same set of commissioners again, who have already found you guilty, and you've got to start with why you're not guilty.

So the question you really raise is, (and this is not indigenous to FERC, it's across all these agencies) should they be litigating these quasi-criminal cases in anything other than a federal court, where the process is that you are presumed innocent? In federal court, the agency must make its case from scratch. You're subject to all these Federal Rules of Procedure and Civil Penalty. Because your high school civics instincts are exactly right. That is what I think most people think, and I think what the constitution requires when the government seeks to take your property and your liberty. You get that right. And so I think the question is, are these agencies ill-suited to do these adjudications? I think the answer is, yes, they are.

Speaker 3: Let me just briefly give maybe a more targeted answer to your question.

I think the questioner was focusing on something very specific, which is, if you were in an ALJ trial, forget whether it's a gas case and you're stuck with it, or you elected in a Power Act case, kudos, you get actually pretrial discovery. It may not be like in court, but I was surprised to read, and then hear Speaker 4 say that you didn't get that at the CFTC. Those tort decisions came at a period of time when the courts were maybe on the indulgent side of letting agencies carve their own way outside of on the record APA proceedings where you have most of the trappings of court litigation. And that was in a context, as Speaker 4 said, when the dollars weren't really that significant, and so maybe it didn't seem like that big a deal, but I can imagine a case where someone can very poignantly and pointedly say, "Here's why I need this stuff and I didn't get it." And there's millions of dollars at stake.I think the courts will give it a different spin, ultimately, and so I think that's perhaps a bug trapped in amber in the annals of administrative law juris prudence that would come out differently today.

General discussion.

Question 1: This panel is great, I have to say. I really enjoyed this. I like panels where equations are actually not something that could possibly be presented, but I wanted to address the question about, wouldn't it be great if we had an objective standard for manipulation, so that everyone who wanted to comply would know exactly what they had to do and not do and everyone who didn't want to comply would be on notice of what would befall them? And there's a hint in Speaker 1's comments that we should just adopt the securities standards, the SEC (Securities Exchange Commission) standard, and that is somehow objective, and it will result in that separation between the good and the bad. But that standard's been around for 80 years, and I think people might say it's as subjective as FERC. This issue came up when we were adopting Order 670 and --

Moderator: Are you talking about the fraud standard?

Questioner: Well, the standard for market manipulation. You said that there's not a coherent standard for manipulation, and you hint that securities law does provide that coherent standard. I just question whether that's true, and whether the other panelists believe that if we adopted the SEC standard, you could apply it and say, "Pass, fail, fail, pass." It would be objective and easily determined. Because this issue has come up before. It came up when FERC was issuing Order 670. At that time, it took the form of the list. The idea was that FERC should provide a list of manipulative practices, and everyone would know, just don't do anything on the list. The problem is, a manipulative mind is sometimes a creative mind. It would come up with an actual new practice that's not on the list.

Respondent 1: And that's a fair point.

Questioner: But everyone would get one free bite of the apple. So, another possibility would be, I guess, the old CFTC standard. It was a subjective standard, but it was so high that it was functionally equivalent to an objective standard that was impossible. But I guess my real question is, if we did adopt more directly the SEC standard, would it result in the objective result that you suggest? And I want not just your opinion, but the others.

Respondent 1: I think there are three parts to that. One is, the Congress said that the FERC standard should be fraud based. And so I think you should start with the idea that you have to prove fraud in manipulation cases. That's what the Congress said. Now, one can easily quibble with the notion of using the 10b-5 standard, which was a disclosure standard originally, when it was first enacted in 1934. You can say it is ill-suited for market transaction enforcement actions. That is a valid argument. I think people made that. You may have made it. I made it, for sure, when we were doing EPAct of '05. I kept saying, "The 10b-5 standard doesn't work in a transactional context in the same way an energy market as it does in the securities market." Congress did what it always does. It took something it passed before and got consensus for it. It was very much putting a square peg in a round hole, in my view, but that's what the FERC is stuck with. It's stuck with a fraud based standard.

The second thing I think would really help is distinguishing between market power cases and market manipulation cases. And, again, Craig Pirrong has written, I think, quite eloquently on this and says that market power cases should be tried as market power cases. They are a separate form of manipulation from fraud-based manipulation. I think FERC should take the step of trying to distinguish those two.

And then the third thing is, I think you can come up with a proper definition of what market power manipulation is. I know Hogan could probably do it in about two minutes, then we could have those sort of general outlines. You have to have the ability and the incentive to move price. You've got to have the ability to create an artificial price. That maybe a high hurdle. I get that. But I think there's a reason why that's a high hurdle, because that ferrets out true manipulation from true price discovery. And I think what happens in a lot of these cases is you don't get that. I think you have to show the ability to move prices in a market power case. That is the quintessential part of the equation. Then, I think, on the fraud based case you have to show fraud.

Questioner: But let me just ask you a question before you go ahead. So, would you make a distinction, in terms of the process of how you would handle it, between a market power and a market manipulation case? Or is the process identical?

Respondent 1: I think the process would be the same, actually. I think the proof would be different, and I think that one change of distinguishing between market power cases and market manipulation cases, that one change alone would go a long way to addressing the problem I have with the lack of a coherent definition of market manipulation. I can deal with the impairing of a well-functioning market if the FERC truly followed the notion that they have to prove fraud in those cases. Saying that someone's impairing a market does not mean that's fraudulent, especially when you combine that with the fact that the FERC does not hear to the "but for" test. Because if you have a legitimate business purpose, combined with whatever else, but if you can discern a legitimate business purpose, that is not fraud. Those two together, combined with not distinguishing between market power and market manipulation, I think makes it very difficult to have a coherent and rationale definition of manipulation in FERC.

Respondent 2: Actually, if you look at both the Commodities Exchange and the Securities Exchange, there are certain enumerated practices that are essentially being manipulative, other than the general manipulation standard. As Dodd Frank was going through and I was at the CFTC and it was proposed that we use the SEC standard to replace the existing CFTC standard, which is basically a market power/price manipulation standard, we faced that exact question. That is, what would this new SEC standard mean, and can we maybe refine it and come up with more clear markers for what's appropriate and not appropriate? And what we came up with at the time was that we enumerated three standards. One was disorderly trading in a settlement period without regard to the orderly execution if you were trading in the settlement period. Two was not taking the best bidder offer, if you're bidding. That was deemed inherently manipulative if you intended to do that act. And then the third was spoofing--bidding or offering without intent to execute.

Of those three, the bidding criterion is retty objective. It's clear what people can or can't do. With respect to the criterion of disorderly trading in the settlement period, there's an element of subjectivity in there. How do you know what counts as disorderly trading? What would a reasonable person do? Do we know what the person's awareness of the market is? So we couldn't get rid of all subjectivity there. And on spoofing (bidding or offering without intent to execute), as the CFTC attempted to implement that, there were a lot of howls that that was too uncertain, and what does that mean? And the CFTC issued guidelines on it. It's been challenged a couple times as unconstitutionally big. The courts have rejected those challenges.

It's a very, very difficult exercise to say what an objective manipulation standard would be. I think part of the difficulty with the SEC standard is also with this concept of recklessness--that if you make a statement or behave either "intentionally or recklessly," if you omit something or you say something without regard to the truth or falsity… The concept of recklessness really arose in that context. And now it's being applied in a trading context. So how do you trade recklessly? What's a reckless trade? I mean, I could understand making a statement with reckless disregard for whether it's true or false, but how do you do a trade and affect price recklessly? Do you owe some duty to the market to trade in a reasonable manner, generally, or whatever? So that whole concept of the intent standard in the SEC-based standard is one by virtue of which the agencies have substantially lowered their burden of proof. They don't actually have to prove that somebody intended to do X, Y, Z. They just said, "Well, you were reckless. It had this huge effect, and you should have known, and you shouldn't have done it." So I think that's a significant issue and another issue that's unresolved. I mean, the market power issue is when an otherwise legal act in the market become illegal because you have some bad intent associated with that act—if you are not trading with respect to what some legitimate view of the market price would be, but if you are trading with the intent that your trade will affect the price. If you want to move oil to a hundred, rather than believing oil is at a hundred, does that all of a sudden make the traded oil at a hundred illegal? And so, is it really just intent, what's in people's heads, or is it some objective act? I don't know how many people actually trade with the actual objective view of saying, "Well, this is what I think the price should be." Anyway, I think it's a very,

very difficult question to actually get to that state at the end that there's purely an objective standard. The CFTC tried it, and "disruptive trading practice" is the best we could come up with.

Respondent 3: A few quick points. You're right, making a list and saying, "This is what you can't do," and always catching yesterday's newspapers isn't something, I think, that makes any sense. And I assume one reason why this 10b-5 standard was enacted was because it gave more flexibility. Given that FERC lacks the original CFTC standard, which is kind of a market power standard, FERC's standard leaves it vulnerable to challenges that the defense in these cases will make. It's not fraud to exercise market power. Maybe it's a problem. But is it fraud?

That question is what Craig Pirrong's article is about. So, there's this unresolved question in FERC's statutory standard. I mean, market power is probably the single biggest problem that power markets would face, as opposed to one-off things that might just be arbitrage, or it might be a problem. You're going to see market power, and maybe FERC's statute doesn't even apply there. That's an unresolved question.

But having now brought myself to the shores of what you're really trying to get at, 10b is not abundantly clear now. It's been a long time, and the courts and litigants are still fighting about what it means. Look at the insider trading stuff these days. I mean, this is all still somewhat fluid, and the question that imposes itself in the world of FERC right now is, on the one hand the Supreme Court says 10b is a catchall, but what it catches must be fraud. Even though sometimes the boundaries of that can be a little bit murky that's kind of a clarifying thought. Or can FERC expand beyond the common-law fraud sort of thinking and say, it's impairing a well-functioning market? And we don't know the answer to that.

I happen to be taking the point of view for clients, and I believe in it, that you can't just say "impairing a well-functioning market," but you can't really expect FERC, as a regulatory enforcement agency, to not be kind of on the aggressive side as to what the definition is here. They're not going to depart from every other regulatory body in Washington, D.C., and somehow mitigate their own definition. They're going to see what they can go after. And, in part, I think that's because they want to be able to find as manipulation things they think violate the intent of the rules that may not meet what people would normally think of as fraud--something they don't like and they don't want to just say, "Stop this," and move on again. So that is one of the 64,000 dollar questions, and I'm not surprised that enforcement has teed it up this way. That's kind of what you expect the government to do, and they have a case for it. I happen to disagree with it, and we fought that battle and we're still fighting that battle, but we haven't seen the courts come to shore on it yet.

The notion that a 10b approach could be crystal clear is probably overblown, but if you had to stay rooted to fraud … I sometimes tell people, if your mother or father raised you well, you probably know if you're committing fraud in the pit of your stomach, and you know not to do it. If it's more than that, things get hard, and those are important questions.

To pick up on one final thing, to imagine that if I do a trade and I have purity of heart, or maybe to put it differently, I have no related positions that might profit from it, and you do exactly the same thing, and the trades are both profit seeking or maybe even profitable, but the difference is intent…There's arbitrariness there. You go after the same thing, and you've got a related position, you therefore assume to have blackness in your heart and you're guilty and I'm not…we're doing exactly the same thing…and that's a really complicated compliance problem. And that's the battle we've ended up not waging to finality in *Deutsche Bank*, about profitable profit-seeking trades that benefit a related position. Those should be safe harbored, but they weren't. And that also has a market power versus fraud problem associated with it, but it ends up creating (and this is the *Markowski* case in the D.C. Circuit, and the SEC case) a standard that might be saying intent was all that matters. That's kind of a thought police world that's kind of complicated to deal with if you're in business.

Respondent 1: I don't want to lose this point. It used to be a safe harbor that if your conduct was something that was contemplated in a FERC rule or an ISO tariff or an RTO tariff, that was a safe harbor. And if your conduct was contemplated by a tariff, if the activity was something that the tariff permitted, there was a presumption that it was within a lawful safe harbor, until the FERC took that away in Order 670. I think that reinstating the safe harbor would go a long way.

Look, we have these RTO and ISO tariffs that are incredibly complex. They lay out a whole range of conduct that's permissible. If you're acting permissibly within that tariff, in my view, that should be at least a presumption that you're acting lawfully and not manipulatively.

Respondent 2: Maybe I didn't state it quite articulately enough, but if I could restate the problem with the fraud based approach, what would make a trade illegal is based on the proposition that all other traders in the market are in there for price discovery purposes, and therefore it's a fraud on the market if you are trading for some other purpose. The point being that the markets really aren't that way. The fraud standard is sort of based on a legal fiction that everybody's in the market for price discovery. There are all sorts of people who are in the market because their brother told them to be in the market, or they're hedging, or they've got some automatic program. It's probably more prudent for a trader to assume that there's just a whole variety of motives. So, the whole concept of its being fraud to trade for non-price discovery reasons, you just wonder, is that a judicial construct or is that really reality?

Respondent 4: When the Commission issued Order number 670, it was in a little bit of a time crunch, becausem without a rule in place, the Commission could not pursue market manipulation or fraud in the market place to impose penalties. So we issued the rule fairly early in the process. The 10b seemed to be a very good basis, when Congress told us to follow 10b. Having a delineation of prohibited activities didn't seem to make sense, because it would just automatically create loopholes, and we all understand that the more complicated a law is, the more complicated a rule is, the more loopholes it creates. So it made sense to do it that way, and I think we thought that there was probably enough wisdom around that we could follow it.

To the point about the abuse of market power versus market manipulation and fraud, the Commission said that one does not have to have market power to manipulate that market or commit a fraud in that market. And the Commission has said that more than once. Now, one of the challenges that the enforcement staff had in the beginning was that it was surrounded by extremely well intentioned, well educated, experienced staff who worked in rate cases and who worked on the very issue of abusive market power. I mean, that's what FERC was all about from 1935 and 1938, was identifying market power and then ensuring that utilities and natural

gas companies did not abuse that power. So it was a really major, big educational challenge to work with colleagues and what is now OEMR, the Office of Electric Market Regulation, and to say, "No. Abuse of market power is different from market manipulation." And it was very, very difficult to get those two concepts straight in their heads because they were grounded in decades of working on preventing abuse of market power.
Regarding the safe harbor, Order number 670 didn't provide for a safe harbor, but during Chairman Kelliher's administration, there are at least five or six Orders where the Commission addressed allegations of market manipulation by companies and individuals who were accused of manipulating the ISO/RTO market and found that they had not, because they had followed the tariffs. So there wasn't a safe harbor, but there is precedent out there along those lines.

When the Commission issued Order number 670, the commissioners, the Chairman, thought that we could figure it out. That we could lay it out reasonably and with some wisdom. One of the turning points for me was the *Cheyenne* cases. The *Cheyenne* cases involved the manipulation of the natural gas markets, where shippers were creating phony affiliates to bid on capacity in order to capture the capacity market. It was pretty straight forward. It made sense and you could follow it. It didn't have any acronyms in it…But two of the commissioners could not see it. They didn't think it was manipulative. And it seemed like kind of a classic case, and I thought it could have been really used as a good example, and those cases went down.

But something else happened that I think was even more serious. And this is a single action. To my knowledge (and correct me if I'm wrong) this only happened once. It all evolved around the idea of notice. And notice of course is a very important concept in any area of enforcement. And what the Commission ultimately did after that was issue a Notice of Proposed Rule Making and then a final rule that made the activity at issue in the *Cheyenne* cases prohibited market manipulations. So, unlike Order number 670, that refused to have a listing of prohibited activities, the Commission, in an individual Order, made an example of a particular activity. It was like laying the groundwork for delineation of prohibited activities. And I thought it hardened the Commission to do that, because if they really wanted to follow sort of the general premise of Order number 670 and build on it (now the panelist to my left are saying that they didn't necessarily built it on it wisely), it was an anomaly. And it could really hurt the Commission for that reason. I left shortly after that, so I can't say much more about it, but, going back to this idea that the process isn't coherent, it's things like that that are bothersome, and we're still only in the first 11 years of this whole program. I mean, it's only 11 years old, although 11 years is a long time. But if you think of some of the other statutes, even the Natural Gas Act, it's taken decades, and they are still the subject of interpretation by the Courts of Appeals and even by the Supreme Court.

Question 2: Speaker 1, I think you raised the question, or you made the statement, that all of these cases should go to the courts for review. I guess the question I have for the panel is, how do we make sure that we maintain the right balance?

It would be easy if we only looked at the high-profile cases, the ones that are currently up for review. I think most of us probably agree those are cases that it absolutely makes sense for then to go to the courts. But I'm also concerned, at the same time, that that's not the universe of matters that enforcement looks at. I don't know what the margin is, but there's probably a lot more things that they look at that never go anywhere. And I am concerned that if we limit the ability of staff and the Commission too much, do we end up in a situation where more of these things become public matters? Some of these are important cases. There's half a billion dollars at stake. People's lives, in some cases, have been destroyed. I mean, they're never going to work in that industry again, so I am concerned that if we don't find that right balance point, are we putting people individually and companies still at great risk?

Respondent 1: I'll limit myself to the Power Act for purposes of answering your question. I think that the structure, as I would interpret it, where the defendant has this forum choice, can accomplish that objective, because the Commission still holds a prime role. They get to decide what to investigate, what to pursue, and what to drop. They can do that for years. And the question of whether you ultimately prove your case in an administrative forum or a court forum doesn't change your ability to prepare yourself to do that one way or the other and to find out whether you think conduct should be sanctioned and pursued. And whatever open legal questions might exist that mean that some cases succeed and some cases fail, you know, already exist. But the conduct certainly can and does get investigated. And so to me the question of having the target elect a judicial forum or an administrative forum…if you have a small case, you're probably settling it anyway, but some people may want an administrative forum. Maybe you want to fight, but it's not a huge case. Those options may be chosen occasionally, we'll see, but I think your first observation is really kind of the clarion call, when most of these cases go away or settle. So it's a self-selected group that remains self-selected by the government and by the defendant to make this a contested matter that could end up taking court or administrative resources.

Respondent 2: I agree with that. I have no problem with the Congress changing the Gas Act to give the option that's now in the Power Act. I do think, though, that the fact that you can always go to federal court is by itself a discipline on the process that makes FERC only pursue those cases that should actually end up in federal court. And those cases that should be settled and resolved will get resolved much quicker if people know they have the right to go to federal court.

I know of circumstances where the FERC and the respondent have agreed to other processes, appointing a third party administrative person, appointing a mediator. I know of at least two instances in which former ALJs were brought in to help resolve the matter without necessarily going to a full-blown trial. And so there are lots of different ways, if the case is not worthy, so to speak, of going to federal court, to resolve it, but I do think having the option of always going to federal court will provide a discipline to make sure that the smaller kind of cases don't end up there, because they won't. They'll get resolved and settled in lots of different way,s and there's lots of different procedural options that could occur. The other thing, too, is, remember, going to federal court is expensive, very expensive. As I like to say, it's great for the my family. It's not necessarily good for the defendant. And so that is also a discipline. People are not going to pursue the federal court cases for every little case. Now, you're going to have some people like Leonard Cooperman. He just got up on TV yesterday and said, "I'm innocent. The government asked me to settle for less money than I give to charity every year, and I said no. I'm going to fight it, because I believe I didn't do anything wrong." He could have gotten out of the case for what to him was pennies. He decided he wanted to fight in federal court, and I think he should have that right to do so. But the fact that he had the right to file and to fight in federal court acted as a discipline on the process. He couldn't be extorted for that money.

Question 3: You had mentioned the idea that there could be a list of certain behaviors that would be considered manipulative. On the top of that list would have to be banging the close--the idea that somebody would go in at the end of the trading day and, for whatever reason, they want the price higher or lower, and they would just buy or sell in order to move that end of day mark to benefit something that's tied to that mark. Now, thinking about it from a 10b-5 perspective and the SEC, they have prosecuted that behavior.

Would you all agree that if you had a client that came to you and said, "Hey, can I do this?" you would say, "I would suggest you not, because it would violate the SEC's market manipulation rule, assuming that they could prove your intent was in fact to move the mark and not to make money on those trades." Would you all agree?

Respondent 1: No.

Questioner: You would not? OK, why?

Respondent 1: You assumed away the problem with the question. I mean there are times when somebody is actively trading at close to cover a position, or because they have to deliver physical gas, or because they have to do who knows what. There are often times when somebody's behavior looks like they're "banging the close," when they have perfectly legitimate business reasons. Banging the close simply for the sake of banging the close is an element of fraud, because I'm not engaging in a legitimate business activity, and that is an element of fraud. On that, we are in agreement. But there's also times when those kinds of behaviors can be looked at, and there's a legitimate reason why somebody does it.

The problem we have with the FERC now is that the FERC will say it's the trading activity in and of itself that is the proof of the intent of fraud. We have a case now where there's not a single document. Not one. Not an email. Not a text. Not an IM, not a one that shows any indicia of fraud. The indicia of fraud that the FERC is alleging is the trading activity itself. So my view is, you have to look behind them and say, OK, was there a legitimate business purpose behind the trading activity? And sometimes things that can look like banging the close are perfectly lawful activity.

Questioner: I agree with you completely. I guess I'm thinking of the circumstance where we see that type of behavior, we go ahead and we start digging into the IMs and the emails, and not only do you find that there really was no legitimate behavior, but you have a hail of F-bombs around the behavior, "Ha, ha, look at me I'm manipulating the market!" So no question of intent. But --

Respondent 1: I take it with a grain of salt, any IM from any trader. Especially ones that have F-bombs, because I've never known a trader that didn't use those less than I do. But fair enough.

Questioner: But the real question here is just that that's prosecutable under a fraud based law, right?

Respondent 1: Yes, it is.

Questioner: So even though it's trading behavior that's moving the price, you're not worried about that being an example of market power. In that case it's just simply a fraudulent transaction.

Respondent 1: I agree it's not an example of market power, although it could be. It could be, depending on the circumstances of the particular activity. But I do think it creates a more clear defensible paradigm for both market participants and the government to at least start distinguishing between those two different types of behavior.

And I think everybody should be worried about what effect this entire enforcement apparatus is having on the markets, and are we seeing people leaving markets, reducing liquidity, reducing the effectiveness, reducing the efficiency of the markets, because people no longer want to take regulatory risks from an enforcement process that it seems to be difficult to defend against. That, I thought, was one of the reasons Bill and Ashley wanted to have this conversation.

Is there a way to balance the fact that we want people to stay in these markets? We want to be able to make sure they can properly assess regulatory risks and have effective compliance programs when they know what constitutes manipulation, when they know what the rules are as opposed to a game of gotcha. That actually has a market enhancing feature that in and of itself produces societal benefits. I think that should be something we should try for.

Respondent 2: Well, at CFTC, that was one of the practices that was included in the "disruptive trading practices" provision, banging the close. That's bidding, entering transactions, with intentional and reckless disregard for orderly trading during the settlement period. Yes, that was one of the disruptive trading practices added in the Commodities Exchange Act in the Dodd Frank Act, entering into transactions in the settlement period with intentional or reckless disregard for orderly trading.

Questioner: I don't know if this says anything about the SEC, but does that mean, from the FTC perspective, that the staff would not have to claim that there's fraud based manipulation with that practice? They can just go after it as a banned disruptive trading practice?

Respondent 2: That's correct.

Question 4. As an economist, when I think about manipulation and market power, first of all, having market power in and of itself is not illegal. I mean, we have structural market power tests like HHI. You know, we have the three-pivotal supplier tests in PJM, just to measure structural market power, not any exercise of market power.

And so the issue is, why can't we define the exercise of market power specifically, as we do in economic textbooks and just say, "It is an action that is meant to alter the market clearing prices for profitable purposes, over and above the competitive level." And that's usually done by withholding supply in some way, shape, or form, whether it's done physically or financially.

Let's suppose that we can define market power very clearly that way. Then what is manipulation? I don't have anything good, but if one follows the rules, the just and reasonable rates approved by the Commission, is that manipulation, just because it happens to be a poor rule or there were unintended consequences that weren't thought of? It begs the question, but I think we kind of have to start with what is the definition of market power, and then what is everything else? Is everything else manipulation at that stage?

Respondent 1: I think your definition of market power would be perfectly acceptable, except that FERC wouldn't agree with that. The FERC does not believe that it's required, in its market manipulation cases that are really market power cases, to prove artificial price, or that the price that you created was different than the competitive outcome. I would be perfectly happy in market manipulation cases that are market power cases to adopt that definition.

On the second part, the FERC itself has spoken to this question about just and reasonable versus market manipulation in the *Blumenthal* case, where it said very clearly that "just and reasonable" is not the same as market manipulation. Just and reasonable goes to the rates, terms, and conditions for a service, whereas manipulation goes to conduct. And the two are very different. So I think the *Blumenthal* case is quite relevant here. The Commission itself recognized that there was a distinction between the just and reasonable and the conduct-based manipulation cases, but for whatever reason hasn't followed that. I think that's a very good place to go back to. We've urged that in a number of cases and not gotten very far, but I think that's a very useful place to think about, and the Commission itself agreed with it at one point.

Respondent 2: It is certainly the case the Commission has said that you can have an exercise of market power that's not market manipulation. There is a category of market manipulation cases, though, that seem to be based on power over price, on what might well be called market power, and that one can try and paint as fraud, but don't seem to fit very comfortably in the normal thinking about what fraud is.

What I was trying to say earlier is that those all wear a vulnerability. They might survive it, but those on the defense side are going to attack, saying, "Where is the fraud here? This is really a market power question."

And if you ask the question, "what is manipulation?" You have fraud based activities, and then you have this frontier that we don't fully understand, and I actually think disruptive trading practices is something FERC pursues as fraud a lot. But you've got a big grey area there now. You've got market power, which may or may not be fraud. You've got what we can all sort of say, "Yeah, that looks like we can call it fraud," and then you've got another part of this universe that we haven't defined yet that may be up to the Agency and then the courts to define.

Respondent 1: Nobody is saying we should allow the exercise of market power. I want to make sure that my comments aren't suggesting that we should look the other way when people are exercising market power. The difference is that the Congress, right or wrong, said that market power cases are not civil penalty cases. Now, we may disagree with that and think that the Congress should change that, but that's the current state of the law. And FERC, up until recent, up until including the *Blumenthal* case, properly recognized that their remedy in the market power cases was to order refunds, saying somebody charged the price that they shouldn't have charged. They should have charged something different. That's not a civil penalty case. Whether it should be or not is a different question.

Question 5: I'm going to pull us away from economics now and back to one of the refuges of every lawyer, which is process. And I have a question for the panel relating to the Commission's investigative process, particularly in light of the two court decisions we've had now on *de novo* review and what the court thinks that means. The panelists, are all well familiar with the investigative process. They know all the steps and procedures that go through that. It's fairly lengthy. It's fairly elaborate. There are multiple rounds between the

Commission staff and the subject in the investigation where the Commission staff will lay out what they think happened, and why they think it was wrong. The investigated subject gets opportunities several times throughout this process to explain what they think happened and why they thought it was not wrong. You're well aware, all of this process, when the case is as complicated as cases are, often takes several years for the Commission to go through that, and then all of that happens before you would ever get to a point where you would then take the case, in the Federal Power Act context, on to District Court. And you're probably looking at several more years, if the case continues all the way through to resolution before that happens.

So with that context, in light of the *de novo* review decisions, I'm curious as to what the panel's thoughts are, if the Commission were at some point to ever look at its investigative processes.

My view is that there are at least two reasons for doing all of that process. First, to provide the investigated subject ample opportunity to understand what the staff is thinking and give them the opportunity to respond to the staff and, ultimately, to the Commission as to what their views are on the case. But also, second, to give the Commission a basis upon which it can make a reasoned decision with respect to whether there was a violation or not, and if there was, what the appropriate penalty would be, if they were to impose one at that point.

What would you say about that investigative process and how it should be changed? Should it be streamlined? How much process do you want to give up for your investigative subjects in order to expedite that current investigative process, where we have preliminary findings. We have 1b-19 letters. We have Order to Show Cause opportunities. Where would you look at in that investigative process, if you're looking at a trial *de novo* now in District Court?

Respondent 1: We've been thinking about this a lot, not just me, but a number of people, and I think it depends on where we are from FERC's perspective. Where are we in the evolution of the *de novo* question? If we get to a point where we have real sort of from-scratch new stuff coming in, then my answer is that you should have a formalized process for a non-public submission. Maybe you could collapse preliminary findings and the 1b-19 process and then issue a relatively compact Penalty Assessment Order and go ahead and begin in court.

I think you should consider not putting a number out all the time, if the subject doesn't necessarily need it. That's an area you and I talked about. It's going to be kind of complicated. How do you come up with market harm numbers? Sometimes you might have an easy time of it, but you could just say, "Here are our findings. Here's what we think this case is about. Here's what we think you should pay." That's how it was done before the Show Cause Order process. You could then not waste the Commission's resources on trying to decide something that's going to be redone. If we imagine that the *de novo* clarity does not reach that level and we don't know for sure what value resides in the Commission's Penalty Assessment Order, I think FERC's perspective would probably be that we want to keep the Show Cause Order process, that's more formal for us and it does have some elements that are good for the defense. You get a reply by enforcement. You don't necessarily get that otherwise. But I can imagine a world where you collapse the two non-public submissions into one. And, in terms of the investigative process, I don't know that you'd need to change that much. If you have true *de novo* review, the question of what sort of law exists or doesn't exist doesn't matter very much, and the case law is kind of tough, you know, in claiming that's the new process violation anyway. Maybe that will change, but it's kind of tough right now. So I would say, keep that basically the same and move to a collapsing of the informal processes into one with a Show Cause Order, or maybe eliminate the Show Cause Order process if the Court fight looks like that's really where all the action is, and that's what we would affirm.

Respondent 2: Along those lines, one of the real quandaries for the Commission with the Show Cause Process is that it still has to issue something that more than passes the "ho ho" test. I mean, they have to issue promptly, and it seems as if they have to have a sound basis for doing that. And so, I agree with Respondent 1 completely. If you could collapse several of the steps now, and actually go with the idea of a trial *de novo*, I think that would work. But, again, it's almost as if the Commission, because of the statute, has to sort of save face by saying, "We made all these findings, and we have all this evidence, and we're going to assess you a billion dollars, or a half a billion dollars, or a hundred billion dollars…" so, I mean, the Commission is in a difficult situation right now in coming up with a finding that will support an assessment, because it's just an administrative thing. They're going to court and saying, "We want to collect this money."

So I think that the Commission needs to step back and change the process, and I think it can do it. There's no reason why something that was put in place in 1978, which has only been tweaked since (the changes to the 1b process were just complications of staff practice)…They could step back and streamline it, but also face the fact that they have to make an assessment without perhaps the same evidence as they are trying to compile right now, which is still not subject to any adversarial challenge or proceeding. There was one other thing I wanted --

Respondent 1: I forgot something.

Respondent 2: OK, you go.

Respondent 1: I think the Notice of Alleged Violations process was an interesting experiment. It was kind of voiced as an experiment to begin with. I would submit that it ends up being something that now we can conclude was unnecessary, and it can tend to force the investigative staff and the Commission into a premature sort of setting of the cement around the position that there's an issue here and calling out an individual. Their career could be ruined and maybe they don't get charged in the end, so I think that's something the Commission ought to consider eliminating, which doesn't have a lot to do with *de novo* review, but it does involve the investigative process. So I didn't want to just leave it off the table.

Respondent 2: Yes, I don't find the notices informative at all. I haven't become educated. It has given me a lot of press interviews though.

Questioner: That's a different issue, but I'm kind of looking at, how do you compress the investigative process?

Respondent 2: One other thing, though. I agree with everything so far. I think the process could be streamlined. It could be made more efficient. Sending something to an ALJ doesn't necessarily mean that it's going to be speedy, either. I think all of us have experienced ALJ proceedings that have gone on. Now, in the enforcement area so far, in the gas cases, Carmen Cintron has been the ALJ presiding and she has a rather rocket docket of her own. So I think Carmen, as far as timing, has done a good job in that regard, but cases can be before an ALJ for years.

So there's no guarantee with that, but the bottom line is that I think the process needs to be streamlined, and the dichotomy between the gas and electric approach really does have to be addressed. Obviously, the best way to do that would be by a Congressional Act. I don't see how Congress is going to even pay any attention to FERC over the next couple of years. So I don't think that's going to happen. But you may remember the *Bountiful* case from the early 1980's. In the early 1980s there was this hydropower case called *Bountiful*, and when Charlie Curtis was Chairman, the Commission at the time said that municipal preference about relicensing applied. Mike Butler came in in 1981, and he said, "No, it doesn't," but the Commission had spoken, and not only had the Commission spoken, the Courts had agreed with the Commission. The Commission changed completely, did a complete flip, and also got upheld by the court. So maybe then the 2006 Statement of Administrative Policy based on the Gas Act could be revisited. And the statutes are very flexible. And if the Commission has a good explanation in interpreting the statute, maybe it could actually do that. But the dichotomy still has to be addressed, and then the convoluted approach, and, assuming that the approach that's taken, if the dichotomy is addressed, is the PAR Act approach, then that has to be addressed as well.

Question 6: I have two quick comments and a question. The HHI is easy to calculate. The hard part of the HHI calculation is defining the market from which you're going to calculate the HHI, and that is a very difficult process and very contentious in DOJ proceedings. And also, the measure of market power is the HHI divided by the elasticity of demand, and we keep forgetting that a lot of times. You can read that from the merger guidelines by looking at the discussion of alternatives. The discussion of alternatives essentially creates the elasticity of demand, which says that people can turn away, even in a very concentrated market. If they can turn away and buy another product that substitutes, the HHI is not an important measure. So, it's the HHI divided by the elasticity of demand.

I also think you can make a decent argument that the ISO tariffs actually permit the exercise of market power, but I think in some sense the prevsious commenter is right. It's permissive, and going back and saying, "I got you after the fact," is probably not fair. The idea is correcting the tariff up front.

My question is, I don't know why anybody would trade for price discovery. Maybe I don't know what price discovery is, but I don't know that I would go into a store or a car dealership and negotiate, because I wanted to discover what the price was going to be. I just want to get the best deal possible. So, what does it mean to trade for price discovery? Price discovery is a byproduct of trading?

Respondent 1: I'm just reflecting the intellectual construct as to how the Courts reach the conclusion that it's fraudulent conduct to trade for some intent other than to discover prices or for some legitimate hedging purpose, so that you get fraud whenever you trade in a manner that doesn't meet the other market participants' expectations of what a legitimate trader is. Basically, it's a circular definition that allows a lot of activity to be considered fraudulent activity.

Question 7: So, I work for a large company. I guarantee you, we never do anything wrong, but we do get investigated from time to time. And one of the things that really struck me, having gone through both CFTC and FERC investigations and any number of retail kinds of investigations (this sounds bad when I say it) is that when we have investigations, for the most part, the regulating authority comes and says, "We saw you do X on Y date, and we'd like to understand why." With FERC, there's a very different approach, which is, "Give us everything that you've done the last 18 months in a particular sub area." And the previous questioner asked what we could do to speed up the investigated process on the FERC side, and I just wonder, is that something that people have put thought into? Is there a philosophy about that? Because the other agencies come at us much more directly, and, you know, I've never had a conversation with a CFTC or somebody else where I wasn't sure after the first conversation what exactly it was that they were concerned about. Whereas, on the FERC side, we've had fairly large data requests, and we still don't know exactly what the question, or what the problem is. Is that an intentional thing, or is that just sort of a byproduct of attitude?

Respondent 1: Well, I'm going to defend FERC for a second. [LAUGHTER] There have been instances, ever since there was a group set up in enforcement called "market surveillance," as you know. We've had a number of instances where they do just what other regulators do. They call up and say, "We noticed this activity on these number of days. We'd like to learn more about it. Can you just tell us about this specific activity of these individual plans or these particular trading locations?" And I've been involved in several dozens of those kinds of calls and inquiries, and every single one gets resolved within three or four months, and in most instances, not every instance, but in most instances, they get closed out without any sort of referral to the enforcement side. I'd like to see the FERC do more of that, because they look at individual activity, and the market surveillance folks are looking at very targeted things. And I find that to be a useful process. I'd like to see that happen more at the FERC.

So, to me, that's been a useful process. I've been involved in maybe 25 to 30 of those, and I think all but two got resolved within three or four months without any further activity. Now, I've just jinxed myself completely, but I like that process, and I hope they do more of that.

Question 8: I wanted to just talk a little about the rate case I was in that Speaker referred to where he moved to strike the entire testimony of the staff witnesses as unqualified. And I just wanted to make a couple corrections. The Commission didn't actually rule on or grant the staff's interlocutory appeal on that in two days. It was actually eight days. That's very important, but more fundamentally, just to make sure that there's a little bit of record on this (and it is at 109 FERC 61108 for anyone who wants to take a look), the witness did have an MBA and quite a bit of qualifications, but the real driver was, for those of you who are not FERC practitioners, that the admissibility bar at FERC is almost non-existent, and in fact, in paragraph seven of the Order, the FERC said that in administrative proceedings before the Commission, the Commission's preference is that evidence be admitted, unless the evidence has no possible relationship to the controversy. [LAUGHTER]

Respondent 1: Do you remember what happened after that happened? What the judge did?

Questioner: I think it went to the weight.

Respondent 1: And you remember he ruled that they were giving that witness zero weight?

Question: Well again, a weight question, but just zero, OK. I think that was funny.

Question 9: Given the hour, this may need to be a topic for a future conversation. But most of this panel, as excellent as it has been, has been from the perspective of the target, or the defendant. I'd like the panel to sort of shift its perspective to that of the customer, the wholesale customer who's relying on enforcement to keep prices down to a just and reasonable level. The question is, are the standards that you've been talking about and the procedures about which you've been talking adequate today to keep rates down to a just and reasonable level, and, also, if they're adjusted to provide the procedural due process and the substantive due process for which you're looking for the targets, would they still be adequate to keep rates down to a just and reasonable level, or would FERC have its hands tied too tightly to be able to protect the consumer from market power and market manipulation?

Respondent 1: A couple of quick things. You could have prices move downward artificially, and you could have manipulation cases brought against a load serving entity or a customer, so this is a little bit of sort of like, "There, but for the grace of God…" I think the answer is ultimately that the Commission has a statutory mandate, and the Courts have a statutory mandate, about how to deal with civil liberty cases. And while there's debate from time to time, and you see some speeches about using it as an adjunct to make rates just and reasonable, the civil penalty provision is really about litigating whether there's a violation and seeing what sanction should exist, and that's, to me, really a different objective. Maybe it might go towards the same end, but someone said that "Gosh, you could be on the customer side of something, on the other side of a manipulative transaction." You don't ever get any money back because there's just disgorgement of profits. Nobody's going to make you whole necessarily, so the enforcement process isn't really built like the rest of the Commission's statutory mandate, from my perspective.

Questioner: My understanding is that as we move from very much a tariff-based protection system to a market, where the market was intended to keep rates at a just and reasonable level, the idea was that that was OK, because the Commission was going to make sure that they were well functioning markets with adequate competition, where there was not the manipulation that would harm customers. So I understand the temptation to treat these in two separate silos, but if we do, are we ignoring the Commission's other obligations, which are to protect consumers from unjust, unreasonable rates?

Respondent 2: That is actually a litigated question pending at the Commission on rehearing, so I'll just stop there.

Respondent 3: Keep in mind, again, that what we were trying to work out before about abuse of market power versus fraud, and the Commission has a very large dedicated staff that deals with market power in the electricity market. Steve Rogers is in charge of that group. The Commission has issued several orders over the last few years revising its approach to the market-based rate authority, and it goes back to the '35 Act to prevent abuse of market power. So, whether it's the old fashioned rates, or whether it's a market based rate, I think the Commission has a dedicated staff and knows its mandate to ensure that the customers, and then, ultimately, the consumers on the retail side, are protected.

Now, granted, the policing against market manipulation also goes to those markets, but, as Speaker 1 said, ironically, sometimes the consumers are benefited. Let's take the *Brian*

Hunter case, for example. In that instance, when Brian Hunter did what he did at the close in 2006, natural gas prices went down, and the people who got hurt and who ultimately sued, I think at the state level, were the natural gas producers, not the customers. The customers were happy campers in that. So I'm not saying that it takes away the commissioner's responsibility to make sure that the markets are functioning properly, but they do that in two ways, and in the first instance they do it on the electric side, because on the natural gas side it's a very different statutory scheme. They do it through the market-based review process that has been set up for several years now. People really pay a lot of attention to that. And then also to make sure that there's no fraud being perpetrated in the markets.

Respondent 2: I forgot one thing that is more directly responsive. Regardless of whether you go to court and you get a real trial, or you go to an ALJ, you go to court and you don't get a real trial, I think FERC has already succeeded in casting a long shadow about what it might think is market manipulation, and it scared the bejesus out of a lot of people. And so, you know, the notion that you're going to have anyone who reads the trade press and listens to their compliance lawyers testing the boundaries of things that they can know are wrong…I think FERC's done a lot with its existing enforcement program to deal with that, and then you've heard an argument today (and I've made it before, too) that they've actually gone too far, but the notion that they haven't used their enforcement program to try and protect consumers and keep rates just and reasonable has, I think, got a foundation problem, because I think they have.

Question 10: I wanted to follow up, Speaker 3, on something that you said earlier, where you said you would be completely happy if the court route were added to the Natural Gas Act, and that, to me, implied that you were OK keeping the ALJ out there, but given the substance of your earlier presentation, where the ALJ can't really deviate from the Commission's precedents in the decision-making process, and as you described is at a lesser…and FERC goes to Court and says, "Oh, you had the ALJ route, therefore you're not really guaranteed a right to a trial here in this court, because you turned it down when you selected the Court route instead…" Isn't it better to remove the ALJ route all together? I mean, you have to go to Congress for either one anyway, so isn't removing ALJ better?

Respondent 1: Actually, I think the Natural Gas Act provides already that the only forum that FERC can litigate civil penalty violations is in District Court. That's what's in the *Total* case, so if I was heard to say something different, I didn't mean that. Secondly, I think that if the Congress were to make that election in the Gas Act, it would have to be clear that *de novo* review means what the *Maximum* and *City Power* courts have said are real *de novo* reviews, so they couldn't use this argument that has now been rejected, as I mentioned, by an Obama administration appointee. I think it would have to be clear that that election is not a procedural Russian roulette, such that you don't really know what procedure you're going to get until you get there. But if Congress were to do that, and that predicate about what the election meant was made clear, I don't have any problem if somebody actually wants to go to an ALJ. Why they would do that is up to them. It could be a small case, and don't think they want to spend five million dollars litigating it. There's lots of reasons why. I personally wouldn't do it, for all the reason I articulated, but if that's what Congress meant, I'd have no problem.

I just think having it clear that the federal court option is always there is a cure against a lot of these issues. That has to be there in order to protect people's due process rights, and, quite frankly, I don't think protecting people's due process rights leads to market manipulation. It does not lead to higher prices. It does not lead to abuse. It protects the due process that's inherent in the Constitution. Those two are very compatible notions--that we could have an effective and vibrant enforcement process and protect people's due process rights. God, I hope they are not incompatible notions.

Question 11: To go back to your Venn diagram about market power and market power mitigation, do you think that there are clear rules now at the FERC level against the exercise of market power? Do you think they are more clear now, after the addition of 10b and the change in the market manipulation rules that preceeded that? Do you think they're more clear now, or before, and are there clear consequences?

Respondent 1: I guess I used the Venn diagram, but I don't know that I have a considered view, except that, when you add the potential to prosecute an exercise of market manipulation that perhaps wasn't mitigated by the extant RTO rules for some reason (so you've got some argument that whatever was done with the mitigation scheme was insufficient to catch an exercise in market manipulation and market power and we're casting that as fraud-based market manipulation), you've got a lot of uncertainty you didn't have before.

Questioner: No, I'm trying to distinguish just the piece of the Venn diagram that's outside of market manipulation, only the market power piece. So whatever the part of the circle is off to the left there, it's only market power. It's not market manipulation. Do you think there were clear FERC rules against the exercise of market power with clear consequences, and do you think there were more clear or less after the introduction to the 10b standard?

Respondent 1: You know, I think they're pretty clear. I'm not sure I see the 10b standard as changing that one way or the other, because you mitigate. You say, "You can't do that," and you mitigate, and there wasn't really much more FERC could do, other than prospectively change the rules if you had mitigation not kick in for some reason, right?

Questioner: But didn't the market manipulation rules change at the same time? There were some things changed about the market manipulation rules when the 10b standard was introduced, or am I missing something? I thought there was some language taken out. There was some general language about the exercise of market power removed from the market manipulation rules at the time that 10b was introduced. So, I'm just asking you, did that make things more clear or less clear? Market based rates has nothing to do with the exercise of market power inside of an RTO. That's what I'm asking about.

Respondent 3: Did we change some of the market behavior rules when Order 10b was introduced?

Respondent 4: Yeah, we did. Some of the ones that existed that grew out of the Enron…I mean, the 10b was really for the market manipulation, not abuse of market power.

Questioner: I understand. What I'm asking about is the rule that was about market power that was changed. I'm asking whether you think that made it more or less clear what the FERC rules are about market power, not market manipulation. I understand 10b is about manipulation.

Respondent 3: I think that before FERC had manipulation authority, it was pilloried for not exercising non-existent anti-manipulation authority and not exercising non-existent penalty authority, but what it tried to do was take its authority to address market power and sort of stretch it and the cover the parts of manipulation that it could. And it did that through the market behavior rules. But then, when it actually was given manipulation authority, then it seemed like the view was, "Well, we don't really have to stretch our market power legal authority into that area now." So there were some relaxation.

Respondent 4: We changed the market behavior rules at the same time we issued Order number 670 in January. So 10b really has informed the market manipulation process, not the market behavior process and not the use of market power process as associated with market based rates.

Session Three.
Counting Carbon: Pricing Greenhouse Gas Pollution in RTO Markets

A number of the ISOs are considering new market-based mechanisms to reduce carbon emissions in their footprint of the electricity sector. Proposals range from centralized procurement programs for long-term renewable energy contracts to including a carbon price in day-ahead and real-time markets. For generators, a carbon adder could "level the playing field" and address carbon pollution more efficiently than the host of federal and state subsidies for clean generation and disparate carbon policies. Environmentalists may see an RTO carbon adder as a more achievable alternative to a national carbon tax or power sector cap-and-trade program. But these proposals present many questions. Does FERC have authority to approve carbon pricing in wholesale markets if presented with a proposal filed by an RTO? Or could the Commission initiate its own rulemaking and direct RTOs to include a carbon price? What should the price be, and how should it be set? Would the market merely set a shadow price, or would the RTO collect the adder and reallocate the resulting proceeds? Would market carbon prices preempt, moot, or co-exist with state carbon and renewable energy policies? How would such a market impact or be impacted by the pricing of distributed solar generation? How would pre-existing greenhouse gas trading programs (AB32 and RGGI) react to RTO carbon pricing? What impact would such a market have on state regulation and policies?

Moderator: Good morning, everyone. Welcome back to the meeting. We've got a great panel for you this morning. This morning, we're going to talk about pricing greenhouse gas pollution in RTO markets. As you know, there has been some movement that some of the ISOs are considering new market-based mechanisms to reduce carbon emissions in the footprint of their electricity sector. The proposals are very different. The RTOs are very different, as you know. One of the main questions is whether FERC has the authority to approve carbon pricing in wholesale markets if presented with a proposal filed by an RTO. Could the Commission do it on their own, without a proposal from an RTO? And then there's the question of how it would work.

So what we want to try to do this morning is discuss the legal issues behind that, and then, practically, how it might work, recognizing the differences in different parts of the country and recognizing that all the markets are a little bit different right now. And then, obviously, we'll talk about issues of whether, legally, it can be done. Is this something that's within the purviews of the states, and how would they react to it from a practical basis?

Speaker 1.
Good morning. I want to thank the Harvard Electricity Policy Group for having me. I know that you've had wonderful high-level discussions yesterday, and I'm hoping to contribute to this carbon pricing discussion this morning. What I want to talk about is a project that was several years in the making. I had been writing, for a number of years, about Order 745, in anticipation of the Supreme Court's decision, where I and three other law professors filed an amicus brief about FERC's authority, I wanted to dive deeply into FERC's authority with respect to Order 745. And so I went all the way back to the railroads, all the way back to the Progressive Era, and studied the history of practices affecting rate jurisdiction, and then

brought that all the way forward to the present day, and it was my good fortune that the Supreme Court issued its decision just as the *Law Review* was in its final phases of production. And so I told them to stop the presses and rewrote a bit and said, "This all now confirms what I've been saying for the past two years."

And the reason I'm here is that, in that article, I also spoke about a hypothetical carbon price brought up by an ISO or RTO and how that would fare under the test that I had developed in the article.

So what I want to do this morning is two things. First, I want to use the ongoing discussions in ISO New England as a case study, if you will, for applying the theory that I developed in the article, and then give you a sense of how my theory of FERC's authority after *FERC vs EPSA*, for the most part, applies in this particular situation. And you'll see that it's not a hard and fast doctrine. Indeed, in the article itself, I talk about four different guidelines, each of which I'll introduce. And what I say, though, is that this conception of FERC's authority is grounded in 100 years of history. It is not something that is new. There is no wholesale shock to the system after *FERC vs EPSA*, but, indeed, there is really a confirmation of certain dividing lines about what FERC can and cannot do. And I'd be very happy to explore that in the questions.

My discussion is based largely on the Federal Power Act (below, the "Act"), on the Supreme Court decisions, and on appellate court decisions, but also on my historical interpretation of practices. And so we're here to talk about carbon pricing. We know that regions are considering carbon pricing. The example I'm going to use here is the ISO New England process and some of the potential proposals that are emerging there. I'm constraining the analysis in one respect at the outset, and not applying it to FERC *sua sponte* coming up with a carbon price of its own, but rather evaluating one that comes from the regions, because there are very real proposals that are under discussion right now. And the discussions right now are aimed at producing a framework document by the end of the year, and that's a faster timeline than has been taking place elsewhere. And the idea is to make the organized markets more responsive to environmental attributes and to the environmental policies that are bubbling up from the states, for example, renewable portfolio standards. And so the idea is adjusting the markets to accommodate the public policy objectives that the states have.

This will be familiar to those of you who have been following the NEPOOL discussions, but I wanted to mention this here, because one of the most important things we shouldn't lose sight of in discussions of FERC authority is the justifications that are offered by ISOs and RTOs for the various policy proposals that they have. And that actually does matter. It matters what the proffered justifications are. If the justification is that we're doing this to adjust to greenhouse gas reduction goals in the regional RPSes, that's one thing. If it's done for purposes of regional resource adequacy, you'll see that's a different thing altogether.

If you've been following this discussion, you'll see that there are various solutions emerging. The one I'm going to focus on is the idea of carbon shadow pricing in the energy market. I recognize that there are other proposals that are under consideration, one of which would apply to the capacity market. I think you'll see, as you work through my theoretical base here, that carbon pricing in the energy market is actually the most challenging, and so it's the one that I'm focusing on.

In a sample design, the ISO would incorporate carbon pricing into energy market dispatch, effectively adding a new component to LMP, and what I'm leaving off the table in this discussion is any mechanism that ISO New England might adopt to ameliorate the impacts of this on consumers--rebates through LSEs or anything like that. I'm focusing explicitly on the idea of the carbon price. And FERC has authority to approve such a proposal, and, of course, we know it stems from the core provisions of the Act, including sections 205 and 206.

And here we need to look much more carefully at what the proffered justification is for carbon pricing. Is it harmonizing with the states' policies? Is it carbon emissions reductions in the region? Is it fuel diversity, enhancing reliability with more diverse resources than the predominate resource mix in ISO New England right now? Which of these would constitute undue discrimination, as the Act defines it?

For now, what I'm going to assume (and I realize this is highly controversial) is that an energy market that does not incorporate the social cost of carbon in some fashion constitutes undue discrimination. And the reason I need to do this is to get past a threshold and talk about the rest of the test for our carbon price. This would, of course, require specific findings that existing market structures prevent renewable energy from competing.

So, back to *FERC vs EPSA*, which upholds Order 745 and is, as we know, a grant of authority to FERC to regulate "practices" "directly affecting" wholesale rates. To some, this is a momentous shift in the arc of electricity law with far-reaching implications going forward. The authority extends both to wholesale rates and to the rules and practices affecting them, as long as the practices directly affect the wholesale rate. The Supreme Court found that demand response meets the standard with room to spare, contrasting activities that have an indirect or tangential impact on wholesale markets. As I mentioned, this is a project that goes back 100 years, and what we find when we go all the way back to 1906 is judicial confirmation, a broad agency authority to regulate discriminatory practices all the way back to the Interstate Commerce Act, the forerunner of the Federal Power Act. And the original understanding was remedying discriminatory practices by individual firms involving their customers, the railroads.

After the enactment of the Federal Power Act in 1935, the relevant "practices" were those that were reflected in tariffs filed with the Commission. Today, "practices" refers to those that, as the Supreme Court said, affect markets. And so there's been that evolution of our understanding of the word "practices" over the past 100 years. And so what I've done is synthesize this evolution into guidelines for assessing individual situations.

I'm going to walk through several of the guidelines in order. The first one is that FERC regulates transactions occurring on the wholesale market. That is, it regulates market conduct and not conduct attenuated from the marketplace. I use a hypothetical with my students involving a shoe firm that wants to locate a factory in Massachusetts and needs a business license from the Commonwealth of Massachusetts, and FERC intervenes in this decision. Well, we all think that would be unwise and unwarranted, but we recognize that the reason for this is that the shoe firm is not a market participant. This is not conduct that is happening in the wholesale markets.

The second factor is regulation to address the overall wholesale market structure and functioning. And in previous cases involving capacity markets, the courts had called this the "heartland" of FERC's jurisdiction, with deference to FERC at its zenith. And this is cases that involve the quality and quantity of market inputs, for example, upholding the capacity market designs of ISO New England. This makes the justification for carbon pricing important. The ISO has to conclude that, overall, system adequacy would be challenged or imperiled without more electricity from non-fossil fuel sources. And a simple finding that it's necessary to adopt a carbon price to harmonize with the state's laws, or a finding that this would be necessary to lower emissions region-wide, would be inconsistent with this particular guideline, and, indeed, with most of the case law that's been developed over the past 100 years.

The third guideline, and I think we're all familiar with this from *EPSA*, is regulating those things on the part of the utility that are closely related to the ratea, not remote ones. And this is an economic component--that is, that there is a quantifiable and significant impact on rates. And the impact on rates, if we delve back into history, need not be immediate, but it has to be proximate in time and have some sort of causative effect. So, if you think about the Order 1000 case, regional transmission planning was held to be a practice affecting rates, even if there were intermediate steps required for an actual impact on rates. PJM engages in transmission planning. The impact on rates comes down the line when actual transmission expansion takes place. This didn't trouble the DC Circuit at all. And so the directness of a connection to rates doesn't need to be immediate, but it needs to be more direct than in the California ISO case that involved changing the board of directors of the ISO.

To me, this is the less difficult factor in my analysis. Carbon pricing, if we add a shadow cost to sellers' bids, it would completely change the dispatch stack in a region. That, to me, is a quantifiable and significant impact on wholesale rates. So I don't believe this guideline would be all that difficult to satisfy. I recognize that many commentators viewed directness as something of an amorphous concept after *FERC vs EPSA*, but, to me, it is hardly that.

Let me stop there. I understand we'll probably develop much of this in the conversation. I'm putting in a plug here for my own article. If you would all like to download and read 60 pages about this analysis at some length, please, by all means, feel free to do so. Thank you.

Question: Your premise, as I understand, seems to assume that the states have decided they want to move forward with carbon pricing. Have you addressed this issue in the context of the states that do not agree on moving forward with carbon pricing? In that case, what's the authority of the RTO independently, which I frankly am skeptical about, to offer such a thing, where it's potentially carrying out some states' policies and not others' through an integrated wholesale market? Have you addressed that issue? Are you assuming full state agreement?

Speaker 1: What I would say there is that there are other academics who focus more highly on the aspects of RTO governance than I do, and who would know more about the quality of stakeholder discussions that would be likely to prompt an ISO or RTO to move forward on this. My point is only that if an ISO or RTO were to come with a final proposal in a 205 filing to the Commission, then my analysis kicks in. You seem to be talking about what happens before then. I'm sorry, am I missing the question?

Questioner: The question is really, are you positing that the RTO has authority under 205, and in response to a state protest against this policy, that FERC can say, "Nevertheless, this is in the RTO's authority to do, we find it just and reasonablem" even though the state is saying, "This isn't my policy."

Speaker 1: I do think that my analysis grounds FERC's authority, notwithstanding the protest of an individual state about an RTO's proposal.

Question: Most of your discussions looking at things from a 205 point of view, but if you think the strongest rationale is that there's an environmental externality that's not being reflected in rates, so, therefore, they're either unduly discriminatory or not just and reasonable, then in that case there's also a 206 rationale, right?

Speaker 1: Let me stop you right there. I would be wary of couching the approval of an individual proposal (again, I'm assuming there's a proposal on the table) as capturing the environmental externality. If you think about my second factor, which is, frankly, the most difficult one, I think it has to go to overall system adequacy and reliability. I think, frankly, that the Commission has relatively limited ability to say, "We're doing this to capture environmental externalities."

Questioner: I hear you. I just don't think there's a strong basis, frankly, to say, "But for a carbon fee, there won't be sufficient electricity supply in region X or Y."

Speaker 1: We can talk about what "adequacy" and "reliability" mean. I think that if the idea is to diversify sources at the regional level and capture the attributes for reliability that wind and solar bring to the table (or do not bring to the table), I think that's how this has to be done, rather than by saying, "We are capturing environmental externalities." Just so I'm clear about what I mean by system adequacy and reliability. I understand I went by that very quickly.

Questioner: Sure. But it seems that if FERC has jurisdiction to accept something under 205 submitted by an RTO or group of states—a unanimous group of states or partial group of states--then they have authority under 206 to impose something. The burden is different. But it's not as if there's no legal authority in one area if it's present in –

Speaker 1: Right. No, no, I understand that. I'm grounding the legal authority in what the justification is. So I think it's extremely important that the carbon price not be done simply in the name of capturing environmental externalities.

Quesitoner: OK, I agree with that because then that leads to other situations like coal ash, could FERC say we need –-

Speaker 1: Exactly.

Questioenr: Great, thank you.

Question: You're making the assumption that the market is unduly discriminatory against renewables. That's a big --

Speaker 1: I'm well aware of that.

Questioner: -- a big assumption, and, in particular, it would really only even arguably, I think, apply to a capacity market, as opposed to the actual energy market.

Speaker 1: Hence my point. First, that's why I picked a carbon price in the energy market instead of a redesign of the capacity market as the case study here, because I think it is more difficult. And I agree with you that the threshold that I leaped past there is a very difficult bar to meet.

Questioner: Because FERC would be required to actually explain how, and, in the energy market, I don't know how you do that, given the marginal cost of most renewables.

Speaker 1: I've put a few examples in the paper of how that might be the case, but I understand that that justification is required at the outset, and that's partly why I'm picking the energy market and not the capacity market as the example here.

Question: I was sort of getting caught up in the same issue. Is your argument dependent on whether the carbon price is actually sufficient to attract renewables? Because in order to actually create economics that would actually bring new renewables to the market, the carbon price would have to be extremely high. Anything less than that's going to be mostly coal to gas switching and such. So am I understanding you right, that if it isn't going to bring the renewables to the market –-

Speaker 1: No, not at all.

Questioner: -- that the legal argument is different?

Speaker 1: Well, no. The article certainly doesn't phrase it that way. I think the Commission's authority depends on whether the current construct of the energy market keeps renewables out. It doesn't mean, necessarily, that the price must be set at a level that makes all renewable resources, or all low carbon resources, competitive in the energy market. It requires a finding by the Commission that these resources are currently being kept out because of the design of the energy market. And I realize I skipped over that in the analysis, but that may be one of the most challenging aspects of the entire analysis.

Question: To the previous questioner, if your premise were correct and there were no way that the Commission could make that particular finding, then we don't get to all of the other aspects of the analysis.

Comment: I get it in the capacity market design, if you have a requirement of deliverability or firmness or something like that, but in the energy market, most of the renewables have virtually no marginal cost, at least short run marginal cost, and it's dispatched first because of that.

Speaker 1: Right. I hear you.

Question: When you first laid this out, I think you made a distinction between whether it's undue discrimination on renewables versus whether it's a reliability issue, which would allow nuclear, and, say, gas. And you seem to have moved, in this discussion, to say, no, I'm just talking about renewables. Does your article think that if PJM did an analysis and said, "If we lose our nuclear units, we have an unreliable system?" that that, too, would give FERC jurisdiction? Or, without the whole renewable discussion, does that reliability card trigger jurisdiction? I thought you said it did initially, and now, in this discussion, you seem to have moved to say, no, this is just about renewable discrimination.

Speaker 1: If we could hold off on that particular aspect of it for the discussion, because I want to hear what Speaker 4 has to say.

Questioner: Did your paper address that?

Speaker 1: No. I do have something separate coming out on New, but that's a different story.

Question: Let's say you've got New England, and all the states agree. And they come in, and ISO makes the filing. And FERC approves it. Do you think, then, that somebody could take that finding, because FERC has found it's discriminatory not to have carbon in the price, and an environmental group, for example, could come in and say, "Oh, wait a minute, if it's discriminatory one place, it's discriminatory everywhere." Do you think that could happen?

Speaker 1: I think the findings are going to be specific to each market. I would certainly expect advocates for a price in other markets to look pretty heavily to what's going on in ISO New England, or in PJM, or in California.

You're invoking an issue that's a much more difficult one for me, and that is whether FERC, *sua sponte* could have a national carbon price and say that the issues are effectively decided nation-wide. I've basically avoided doing that, in the hopes that these proceedings would be specific to each ISO or RTO. I guess the best answer that I can give to your question is that I would expect that it would be a component of the discussions, but I expect that it would not be precedential, necessarily, in other ISOs or RTOs.

Speaker 2.

Thanks for having me. I'm going to talk about the current carbon pricing discussion that is ongoing at the California ISO including how it applies to the WECC and the interaction between the carbon pricing conversation at the CAISO and thoughts about regionalizing that system to include significant pieces of the Western U.S.

So, briefly, I'm going to talk about how things work today in CAISO, how carbon pricing is handled. I'm going to hopefully give you a sense that the situation after 2020 is very different than the situation today, because of recent legislation that was enacted this August by the California legislature. And I'm going to talk about a context that I think is maybe perhaps more common than the ISO New England context, where there is substantial disagreement about climate policy among the states that would like to form a regional electricity market. So we're going to have different climate policies in different states, operating within a common electricity market framework, hopefully.

Let me just say one more thing. I think that, with respect to the conversation that's occurring in California right now and in other Western states that are considering participation in a regional ISO, the metaphor that I think is most helpful is thinking about the conversations you should have and the agreements you might want to make before you get married. And, too often, people don't have the important conversations. How will we handle the finances? Do you want to have children? And they get surprised after they're married. And I think what's really productive and about the process that's occurring in the West right now is an attempt to really go through these issues and go through them in detail. It's very tempting to say that we can work this out afterwards in some sort of technical conference, but the reality is that carbon pricing has fundamental implications for the function of the market, and so, I think it's a very positive development to see this sort of work happening earlier, rather than later, and in parallel with the conversation about governance and whether we have a bicameral legislature in the regional ISO, or whether load gets votes or states get votes.

So how do we handle things today? There are basically two ways in which carbon is priced in the electricity system in California. One is under the cap and trade program, which covers in-state generators as well as specified and unspecified imported energy into California. Of course, it's important to note in this context that the ISO and California are not the same thing. However, because of California's cap and trade, the generators themselves are responsible, at least if they're sited within the borders of California, for their emissions, and accounting for imported electricity occurs at the interties, either, for specified imports, via e-Tags, or, for unspecified imports, via application of a grid average or a regional average. Actually, there are two regional average emission rates that are applied to unspecified imports.

Those of us who looked at these questions early on were worried about those unspecified imports and the role that they might play in California's compliance with cap and trade, but, partly as a consequence of the buildout of solar in the state and other renewables to comply with the RPS, the volume of unspecified imports has actually been falling quite dramatically in California over the last several years, at least given the data that we have now.

The other way that carbon carbon pricing occurs in CAISO is via the energy imbalance market (EIM). This just shows a map of the current EIM partners. I guess APS has not yet joined the market, but is in --

Comment: They're live, as of October 1.

Speaker 2: Thank you. So, this shows the EIM footprint, and the EIM allows for a carbon bid adder for energy that is intended to be transferred into California. Other EIM transfers, that is, transfers between other members of the imbalance market, don't have a bid adder. And so this is the first place where we start to see the difference in perspectives about climate policy play out in a market structure. And essentially what's going on here is that there are separate optimizations run for transfers into California and transfers between other members of the EIM footprint.

So, with respect to CAISO regionalization, the first thing to say is that it's likely to track EIM growth, right? As we think about moving to unit commitment and a fully real time market, the most likely partners, the entities that are most interested, are the Berkshire Hathaway Energy owned utilities, and APS, possibly.

It's, I guess, stating the obvious, but there are key differences between CAISO and these balancing authorities, in the current context. The resource mix is very different. I teach my students in environmental law that California builds its coal-fired power plants in Nevada and Utah, and not in California. And that has implications for the resource mix in those states. We obviously have very different perspectives about carbon.

You only need to look at a map of who is on which side of the Clean Power Plan litigation to understand that, very clearly, California's RPS targets are extremely ambitious. Today, California's load serving entities source a quarter of their energy from eligible renewable resources, and they're on track to get to 33% by 2020 and 50% by 2030. The states that would join a regional ISO with California have either lacked an RPS or have much lower targets. And, in the words of a legislative staff that I work with in California, California wants to "stay crazy" when it comes to distributed energy resources (DERs) and maintain its policies, that are quite different with respect to subsidization of DERs and continue various types of policy support for DERs. Other states in the region have different perspectives.

So this is a marriage of very different states when it comes to energy policy, albeit with significant interest in creating the marriage, especially with respect to the RPS. California is already running into a few days where solar curtailment would have been necessary but for the energy imbalance market, and that is a problem that is going to grow significantly as buildout for RPS compliance continues.

So, in this context, I think it's worth keeping in mind where California is with respect to its current carbon market and where it is going. Probably many of you have interacted with or heard about the relatively low allowance prices in the California carbon market today. Recent allowance auctions have not even come close to selling out. Nine percent or 10% of the allowances have been selling. The price is at the price floor, which is $12, and the reasons for that are really reflected in this figure. The 2020 target is the top line. The 2030 target is the lower dashed line, and those are emissions up through 2014, which is the most recent data we have. And you can see that in terms of the 2020 target, we're essentially at the target, and the move from peak emissions in 2005, 2006, 2007 to the 2020 target is relatively modest. In comparison, getting to the 2030 target is moving into a very different world. Another way to think about this, to get to the 2020 target from where we currently are requires about a million and a half tons of production per year within California's emissions footprint. Getting from 2020 to 2030 requires 15 million tons per year. So there's about a 10X difference in the magnitude of change that has to occur. And that implies much higher carbon prices within California.

There's excellent work that's been done by Severin Borenstein, Frank Wolak, James Bushnell and colleagues that looks at modeling some of these issues pre-2020, and what they find is that, given the suite of other policies that California has, there is essentially a bimodal distribution of allowance prices that occurs, where you either get very low allowance prices (that's what you get most of the time in their pre-2020 modeling, and that tracks where we are), or the market flips to very high allowance prices. And that's largely because the mid-priced abatement opportunities have been taken out of the market by other regulatory policies that essentially force those to occur at zero price to the market. Moving into the post-2020 cap and trade, I think it's fair to say, given the magnitude of change, that the probability of shifting toward that higher price goes up quite significantly, and the cost containment measures at the high end of the market become very important. This is going to dramatically increase the contrast between California and other states in a regional ISO, in terms of how the carbon price might impact bids and dispatch. It's one thing to have a $12 carbon price. It's another thing to have a $50 to $60 carbon price that's being added on to the cost of energy and other congestion, etc., in developing dispatch.

Another complicating factor in all this is that California has indicated that it has a relatively limited interest in fully linking to a regional carbon market. And that's because California's concerned that it doesn't want to be the UK vis-à-vis Poland in the European Union's emissions trading system. It doesn't want to make deep cuts in its emissions and to then share those reductions, but not, presumably, the costs of those reductions, with states that take much more modest targets in a Clean Power Plan kind of compliance scenario.

There are other legal challenges that would be very important in trying to link a California and CPP-related carbon market that have to do with the scope of the California market as it's currently designed. But this is the big issue, I think, even more than those legal questions.

So, the combination of the Clean Power Plan (assuming it survives review, which is obviously a significant assumption, but something will follow it) and the trajectory that California is on implies multiple non-zero carbon prices in a Western RTO that are very different from each other--some that look more like RGGI prices today, perhaps, five, six, maybe $10, and a California price that could be a $50 price. So in the regionalization discussion, early discussion is focused on taking the EIM carbon pricing model and trying to kind of transition it into a carbon adder that can work within a unit commitment and real time market operation framework.

There are challenges. One is an optimization issue. It may not be ideal to have essentially two optimizations running for a single market. Another (and this is a big concern for California environmental regulators) is an attribution issue. How do you actually attribute emissions within an ISO framework where you cannot compel out of state generators to report their emissions or surrender allowances, and you can't attribute power to load by looking at the interties. And there's a computational complexity question. How do you run five-minute dispatch when you're trying to run dual optimization, for example?

So, as I said, the process for developing the carbon adder is moving in parallel to discussions around governance and also, importantly, discussions around post-2020 carbon market development like the California ERISA support in the legislature, and that is also not a done deal right now. There are significant legal questions about whether the ERISA's board has sufficient legal authority to implement a cap and trade in California after 2020, and that's something that the legislature is working hard on. But all of these processes are happening in parallel.

There are three concepts that have been proposed to handle carbon pricing in a context where people don't agree about climate policy but are in a single electricity market. One is to compare emissions to a counter-factual outside the optimization. Another is to modify the market optimization, but try to keep resource attribution. That is, try to keep track of where emissions are occurring within the unit commitment market and within the real time market. The last suggestion that CAISO has made is to modify optimization, but essentially move toward regional emissions accounting and move away from specific attribution of emissions to a particular resource, and that seems to be the direction that California is moving, because the other two options face either a difficult computation problem or start to move the market away from something that looks like a single unit commitment market, and that may be challenging from the point of view of other objectives.

So we're in the middle of this in California, but I think it's fair to say that the challenges of having two footprints for carbon and electricity are very substantial, and the more that we get into the details, and the more that we move toward something that is not just a market for imbalances, but is a unit commitment market, the deeper these challenges appear to be. Imperfect solutions seem like the likely outcome, either in terms of power market complexity or uncertain attribution of greenhouse gases. And that's what I have to say. Thanks.

Question: I didn't understand, frankly, the optimization with attribution. I think you said it, but does that mean that you don't keep a single clearing price, or you just clear each resource type? I just don't understand how that would even work, unless you depart from an LMP model.

Speaker 2: So, I'll be honest and say I'm a lawyer and not an economist on this question, and I don't fully understand how that would work either. What I do understand is that undertaking that approach is computationally so intensive that it will be difficult to implement, given the current computational capacity of the ISO. And so it's something that is probably not feasible at this time, even if in theory we could design a system that would work that way.

Speaker 3.
Good morning. Thanks for inviting me to participate in this panel. This is a very topical issue, and I'm going to talk about New York. New York is boldly going where no state, perhaps except for California, has gone before, and the level of policy change in New York is accelerating. Just about just a year ago, we had the 2015 State Energy Plan. And in that plan, the state articulated the vision of a 40% reduction in greenhouse gases by 2030, 80% in 2050, with a target of 50% of generation from renewable resources and a big increase in energy efficiency. In December last year, the governor directed the PSC (Public Service Commission) to start proceedings with the initiative which we just call the Clean Energy Standard, whereby the PSC is to mandate and start proceedings and create the structure for the 50% by 2030 goal through renewable generation, with also the goal of retaining upstate nuclear facilities, and also to continue with the REV initiative, the Reforming the Energy Vision initiative, which is looking at distributed energy resources as a very major push in the energy mix. And how this fits in the context of clean energy standard is that if you have distributed resources, you get elasticity of demand, which would help balance the renewable resources, which tend to be intermittent.

So during the last couple of years, we talked about Reforming the Energy Vision, which was primarily about distributed resources. We added this Renewable Energy and the Clean Energy Standard, they go together. So we have two major public policy initiatives which came across in very short order. It's a very lofty vision. It's a very bold vision. The question is how we can make this work with our competitive electricity markets. That's a challenge.

After the PSC proceeding (and it was a very accelerated proceeding compared to the average pace of things), on August 1st, the PSC came up with the elements of the Clean Energy Standard. And the components of the Clean Energy Standard are that there are going to be RECs, renewable energy credits, for renewable resources. There are going to be ZECs, which is zero emission credits, for the nuclear resources. The RECs are bifurcated into tiers. There is a tier for the new renewable resources, which is Tier One. Tier Two is for existing resources like existing hydro. A couple of elements of this which are important to note is that out of state resources are permitted to participate in the RECs, and utility ownership and Power Purchase Agreements are not contemplated. In the context of the market, we were fearful of those two elements which, at the minimum, make resources which are receiving PPAs, for example, unresponsive to market prices and operational controlled by the ISO. So we were happy to see that the RECs and ZECs were structured the way they were, and we did not go the way of utility ownership and PPAs.

So now the question for the ISO and the question in terms of competitive electricity markets in New York is, what do these significant public policy initiatives mean to our market? And secondly, do we make the markets adapt to these initiatives, and are the initiatives outside the market, or can we internalize this public policy within our market structure, so that the market structure can help drive the objectives of the public policy initiatives?

If you look at what meeting these public policy initiatives would mean to the resource mix, the public policy initiative calls for 50% of the energy production to be from renewable sources. And if you look at the energy production by resource type in 2014 versus 2030, you will see this black segment in 2014 that is coal. There's one major coal plant in New York. That probably doesn't stay in operation in 2030. So we go 100% without coal in 2030. The green segment, which is wind, goes from three percent to 13%. You don't even see it. There's a very small sliver of solar, which is yellow, in 2014. We currently have some behind the meter solar, but in the wholesale market, we only have about 32 megawatts. So that 32 megawatts increases significantly, and gets to about 9,000 megawatts by the time it gets to 2030. That's seven percent. The brown bar is biofuels, which goes from two percent to three percent. New York has significant hydro resources in Niagara and also with Canadian imports. That hydro resource is a significant segment to get to our 50%. And that stays fairly constant over the next 15 years. And the remainder of the 50% is primarily gas and dual fuel. We require dual fuel downstate in the New York City, upper lower Hudson Valley, Long Island regions.

So this is a very significant resource change. And the question is, how do we drive this? Is this going to be off market, or could the markets drive this desired policy change as well? In terms of load shape, if you look at the load shape for New York, we are seeing the beginnings of the duck curve, if you have 9,000 megawatts of solar. This is the winter load shape, and the current load shape is in the top of the curve, and I call it the platypus curve in New York. So we are going from the platypus to the duck. And that would mean that we would have significant ramping occurrences in the morning and in the evening, and we would have to look at new market products, possibly new market products like ramping products, load following products, and different ancillary services. And it's my personal belief, and I think it's shared in the ISO, that you're better off to address these things in the energy market than in the capacity market, because it gets you better system performance in the real time, and that's where it counts in terms of integrating the renewable resources into the market.

Then, in New York, the geography's such that more than two-thirds of the demand is downstate, in New York City, Westchester, Long Island. All the renewables will be in the north and the west of New York, upstate and in the Adirondack region. If you have significant amounts of renewables which are going to be installed, the current transmission system is not adequate to transfer those to the load center. The state has two public policy transmission projects, the Western New York Public Policy Project and the AC Transmission Project, two major projects that have been identified to relieve congestion and accommodate renewables. We believe that in one scenario, there's 1,000 miles of additional transmission that needs to be built to get to the 50% by 2030. Now, there could be different scenarios, depending on what level of solar versus wind and what level of hydro comes in. But we feel that there has to be a significant transmission buildout as well. And one of the questions is that this goal has to be reached in 2030. It takes a long lead time to build transmission. So the transmission process has to be expedited as well. And, again, we will try to follow the economic, the Argentine model, to get there.

The other observation we made in terms of system implications is that, in terms of reliability, we calculate the Installed Reserve Margin, which is how much nameplate capacity we have to carry above a peak load to meet our needs. Currently, the reserve market is 17.5%. We calculated, and it's a rough estimate that we would go to at least 40 or 45% when we have renewables. Because when you have a wind farm, the effective capacity is not the nameplate capacity. It's somewhere in the region of 11% to 25%, depending on the location. With solar, it's about 30% to 40% in the summer. So when you add renewables, you cannot do a one megawatt for one megawatt replacement of existing capacity. So your nameplate capacity requirements goes up significantly. That doesn't necessarily mean that the cost of procuring that capacity goes up. We haven't done the detailed simulations or made projections on the cost impact, but the cost impact depends on three things. First of all, their intermittent capacity has an effective capacity, which is less than nameplate capacity. It also means that there would be some degree of retirements of conventional units, so another variable is the degree of retirements, and, frankly, what is the equilibrium capacity market price which would allow the needed resources to meet our reliability criteria. So it depends on volume and price. So we have to see how much renewables versus conventional capacity are required, and what is the equilibrium price to maintain these resources.

So in terms of the market implications, we are concerned about the revenue adequacy of conventional units when we have this huge influx of renewables in the system. Because when you have renewables with zero or next to zero marginal cost, they will have a depressing effect on energy prices. The gas price is already low. The capacity market can compensate, but there's a question of how much it can compensate and what kind of real time performance we would get. So we have to maintain revenue adequacy for conventional resources.

We also need to identify new products for real time performance, like ancillary services, load following or ramping, and other products which we have to identify and have stakeholder discussions about and put in place in short order. And we also have to look at capacity markets, though our preference is to address as much as possible in the energy markets, which have truer performance requirements in the real time.

Now, if the market did all of this, maintained revenue adequacy of the existing units, all that does is adjust our market for this large influx of renewables. It's almost a reaction to off market public policy actions, which is not a very desirable outcome, because if your markets have a 50% renewables requirement, you just become a 50% competitive market instead of a 100% competitive market. We don't see that as a great outcome. We want our competitive markets to encompass the whole electricity supply chain.

So, with that, we have to look at some fundamental structural change in viewpoint and adjustments to our market structure. So how can we do that? And I think Speaker 1's theoretical framework gives us a very good starting point on addressing these changes. But when we look at when the ISO started in 1999 versus where we are today and where we are going, there are some fundamental shifts. When we started in 1999, the resource mix was largely conventional generation. Now, as we proceed, we are going to have conventional generation with intermittent resources in increasing quantities, and, again, from the New York REV initiative, we'll be increasing distributed resources. And, again, it's not a New York phenomenon. Distributed resources are getting more and more economic every day, and you will see that in other regions, and it's happening. So we are going from the resource mix of primarily conventional generation to a generation mix which is wholesale generators, behind the meter generation, and a large slug of intermittent renewable resources. In terms of operating principles, when we structured the market, looking at Successful Market Design, the hallmark of that is security constrained economic dispatch, which means I will drive to an economic optimization while recognizing reliability constraints. I will not break reliability constraints while I drive to economics. So reliability and economic costs were balanced, and in most of our market design, the economics and the reliability complement each other. That's the best market design, where your economic outcome also bolsters reliability. In tomorrow's world, we have reliability costs and external environmental based externalities which now have to be balanced. So we have to look at how we can do that in our market context.

Speaker 1's framework of putting a proxy of the carbon price in the offer gives us a good starting point. So when we look at this, in terms of implementing public policy, we look at it as a spectrum of options. The spectrum goes from all the way to the right, which is a fully regulated approach--you could just subsidize and regulate and say that I'm going to give you regulated rates for 50% of my resources which are renewable. Or I could structure credits, ZEC credits or REC credits, by unit, and there's a tendency to say that pay no more than is necessary, so you can structure these RECs and ZECs by individual units. You could do PPAs. Or you could tiers of RECs, which the New York PSC has done. Or you could go more and more towards markets, which is trade these RECs, you could have credits which can be traded. You can use cap and trade, which is where the Regional Greenhouse Gas Initiative is. Or you could go to the fully internalized cost of carbon, which is where Speaker 1 is, and some other ISOs, like New England, are looking at that.

When you are on the fully regulated side of the spectrum, what you're doing is you're subsidizing the renewable resources, and the rest of the market has to accommodate that. The way I look at it, if you have 50% renewables, your 100% competitive market becomes a 50% competitive market. Because all you're doing is preserving revenue adequacy for the needed conventional resources. We would like to get to a 100% competitive market where all the resources are part of the market and the actual policy goals are being driven by the market. So, that's where we would try to go.

Just to offer some observations, the New York REC program has been in existence since 2007, I believe, '07 or '09. It's been there for a while. Many states have a PPAs for renewable resources like wind. New York has a REC payment, which is basically a handicap payment. They do an auction for how much you need, given that you get certain revenues from the market, but how much do you need for you to be viable. And the state, through NYSERDA (New York State Energy Research Development Agency), runs an auction, and the prices have been in the region of $20 to $30 per megawatt hours. So that's a handicap payment. They get it for 10 years. The new rate structure increased that to 20. And we have always said that this is compatible with our markets, because it still preserves their exposure to markets, because they depend on the market revenues, but they've asked for a handicap payment upfront. So they are still sensitive to market prices. They're sensitive to operational controls. If you're all the way on the right (pure regulation) the prices can be negative in the market and they still get a fixed rate of return, or they have a PPA, and they have no incentive to curtail production to bring the prices in line.

So that's why we think the New York REC was market compatible, but they are in the middle of the regulation-market spectrum. With the current program, they've preserved the structure. They've just made it from 10 years to 20 years, but it keeps it in the market context, so that the market helps to drive the needed policy objectives.

So where we ae going with this? We have started stakeholder discussions, and this is a concept, and it will be vetted and changed and enhanced in the stakeholder discussion, but the idea is to add a carbon price.

Now, I have to kind of refrain from addressing any jurisdictional issues, because we've got eminent lawyers in the panel, but the way we're thinking of walking this tightrope between federal and state jurisdiction is that we will create the structure where the structure involves adding a carbon price. Now, we will look to the state to set the appropriate social cost of carbon. They can set it based on the EPA number, which is $42, or they can set a different number which would help them achieve their policy goals. So we are going to propose that the state give that input as to what the carbon adder would be in the market.

The other thing has to do with the current state programs like RGGI, and even ZECs and RECs. Can they coexist with this? For example, if the EPA number of carbon is $42, and the RGGI price is $10, the carbon adder needed may be only $32. The nuclear ZECs are adjusted every year. So, if you have success with that carbon price in the market, when the ZECs are renewed, there could be smaller numbers of ZECs, and even with the RECs, going forward, you would need fewer RECs and fewer ZECs to meet the policy objectives.

The other thing is that you could do this whole thing with RGGI. That was our first proposal. You could price carbon in the Regional Greenhouse Gas Initiative, and if you make the carbon price sufficiently high, you could reach your objectives. There are two issues with that, in terms of the state. First of all, it's a multistate initiative, RGGI, so you would have to have all the states agree on the quantity of carbon allowances which are being traded in RGGI and to reduce that quantity, so that you'd get the higher price. So you need a multistate agreement on that. The other issue is that they frankly thought that the prices in RGGI which would be needed to get to the 50% would be too high.

So there's a settlement method that I'm going to just introduce, and I know that Speaker 4 will elaborate on it, which might address some of the cost concerns, in that essentially when we dispatch, we add the carbon price on top of the offer price. Suppose that there's a coal plant which offers a number, and then we add the proper carbon price. And say that coal plant is the one that is setting the clearing price. That clearing price sets the market clearing price for that period. The clean resources which have zero emissions get that clearing price. When we do in the settlement for the coal plant is we take that carbon adder out of the settlement. So that, essentially, is going back to the load. We are giving the adder to the resources that need it. And so that addresses the cost impact somewhat. And if there's a coal plant and a gas plant, and gas has a better profile of carbon per unit, and the coal plant still sets the clearing price, then the gas plant also benefits, because it has a carbon penalty, so to speak, but it has a less of a penalty than the coal plant which is setting the price. So even the conventional resources which have better efficiency, better heat rates, better emission profiles, would benefit from that.

So that's the concept. There are similar frameworks being proposed in New England. We will get comments from major players like Exelon and others, and we will adapt this concept and we will enhance it through the stakeholder process. So these are the very beginning stages of discussion. But we are looking forward to it, and we hope that we will succeed in this, because this is fundamental to our market development.

Queiton: You have clearly done a lot of analysis about the cost, and how much transmission would need to be, how many renewables and things like that would be needed. And then you sort of flipped it back to the state to say, "Tell us what the carbon price is." But did the New York ISO do any analysis itself of what the implied carbon price from doing these activities would be and how that might relate to other potential possibly lower hanging fruit within New York or regionally?

Speaker 3: Your question is what the price should be to get to the 50%?

Questioner: Yes. Did you do an analysis of what the implied carbon price would be, given the marginal cost of all those activities to reach the 2030 target?

Speaker 3: We have done some analysis. The impact is different for different types of resources, like what nuclear needs versus what wind needs versus what offshore wind needs and solar, and I've seen Speaker 4's chart. She has some numbers on that. But we had very roughly said that you need in the region whatever the EPA number is, $42 or $50, to get some movement on that.

Questioner: There's a difference between the carbon price implied by the existing policies, or, effectively, what are customers paying if we just follow the existing state policies, versus the carbon price necessary to actually achieve the goal if you do it through the market. So, were you asking about both? Because I think they're both relevant, and I think your analysis, hopefully, will show both. But they're two different things.

Speaker 3: I guess I was just thinking that the transmission and the new renewables expenses. What's the marginal cost of those activities to hit the 2030 targets, just to be able to compare it with other potential carbon reduction opportunities state-wide or regionally?

Questioner: I wanted to ask about your comments on RGGI. I do understand your first reason why using RGGI wouldn't accomplish the purpose, which is its multistate nature, although I've heard that from so many states, you almost wonder how many more we need till they all say it, and then they could all do it, but put that aside. On your second comment was that RGGI would make the prices too high, if it's an efficient market, and you actually had a RGGI trading market that reflected the goals, assuming you could get by the multistate issue and the different state goals, wouldn't it reflect a true price? Do you mean it would make the price too visible? Like it would look too high? Or what would make the RGGI price wrong?

Speaker 3: I'm not saying it's wrong. I'm just echoing what we hear from our Public Service Commission folks. They say that if you give a clearing price, which is in that carbon price, RGGI needs to be in the region of $50 for the policy goal to happen. That is a uniform clearing price. They believe that that would have too much of a, at least short-term, consumer impact. In the long term, it is probably the most efficient outcome. So they believe that if you have this tier system, which is picking and choosing and giving just exactly what you need for a resource class… for example, if nuclear needs $16 and inland wind needs $25 and offshore wind needs $50, they don't see giving everybody $50.

Quetioner: But that assumes you start with what they want and then price it into RGGI, but if you really did it through RGGI, RGGI would just go find the cheapest –-

Speaker 3: Correct, correct. And that's absolutely the long-term efficient way of doing it. But there's a concern that there's a short-term consumer cost, which is too high.

Questioner: Thank you.

Question: Who gets the adder?

Speaker 3: The clean resources certainly get a clearing price which has the adder. For the resources which emit, the adder is a penalty. The penalty gets deducted in the settlement, and the penalty is by unit. So if a unit emits a ton, versus another unit which emits half a ton or a quarter ton, the one which emits a ton gets more of a penalty than the relatively cleaner unit.

Question: Where does the money go?

Comment: I hope that the price the load pays is the price with the adder, and the price the generators receive is without the adder.

Speaker 3: It effectively goes back to the load. So if you look at the settlement, if you have a solar plant, and the price is $80, the solar plant gets $80. For a coal plant, the price was at $80, but the penalty was, say, $40. So the coal plant gets $40. So, the whole pot of money is the amount that the load has to pay. So, we adjust it in the settlement, just like today, and we have how much the generators get.

Questioner: I understand it has to be adjusted in the settlement. There are two ways I can imagine doing this. One is on average, and the other is on the margin. And if it's on the margin, it undoes the LMP story, and if it's on the average, it just reduces the uplift, the cost for other things.

Speaker 3: It's more on the average. We don't want to change the LMP. LMP is the LMP.

The LMP is the higher LMP.

Question: On slide seven, you reference that you're relying on, I think, 80% renewable imports. How do you, through your design, assure that?

Speaker 3: Assure the imports?

Questioner: Yes. To reach the goal, you need 80% of the imports to be renewable.

Speaker 3: Well, some of it is historic. We get hydro from Canada, so that's baked in, and I believe there's an assumption for the increased imports to come from hydro resources.

Questioner: So, $42 for the carbon price, but is that separate from the cost of the 1,000 megawatts of transmission that load would also have to pay for?

Speaker 3: That's correct.

Question: If we can go back to the chart on who pays what, I thought that all of the renewables are getting the clearing price.

Speaker 3: Correct.

Questioner: And all of the non-renewables are getting the settlement price, less the emission benefit.

Speaker 3: By unit.

Questioner: But your comment was that something goes back to load. I'm not clear, because load is just paying.

Speaker 3: Yes, that's what the generators are getting. Ultimately, the load has to pay.

Questioner: Right, there's no money back –-

Speaker 3: No, no, there's no money back.

Questioner: It's not like marginal or surplus or anything.

Speaker 3: That's correct.

Comment: There are different ways to do it. I have a couple slides that go through the mechanics, and that's why I went last, and I have been trying to be quiet.

Questioner: OK, if you could address that, it would be helpful.

Question: Can you go back to the pie chart again? OK, so on the left, you've got gas and dual fuel, and then on the right, do you only have dual fuel? Does all the gas go away?

Speaker 3: No, it's gas and dual fuel.

Questioner: And so, you go really from 41% gas to 28%. And then you've got some old gas that you --

Speaker 3: Yes. Correct, correct.

Questioner: So you're assuming dual fuel, but your demand curve that you're proposing doesn't have dual fuel. Do you want to talk about why?

Speaker 3: This is 2030. There's a few more demand curve circle cycles there. [LAUGHTER] I knew a demand curve question might come up.

Speaker 4.
Thanks very much. Before I start, I wanted to ask you all to make one assumption and answer one question. Assume that it is a legitimate policy to decarbonize. Everyone with me? If you assume that's true, then how many of you think the most efficient way to decarbonize is a price on carbon?

We have this very provocative topic. Congratulations to Harvard for putting it on the agenda. We have a lot of issues, and we have a lot of skepticism in the room, and I think the skepticism goes to three issues: the politics, which we really haven't talked about, but we should, and I'm sure we will. Next, the legal issue, which we've talked about some. We still have some work to do there. And then the practical side. I've sort of been nominated to talk about the practical issue, but I think keeping our eye on the goal and what we all think is the right outcome is important.

For me, personally, a source of optimism is that we didn't restructure the markets in five months. We didn't move to day two markets in five months. We're not going to get through this evolution in five months. But that doesn't mean it's not worth doing and digging in and leaning in to what some of the solutions would be.

So, with that, we've talked a little bit about how we got to where we are, and it really is sort of remarkable, in my view, that we're even having this discussion. If someone asked me seven months ago whether we would be, I would have thought they were crazy. But we do now have, at some level, each of the three eastern RTOs looking at this question, and although we talked a little bit about the Integrating Markets and Public Policy (IMAPP) initiative in New England, I think one point that's worth mentioning at the outset is that that was initiated by the states. They wrote the market sort of an invitation to a party and said, "Help us come up with solutions where we can achieve the goals through the market," as opposed to continuing to argue with each other about how the market should be adjusted to protect itself from what the states want to do that are outside of how Speaker 3 depicted the existing purpose, which is that we solve for reliability at the least cost, and we don't worry about externalities or other policies. And so in New England what's happening is that the states wrote a problem statement. They asked all comers to show up and provide solutions. Then the process, hopefully, will move into the ISO, where there'll be some evaluation of the solutions, and then there will be, at some point, if it works, consensus or partial consensus around a solution that the ISO would submit to FERC. So that's sort of an organic, bottom-up process.

What Speaker 3 described, I think, is that another way to approach it, at least at the beginning, is to have the ISO look at the solutions and the spectrum of solutions. What do they cost? Where do they get you? How do they price out, versus the status quo? And then to take that set of data to the stakeholders and have a discussion at least informed by what the ISO thinks about those questions. PJM's taking a thoughtful approach and has released a number of papers about the implications for that RTO of the different state policies and has floated a very preliminary concept idea that is circulating around a number of folks in the room and in the stakeholder process there, but they are not as far ahead as New England and New York in terms of actually looking at the math and how the RTO could, again, help achieve the policy goals as opposed to just insulate the market from them.

Those of you who are involved in New England can look at your phones and make your plans for happy hour, because you will have seen almost every slide that I'm going to walk through, because we are very engaged, as a generator in New England, in offering a response to the states with a solution that we think could work. And it is along the lines of what you have heard from the previous speakers, in terms of starting with a solution in the energy market. There are many issues to address when you start there, but given the almost unanimity of position here among the sort of learned folks in the community, we decided that that was where we were going to start the discussion, and we have laid out a model that we think could work to achieve the goal that the states have asked to achieve, given that, as we see it, reducing carbon is essentially an energy play. There are solutions that look more to a capacity solution or that look to keeping the focus on providing incentives for zero carbon resources, but we see the issue as an energy play, where you have the market able to solve for the goal by taking action on the demand side, achieving dispatch of lower emission resources versus higher emission resources, and incenting or retaining zero carbon resources. You have a suite of options available to you if you start with energy, so that's why we started there.

And so what I'd like to do is sort of flip through the slides that depict how we think this would work mechanically and then look forward to questions. But before I do that, I just want to start with a picture of what we're looking at in New York. Obviously, there are three ways to reduce carbon. You can use less energy. You can run your lower carbon plants more, or you can run your emitting plants less. And what we're depicting on this slide are the costs, putting the demand side to the side, the costs of the generation elements of the carbon reduction options on the table. So the total size of the bar reflects what the cost of each of these options is, and then the colors represent sort of how we're getting there.

So, starting from the left to the right, to the extent you run an existing nuclear plant, that would be the cheapest way to achieve carbon abatement. If you run your gas plants more than your coal plants, that's, at least for the purposes of Illinois (I should have mentioned that this is depicting only sources in Illinois) the second cheapest option. You could build new wind. You could build new utility scale solar. You could put C&I or residential distributed solar on the system. Again, these bars are representing what we're currently paying, or, in other words, the cost of these options, and then the colors represent where the value's coming from. So the options on the left are shown not having any sort of policy support, and then, moving to the right, there are both state subsidies and federal tax subsidies, showing where the difference between market and cost is coming from for those resources. The red line shows what the social cost of carbon is in the median viewpoint from the US Interagency Working Group.

The point here, of course, is that our policies are picking the things that are most expensive. They're incentivizing the things that are most expensive. So what we have been articulating in the New England process is an energy market solution, and what I'll walk through is sort of one way that identifying that price and working it through the market could work mechanically. There are other ways to do it. But because what we're talking about here is an invitation from the states to have the market achieve the goal, the states would work together to translate their goals into a set of year by year carbon emission goals for the footprint, and then there would be a formula to determine the carbon price necessary to achieve that goal.

Now, all the regions are different, right? They have different fleets, and they have different carbon reduction opportunities. It just so happens in New England that they have a relatively low-carbon fleet, and that, as a practical matter, the only way for them to achieve the carbon goals that they have on the books right now is to add new clean resources. That is not necessarily the case for other RTOs. But in New England, if you assume that that's true, and that the cheapest new clean resources are at that $80 a ton figure, then that's what the cost of reducing carbon is going to be in New England.

Now, who thinks we can put $80 a ton into the market price tomorrow and have anyone at the ISO or in state government keep their jobs? That's probably not going to happen. So that's why this slide is talking about ways to phase in a carbon price to achieve the goals that the states have set. But if you just step back a second, you think, well, if the US social cost of carbon is $42, but it costs $80 a ton to reduce carbon in New England, then what's wrong? What's wrong with the social cost of carbon? I don't think there is anything wrong with the social cost of carbon. It just means that what New England should be doing is building a wind farm in MISO, but that's not what they want to do. They want to reduce carbon in their footprint. That's what their state laws tell them to do, and so, for them, it's more expensive, and that makes this process a little bit more complicated. And, as a practical matter, I think it means that you're going to have a situation where you are both reflecting carbon in the energy market, and you are continuing with existing state policies to make up the amount of dollars that are needed to incent new clean resources. I don't think that's a flaw of the model, and Speaker 1, you got a question that was somewhat about this. I think it is true in New England. I don't think, as I said, it's true in PJM. I don't think you need anywhere near that kind of carbon price to incent carbon reductions in a footprint that already has a lot of opportunities for coal to gas re-dispatch, and for efficiency and nuclear retention, etc.--the things that are on the left side of the chart I just showed you that are cheaper.

But, in any event, in New England, we would need to settle on some sort of starting price, and if the states agreed, and the ISO thought it was sensible to start at the US Interagency Working Group social cost of carbon, that's $42 a short ton in 2017. The ISO tariff could have a process for comparing actual emissions year to year, versus the goals that were set when the tariff was written. And if it made sense, there could be some agreed-upon escalation schedule, and then that would continue until the states' goals are met, and at the same time, what would happen is, of course, the cost of these existing state programs would go down to the extent that the price that the clean resources are receiving in the market goes up.

It is important, though, to recognize that we're not talking about a situation where we're going to have escalating carbon prices indefinitely, even though the US social cost of carbon continues to escalate with inflation. When we set up a model where we're tying the price to the goal, once the goal is met, of course, you're not going to see the price go up anymore, and, indeed, you're going to see it go down as the sort of pass-through rate into energy prices reflects a cleaner fleet. To the extent you have zero carbon resources on the margin, you're not going to see a carbon adder in the LMP, because that resource does not bear the cost of the carbon adder. So, in any event, the process, as we envisioned it, and what we've laid out in New England, is that that carbon adder is added by a unit to its bid, based on its emission rate. The LMP is set based on the stacking of units, with a carbon adder reflected in each unit's bid. And then, although the clean resources will see that higher LMP, the emitting resources will see the LMP minus the adder.

That bucket of dollars created by the adder could be used for any number of purposes. There were a number of questions before about where does that go. And there would be a number of parties that would say that money should go back to the LSEs in the footprint to use to mitigate the higher wholesale market price. There are a number of parties who would say, no, that money should go to some other purpose, low income, funding some other state program ala what's done with RGGI, right? I mean, not all the RGGI dollars go back to customers. Some of them go for other purposes. You might see environmental groups say, "I don't really want those dollars going back to customers, because I want them to see the higher price as an incentive for them to reduce demand, and that's the sort of efficiency gain I want to see out of this model." So there could be a number of ways to do it. I don't think it's relevant, personally, to the legal analysis. I think that's largely a political question. But it does, much like RGGI, create this benefit of having some proceeds from this program that can be used for, as I say, customer rate mitigation or for other purposes.

I want to skip over that and just go right to this slide, because I think it gets at, again, some of the questions that we just heard. On the left, we're depicting the status quo for a number of resources: wind, nuclear, a gas CCGT, and a CT, and then an oil CT. So, just working left to right, right now, for a wind unit, there is an out of market support payment through a REC that that resource receives. So if you look at the chart on the bottom (and in this example we have a CT on the margin setting the price at $40), the wind unit is going to get paid that $40. It's getting a REC credit payment for $35, and so its total gross margin, this is just energy, is $75. A nuclear unit, again, gets paid the $40 clearing price. It is not a payment like the renewables get, for the clean attribute. It has a fuel cost, unlike the wind unit, so it's seeing a real price of $30. The CC is getting, again, the clearing price. It has a $30 fuel cost, and so, its gross margin is $10, and then the unit on the margin is flat. And the oil CT does not run, because it's more expensive.

This next comparison reflects an assumption of a $42 carbon prices that has now been reflected into the dispatch. The gas CT price goes up, in line with its carbon intensity, by $21 per mWh. So that sets the price at $61. The wind unit is getting that price through the market. Its needed REC credit is reduced by that same $21, so its REC payment goes down to $14. It's flat at $75, relative to what it was in the status quo. The nuclear unit sees the higher market price and doesn't have a carbon adder. It's seeing a higher gross margin as a result of this policy. But the next line reflects an important point that Speaker 3 made, which is that the more efficient gas unit is seeing the higher LMP, but it's more efficient, so it has a reduced carbon adder of $16 versus the $21, and so, after you factor in its fuel cost, it is better off. It's an incentive for that unit to stay in the market, because it's lower emitting than other resources. It's making $15 rather than $10 in the status quo. And then, the gas CT is flat.

So the picture that we're trying to paint here is that the market is picking the cheapest way to get to the goal. It's incenting the resources that do so most cheaply, and it's reducing the cost of the programs, while not eliminating them. At a $42 level in New England, it's reducing the cost of the programs that the states have to bring in new, clean resources.

So what we're showing here on the last slide is how we try to add this all up in terms of what it means for consumers. Because, clearly, we wouldn't be doing this if we didn't think it had some net benefit. So what we're showing here is a 2030 illustrative retail rate impact. This is an average across all the states in New England of the impact of having a $42 a ton carbon price. Under this model, of course, we haven't escalated the carbon price, because we're still at $42 even though we're out into 2030, but it's just illustrative. It's just an example of how this could work. The $42 translates into $21 per megawatt hour in the energy price. So that shows in the green bar at the left, at the higher wholesale market price versus the status quo. If you assume you don't have any carbon reduction goals, and everything is going to stay the same, and no prices are ever going to go up, whether through the wholesale rate or the retail rate, then that's now what we're comparing this to. We're comparing this to what the outcome would be if we were to continue with the existing state policies and not reflect carbon in the wholesale market. So we do see a higher wholesale market price.

But what do we get for that? Well, one of the things we get for that is that bucket of dollars we talked about. Using the dollars on this chart, that comes out to about seven dollars a megawatt hour in terms of money that is available that the RTO is holding on to for a rebate to retail customers to mitigate the higher wholesale price. So, if you were to take that pathway and reflect that as a benefit to consumers, you would deduct seven dollars from the $21.

The next bucket is looking at how much existing state programs are going to become cheaper if new renewables are receiving compensation through the market as opposed to through a REC program. That next seven dollars represents the amount by which state programs go down in cost as a result of the market covering a share of the new renewable costs. So, that gets you to about a seven dollar per megawatt hour higher market price than you would otherwise have if you didn't use the market for this purpose.

And then the question is, are there other things that you gain by doing this? And so what we're depicting next is the avoided cost of having to add new zero carbon resources to the market to replace nuclear plants that retire. And this avoided cost would be lower if you used the cost that is getting paid in New York. It would show up as a lot less than this. But if what you show is the cost of new renewables, it's going to show up at about an eight dollar per megawatt hour benefit.

I'm not a mathematician, but to me, that brings the price pretty much down to even, or maybe a little bit better, in terms of what customers are actually seeing as a result of this pathway, as opposed to the existing pathway.

The next two red bars would bring the price even lower, and it would show, in fact, a net rate benefit to consumers of taking this path. But the next two bars assume a state of facts that are not in evidence today, and I'm not sure they ever will be. But there are a number of folks who would argue that the existing state policies, including both RECs and, to the extent there are programs that would fold nuclear into zero carbon programs, that those programs should for some reason be mitigated either in the energy market or the capacity market. In reality, I think that's one of the things that brought the states to the table in New England, because they saw continuing arguments over that question. And so what we're representing here is the avoided cost of what that would mean to consumers if that would be where the RTO or FERC were to take the policy. As I said, that is not the law today, and I don't see it happening, but that is a potential benefit to consumers from avoiding the risk that that were to occur.

I'm happy to take questions. I would like to, if I could, just answer one of the questions from earlier while I have the mic. I think it's a legitimate question to ask, if one RTO were to do this, then does that mean that FERC would, by definition, have to either expect or require other RTOs to do it? And while I think it's a good question, I think, among the questions we have, it's probably one of the easier ones for FERC to deal with, because the zone of reasonableness under the precedent is so broad. I mean "just and reasonable" is not sort of one thing, it's a zone of things. And it's a lot easier to say that including the cost of carbon is reasonable than it is to say that not including the cost of carbon is unreasonable. I think that, for better or for worse, that is how the precedent folds out, that when someone is proving something is just and reasonable, that burden is easier than when the burden is on someone challenging the rate to say that the existing rate is not just and reasonable. So I think those are sort of two things that FERC, I would expect, would point to to distinguish why they're OK to accept it in one region and that they're not being inconsistent by not requiring it in other regions.

I think the legal issue only really matters to Max Minzner (FERC General Counsel), to Bob Solomon (FERC Solicitor), and to the great Americans on the 11th floor (the FERC Commissioners). And so, what is their legal analysis of the risk that they take by doing this, and what is the risk they take by not doing this? And while we would all hope to influence what those five people at the moment think, it's going to be their call.

Question: How do you treat the potential for imports in this? What's your assumption?

Speaker 4: I might sort of rely on Speaker 3 a little bit to help with this, but I think the thinking is that this is an easier model for dealing with imports than, for example, the RGGI model, where they've had such challenges with leakage. I know California has an approach for dealing with imports when it comes to their cap and trade program, but with this program, I think, once you have an RTO tariff that sets what the carbon price is, then, if you have imported megawatts, you tag them with that same cost. I think it's less complicated than the alternative, but Speaker 3, you can speak to that.

Speaker 3: One simple way would be to just say that there's an import coming from the next region, put in whatever generation is on the margin, and put an average cost of on the penalty. You could base it on the generation on the margin, or even on the whole generation mix in the other ISO. You have to come up with some kind of assumption on the unit specific emission rate of the neighbor. So, simple as that, if you assume that the neighboring ISO is exporting from a gas turbine, and you pick a representative gas turbine and put whatever penalty a gas turbine would get, and put that in there for all the imports.

Question: It's one thing for an RTO to be helping to effectuate a set of state policies, because we do that today. But it's a different matter for the RTO, the RTO board, to be be implementing something it decides is a good policy and a good price, and some of the states say, "That's not my policy, so I don't want you to effectuate that." So help me through that conundrum, which we would have in PJM, quite frankly, both from a legal and practical point of view. It's a "who decides" issue.

Speaker 4: I fully appreciate that. I mean, obviously, New York has one state to deal with. New England has six, four of which have the same carbon goal. PJM has 14 jurisdictions, and so we all appreciate that it's going to look a little different in PJM, which is why I assume that PJM's taking a little bit of a slower road here. It may mean that you would look to a different structure. You might not have exactly the structure that we're laying out here. It may mean that your burden is a little bit higher when you write your pleading to explain why there's a benefit to other states, even those that are filing a protest against you. But I don't think anybody expects that if you had 14 jurisdictions saying, "PJM, you should stay out of this entirely," that PJM would be running to FERC, or to the Board first, and then to FERC, to file something.

So the premise here is that you have some amount of states that have a desire for you to help them achieve their goals, and that you can make a case that there's some benefit to the rest of the footprint from doing so, or you move to a different model, where you're just solving for those states' goals. I think there's a bunch of different permutations. So, keep working on it.

Speaker 1: If I could jump in here for a second. I now understand what it was that you were asking me earlier. I'm just assessing the legality of what you might think of as the purest case. That is, if all of the stakeholders in an RTO agree to bring a 205 filing to FERC. And I would agree completely with Speaker 4. I'm not talking about a scenario where FERC is going to impose a price designed along the lines that Speaker 4 has discussed over the objections of all of the stakeholders in the region. That's not my intent. I just want to be clear about that.

Question: One of the things that I'm always interested in hearing about from the presentations are the assumptions regarding the social cost of carbon. Because when I go back and look at the intergovernmental panel study on the social cost of carbon, they make it very clear that there's a pretty wide range, anywhere from like $11 to $120 per mWh. And they're also very clear that there's no consensus as to what the appropriate price is, and then go on to say that, for purposes of capturing the uncertainties involved in regulatory impact analysis, we emphasize the importance and value of considering the full range. I mean, I don't know that that necessarily changes your conclusions, but, depending on where that number's going to be, you get some pretty different results. Maybe you can talk a little bit about that.

Speaker 4: It's true that there are a number of numbers in the US Interagency Working Group document, and I think the variety largely depends on the discount rate, because it's a forward projection of the impacts on human beings of a ton of carbon being emitted into the atmosphere—impacts on crop yields, health effects, things like that. I think it's important to also acknowledge that the social cost of carbon document itself was intended to be used by agencies in doing rulemakings, where they're assessing the impact of things that they might be doing and what the cost of that, in terms of carbon emissions, might be. So, admittedly, this is a somewhat different purpose to put the social cost of carbon to. And there are any number of people who will say that it's either wildly too high, even if you just take the middle of the road number. (That is what we did, by the way. We took the sort of central discount rate that the US Interagency Working Group had in there. We just picked that one, because it's in the middle.) But there are any number of folks who think that is wildly too high. And then, there are a number of studies I've seen. There's one out of California that was alleging it's way too low, because it doesn't take into account sort of the impact on the economy, globally, of these other impacts on humans. So it doesn't sort of factor in the lower GDP as a result, or slower growth as a result.

So I have no idea what the right number is, and for New England, as I said, I'm not sure it matters that much, because the cost of bringing in new resources is well in excess of that central tendency anyway. It would be some sort of settled place to start, if they chose to start there. They could also choose to start way lower than that, and, indeed, if you can achieve significant carbon reductions with a $20 cost of carbon, then why would you get anywhere near the social cost of carbon? You would use the number that you thought could achieve your goals.

Interestingly, we're talking about this in terms of state policies, because that's sort of where we sit in the landscape here. Fast forward the tape two years, if we have a Clean Power Plan that's in effect and maybe has been strengthened by the next administration, even just using the values that are in the current plan that's on review now, EPA estimates that that translates roughly into a $17 per ton cost of carbon. So there could be any number of numbers that would become available on a federal level, other than this one, assuming future events unfold as the polls suggest they might, sitting here today. But this is one number, and it has its critics. It just has the virtue of being something that at least the US federal government has put out there.

General discussion.

Question 1: I actually see the possibility of a carbon adder going into New York. It's a single state. If the state supports it, I see it being less controversial. I frankly think there's no way in hell in New England. It's called Vermont. I think in PJM, it gets even uglier.

So my question to you is, I disagree that FERC has the jurisdiction or maybe the political wall to protect them, to approve this where there wasn't unanimity in a multistate RTO. However, I think it is clear that they have jurisdiction if it is a reliability issue. And that was my question earlier, and we kind of skirted it. And so, the question to you is, if we get it in on the basis of reliability, do we still continue to use this kind of schematic approach? Does it still hold up? Is it a different approach when you put it in front of FERC as a reliability issue, as opposed to a carbon adder issue?

And I have to add, my one concern on behalf of consumers is that we agree that nuclear is a valuable resource, and that it should be compensated, but there's a lot of heartburn in all of this. Besides the transition costs, the nuclear plants made a lot of money when coal was on the margin and there were higher gas prices, and we have some angst on behalf of our customers. We don't want to overpay for a resource that got paid very well, and shareholders did very well.

So I've kind of put two dead things in front of you. One is the reliability question, and how you address that, and two is, how do you address the consumer concern that we've paid for this over and over, and what's in it for us?

Respondent 1: You want me to start? So, on the legal question, I was interested to read Speaker 1's article and hear him today, because I don't necessarily think about it as undue discrimination based in the legal analysis. I think of it as taking one of two pathways. Either there's a case made that "just and reasonable" can evolve with the times, and it may be that at one point we define "just and reasonable" as entirely based on cost and reliability, but in today's day and age, we can, as an agency, decide that we can legitimately include the cost of pollution, even more so if you're talking about an RTO type of situation, where you have the language in 202, which talks about an abundant supply of energy and conserving natural resources as a reason to form an RTO. So that's pathway one. One of the legitimate costs in the cost buildup is the cost of pollution.

Pathway two is the one you're asking about, which is, now we're going to say that there is an impact of the environmental effects of pollution on either rates or reliability, and we decide whether it's because the cost of putting carbon in the market is cheaper than the alternative (that would be the cost basis), or whether, for reliability purposes, we're going to anticipate system effects as a result of either climate change or as a result of any number of impacts of not addressing the carbon pollution.

Questioner: Could I challenge you to take the carbon out, because gas is being built because it's cheap? It's not being built for carbon, and that, I think, is what's driving the reliability concerns. So, it's not a carbon concern. It's not a renewable concern. It's a price concern that we are relying on —

Respondent 1: So, you're asking, take carbon out, assume that FERC makes the change based on some issue that it sees with respect to reliability that is solved by what? By nuclear, or by carbon-free resources generally? I think it's a different answer depending on what you're assuming. If it's nuclear, then it's probably also something that's solvable by a coal plant, in which case it's not a carbon-based change to the markets. It's, as you put it, a reliability-based change, and the analysis in Speaker 1's article wouldn't come into play at all. So it may be a benefit to nuclear, but it wouldn't be based on carbon.

I think that's my answer to your question. I mean, I was answering a different question, a way to make a change based on carbon as a result of the reliability impacts of not doing so. But if that's the path you're on, then I don't think Speaker 1's analysis comes into play at all. You wouldn't solve it by putting a carbon price as a solution. You'd solve it by monetizing what the value of having that fixed fuel asset on the system is, and then finding a way to compensate for it.

Questioner: That was part B of my question, which is, if you take the climate out…And this is quite frankly, what's happening in PJM, right? They realized that they can't do a carbon adder with 14 states, so they are doing a fuel reliability assessment. And I predict that, lo and behold, we're going to come out and have a problem, because how else do you get to the fact that they want to keep nuclear units on the system? So this is not a hypothetical.

Respondent 1: I'm not so sure you should assume that. I'd take a lot of money on the other side of that bet.

Questioner: I don't know, but my question is, can you, is there precedent to say you canstart selecting fuel types, regardless of whether you call the reason carbon or something else? To get that resource diversity, does FERC have the authority to drive to different investment in generation types?

Respondent 1: There's more educated people on that than me. I personally don't see diversity *qua* diversity as something FERC would ever regulate to. I think you have to define the attribute that's missing. PJM did something like this with the capacity performance initiative, and then you price that. So, whether you're pricing carbon, or you're pricing resiliency, or you're pricing fuel security, whatever it is, I don't think of it as diversity. That may be the outcome of your policy change, but that's how I see it.

Comment: I absolutely want to jump in on that last point and make a point about fuel diversity versus diverse attributes that fuel sources bring to the table. And those are two very different things, in my analysis.

I start from the basic premise that a conception of reliability based on the diverse attributes that different fuel sources bring to the table could be a more solid foundation for adopting a carbon pricing remedy than simply saying, "We're internalizing externalities." But I don't think that that means we need more renewables. Instead, I think it means we need the attributes, such as the ability to run when gas pipelines are constrained, that these resources actually bring to the table. And that might mean a different analysis for nuclear and for renewables, just simply based on what they do, but my overall point is that the reliability attributes are what stand in here for internalizing the environmental externalities that a carbon price does. And I want to be very clear about that, that that's sort of a foundation on which everything else I have to talk about is built, and if we don't agree about that, I have nothing else to talk about. [LAUGHTER]

Question 2: Speaker 4 had started out with her little survey, and there seems to be general agreement that if you put a price on carbon, you'd get an efficient result, and then, Speaker 4, you made the connection then that that would be a reasonable thing to do. And it strikes me, as we look at cap and trade programs, that they haven't been very effective in large part because there've been so many interventions to mandate renewables and subsidize renewables that the price hasn't really mattered. And, Speaker 3, when you had showed that spectrum of things you could do in New York, it was concerning that we might end up with ISOs putting a price on carbon and states continuing to do these massive interventions of 50% renewable mandates, and so forth. So, my question is, to make for a reasonable result with this price being put on by ISOs, not only do you have to get the states to agree to this, do you also have to get the states to agree to back down and stop the other interventions that would make the result maybe less reasonable?

Speaker 3: I can start because I actually suggested that there would be some period, at least in New England, where you could have both a carbon price and a continuation of state policies until the price gets to a point, either through the cleaning of the fleet or a reduced renewable integration cost, that it becomes more palatable to consumers. So it's a fair question.

The way I think about that is that, at a minimum, putting the price on carbon is going to bring down the cost of the state programs. I mean, if you have a state that just says, "I'm going to ignore the fact that there's a shift in the policy and that I should expect some amount of decarbonization or carbon policy going forward, and I'm going to assign a fixed price, a long term contract at a price that doesn't adjust," then what I just said is not true, right? That is not going to get cheaper, because that contract is going to stay in effect. But if you have programs like renewable credits or zero emission credits, that adjust, then you are going to bring down the cost of those state programs. And if the price is adequate, it's going to bring them down to zero, right? I mean by definition, the price is set at the social cost of carbon, and the ZEC credit is paid based on the social cost of carbon. Then it's just math.

If you're asking whether the federal government should tell the states, "You should never be allowed to do something that's more expensive than necessary to achieve some goal," that states should never have a policy where, just for political reasons, they want to build something that that like more than what a cheaper option would be, that's not a question for me. I mean, is that something that federal regulators would ever do? I don't think so, but it is possible, I suppose.

I think the easier question is, to the extent a state wants to overpay, then if this program is based on a carbon goal, and the carbon price can achieve the carbon goal, and the state wants to do something else that's not justified by carbon, I sort of see that as being an easier question to answer. But you're putting your finger on one of the things that's going to have to be part of this analysis, which is, if everybody's giving something, what are the states giving in this process? And that remains to be seen.

Questioner: Speaker 2, if you could comment, because your example had a lot of interventions where you could get, in the West, these two very divergent carbon prices. And it seems like that's a fairly inefficient, maybe, even, you could argue, unreasonable, kind of outcome.

Respondent 2: Your description of the facts is very consistent with how the California carbon market has performed. The one piece that I would add is that the caps were set based on what turned out to be unrealistic assumptions about load growth. So we have a combination of very aggressive policies that are not carbon related but have impacts in the carbon market, and less load than we expected.

And is California going to stop doing that? I think the function of the carbon market, politically, has to be something that we think about, right? In this room, we think about carbon markets as a way to price an externality and reduce the externality in the most cost-effective manner. I think that, when you talk to state legislators about carbon markets, they often want to know how much money they're going to get to spend on various programs. And that can be a primary driver, more than thinking about the cost-effectiveness of an overall energy agenda. And there is, paired with that, a concern about how high the price is, and the optics of that, especially in California, where that price is directly translated into a gasoline price as well. In California, the coverage is also of liquid fuels. So you have the Western States Petroleum Association pushing its members to put a sticker on the gas pumps in California that says how much of the gas price is driven by California climate policies. And so the advantage of hiding some of the mitigation, maybe in an RPS, is that you produce a low carbon price, you hit your target, and the costs are still there, and you're probably paying much more than you might otherwise have, had you allowed the carbon market to work. But the political costs of that are very different.

Respondent 3: The carbon price, we believe, is the more efficient way to do it, but it can coexist with things like RGGI, RECs, and ZECs. If we pick $42 for the price of carbon, and the RGGI price is $10, then our effective carbon penalty we'll put in the market is $32. Now, as this $32 penalty goes into the market, it will come up with more efficient outcomes. And as we move forward, the need for the RECs and ZECs will diminish. Now, we don't know whether $32 is enough to get to the 50% renewable target, and that's why we leave the state to set the price, whether it should be $32, or $52, or $28. They can adjust it.

Now, the stated policy is to reduce carbon by 40% by 2030, but there is also is the policy of 50% renewables. I mean, if the policy is having renewables, by itself, that really doesn't get you anywhere if your objective is to reduce carbon. But the state governments have other objectives. For example, they like to pick and choose technologies, too. So, say that we give a price of carbon and all we are getting is onshore wind, but they like offshore wind. So, they might say to onshore wind that the Tier One REC, you don't need it anymore, because the carbon price is sufficient, but we are giving RECs for offshore wind. So,it leaves the option for them to do their thing. So, REC, ZEC, RGGI, and carbon pricing can all coexist. The most efficient way to do it would be to put on a carbon price, and adjust the carbon price till you get the public policy outcome. But the public policy outcome, almost by definition, is ambiguous.

Respondent 4: I actually think your question is composed is of two separate questions. The first one is, does a state RPS survive and coexist with the regional carbon price? And the second one is the scenario you outline, which is, what happens, or what would happen, if the costs go too high under the combination of the two regimes?

I really think there are two separate questions there. The first one is implicit in what Speaker 3 just said, and it's also really an outcome of both the Supreme Court's discussion of concurrent jurisdiction between the federal and state governments in *EPSA*, and the discussion in *Hughes* about state programs, as long as they're not tied and focused explicitly to the wholesale markets, as RPSes, by definition, the way they're written, are not. So it seems to me that the state programs would survive the implementation of the pure energy market carbon price that I had in mind.

Now, your question really is, what would happen if the combination of the state incentive driver and the wholesale market carbon adder threatened to bring consumer costs too high? We need to look at that, really, in two different time scales. The first one is what happens at the outset. The second one is what happens after implementation of a program. And it looks like the result is much what you anticipated. I would expect a 206 challenge at that point by someone who says that wholesale rates are too high. At the outset, I would expect that much of that would be cured by the discussion among states and stakeholders leading to the carbon price itself, and whether something like what Speaker 4 described was actually baked into the price itself from the get-go.

That is, your question almost presumes that the discussions would go down two separate policy tracks, and I guess my hope would be that they wouldn't. And what I see happening in the NEPOOL discussions is a sense that it's meant to be responsive to the mandates that the states have, Connecticut and Massachusetts in particular, but it's also meant to produce an outcome that would avoid the situation you describe. Maybe I'm just being naïve about that, but at least that's what I see of the discussion so far.

Quesiton 3: Thank you very much for these presentations, which I thought were very interesting. If I have to vote today, I'm going to vote for the Speaker 3 and Speaker 4 solution here, which is this put the charge on carbon approach, and the story that you tell is very impressive and persuasive to me.

I'm going to argue, or at least ask if it doesn't go far enough, the story that you're telling. One of the most outrageous things that happened in New York when they were promulgating the Clean Energy Standards and talking about the program with the leadership was that they were asked if this is consistent with the Public Service Commission's vision, the Reforming the Energy Vision initiative in New York. And the answer was yes, which is exactly the opposite of the reality. That's because Reforming the Energy Vision has two components to it that are relevant here. One is that it's focused on distributed energy resources and demand response and all the stuff down in the distribution system, on the customer side of the story, and all these other things that are coming along. That part's OK. That's good. And the other is what Audrey Zibelman calls "transactive energy" on this new platform where parties are making voluntary choices in order to do things that are economic from their perspective and trading with each other and doing all these kinds of things. And Speaker 3 and Speaker 4's putting a tax on carbon is consistent with that, because it's sending the price signals to those people that this is really a good idea and you should do it, and it's better than the alternatives on the wholesale side, and better than zero energy credits and directed subsidies to renewables, which actually lower the price in the energy market and cause some of the problems that you're talking about, and then socialize all the costs that can't be avoided, so they work in the exact opposite direction. And then you're going to have the problem of having to create new mechanisms to get people to do more distributed energy resources than is economically appropriate, given the prices that they're seeing at the moment, and so forth. So the whole thing becomes very intrusive, and it completely unravels the Zibelman vision. So I think you should be pushing here why this is actually the way to go in order to achieve the benefits of Reforming the Energy Vision. It's not enough, but it's certainly a necessary component.

Respondent 1: I think we would agree. I think even the supporters of the RECs and ZECs would agree as well, because one of the big things, as you know, is that they want nodal prices. The load in New York gets an average zonal price. To get the best outcome for distributed resources, you need the nodal price. So the state has been saying, why don't you publish your nodal prices, and they would do the distribution price based on the wholesale price of the node. So it doesn't make any sense to suppress the wholesale price, if that's your premise. So the RECs and the ZECs really don't support that. We can certainly point that out to them. [LAUGHTER]

Quesitoner: It's worse than they don't support it. They work in the opposite direction in a big way, and that's the problem in California. They're suppressing all of these prices, and so then you have to have some way to come around and undo the effect of the thing that we just did through this. [LAUGHTER]

Question 4: Thank you very much for putting this on the agenda. I thought it was an excellent panel. I think this is really one of the biggest issues we're going to be working on for the next few years. Thank you, Speaker 2, for your analogy of the prenup or the premarital counseling. I'll definitely steal that when I'm in the West.

Speaker 1, in your remarks and in your article, you pose a hypothetical of a region that comes up with a consensus carbon price. You answered the question of whether FERC could jurisdictionally approve it as a practice affecting rates. We just heard an economist say it makes economic sense. I'm hearing from the Pony Express that's coming in from the regions that a lot of other things are being talked about besides the pure carbon price, in part to accommodate both the visibility issues of a carbon price that Speaker 2 spoke of and the political preferences of different states. And we're hearing about changes in the capacity markets, premarkets, tranching, two tiers, etc., etc. So, I wanted to try out a different legal theory that's floating in the ether. If a lot of states in a multistate region have various different carbon policies wanting different things, do you think an ISO could come in and say, "Our market will no longer be just and reasonable unless we adapt it to the state situation. Therefore, some adaptation is necessary to keep our market just and reasonable, and keep it right in the middle of that just and reasonable standard?" And for extra credit, do you think it matters if it's a 205, or do you think that that could even be a 206 argument?

Respondent 1: Let me start with the first part of that. I think I had, on one of the slides, that that is the obvious policy driver for the discussions in NEPOOL, for the discussions (at least at the early stage) in PJM, and the discussions in New York. I don't believe, based on what I have seen in the analysis, that that would be a sufficient basis for a conclusion that the carbon price was warranted. I think it would have to go more toward the overall system attributes, and not the state law attributes that we're discussing here. And there are other aspects of this that I'm seeing in the discussion, like a concept of what the actual price is. And I think you would see review of that choice of number later on in judicial review as to whether the choice was arbitrary and capricious. And Speaker 4 and I had a discussion about whether you could adapt the EPA social cost of carbon, which was chosen for federal government-wide rulemakings, and use that for a completely different context here, for pricing in the wholesale markets. But I don't think that simply adapting to the states' policies is sufficient justification for a carbon price. And now I've forgotten your second question. What was your second question?

Comment: 205 or 206.

Questioner: I didn't mean just simply a carbon price, but if an ISO or region comes in and says, "We want to change our market in some way because of these state climate policies." If it was a carbon price, it might actually be the most easy to understand way to do it compared to some of the —

My second question was, do you think someone could ever affirmatively use 205 or 206 to make a case for a consolidated policy?

Respondent 1: So obviously, I've analyzed the pure situation, which is when a region brings it to FERC as a filing. Obviously, as Speaker 4 mentioned, the burden of proof question of a challenger challenging rates in a region as unjust and unreasonable under 206 comes into play there. It seems to me that the more logical way that carbon pricing actually happens is by a filing. I'm not trying to skirt the question. I'm just saying it would be more difficult if a challenger comes up and says that it would be unjust and unreasonable on that basis. And there, again, I do take notice of the fact that there are discussions underway to do this in a variety of different flavors, whether it's in the energy market, or whether it's in a multi-tier capacity market. And I had discussions with several people at the break about why I chose the energy market to focus on, and I said that was simply because it's the hardest case and illustrates the most difficult analytical challenges here. I hope that helps.

Question 5. First, to paraphrase Samuel Johnson, nothing focuses the mind of those of us who believe in markets more than wildly out of market potential solutions, and I think part of what really drove the process of IMAPP (Integrating Markets and Public Policy) in New England was the legislative action by the State of Massachusetts, with long-term PPAs coming down the pike for hydro and for up to 1600 megawatts of offshore wind. And in a system that on a given day is 14,000 megawatts, that obviously can have an enormous impact on markets, so that the need to try to find a solution here is really very powerful.

I frankly came away from your discussion, Speaker 1, feeling rather discouraged, because I personally like the idea of the shadow carbon price. And now you've raised a series of issues that obviously we need to address.

I think we have to have some more joined-up thinking between markets here and what physically can be done. In New England, as a practical matter, if we're going to have a lot more renewables or zero carbon, it's going to come from Hydro-Quebec or it's going to come from wind in Maine, at least over the next decade or so. And maybe some offshore. And the issue here is transmission. And that, to me, is the missing link that's not discussed in the carbon price directly. And as a practical matter, as we know from our own analysis and our external market monitor, wind today already receives more than enough money, between the production tax credit at the federal level, as well as the state RECs. It's on the order of $60 per megawatt hour. It's above the cost of no entry. Wind doesn't need any more money to be there. The issue is transmission. And so, if you were to, instead, look to a policy that socialized transmission and build additional efficiently sized transmission capacity to Maine and up toward Canada, and then you allow the resources to compete in existing auctions, my hunch is that you'd be very close and wouldn't necessarily have to do much else in the market whatsoever to have them be competitive. That's still obviously a subsidy that you're putting in there, because you're socializing additional transmission. But at least you're more in the vein of a market solution than a lot of other things that are being discussed, and frankly this is akin to what ERCOT has done, or what Texas has done in building the transmission lines out to west Texas.

So I think that's something that needs to be really taken into account. It's making sure that the policy intersects with what physically would have to be done in an efficient way.

And the last point I'd make is that if we ever get this far and we get shadow pricing, I think two tiers is very likely. Because people, frankly, are going to take a hard look and say, "OK, we recognize the nukes need something. We'll set that carbon price that benefits all zero carbon resources at what the nukes need, and then whatever else is there in the existing REC system is the extra that the wind guys and the solar guys will get. That's OK." My hunch is that, politically, that's more tenable than just having one high price that benefits all the nuclear electrons equally to the wind and solar electrons.

Respondent 1: I didn't mean to discourage you. I actually think that casting the Commission's authority in the sense of reliability as a proxy, I think gives it far more authority. I mean, my article is titled, "FERC's Expansive Authority to Transform the Grid." I think there's more authority there than some people think there is. But if you think back to the question that was just asked me, I don't think the Commission has the ability to say, "We're doing this because Massachusetts has a Global Warming Solutions Act." It has to be what is appropriate for the particular resource of the particular region.

Now, as far as transmission goes, we were asked to talk about carbon pricing and not Order 1000. I think there's enormous potential benefit to the approach that you're talking about.

Questioner: Just to follow up. The CEO of the ISO, Gordon van Welie, has been making clear statements about the issues of reliability arising from renewables as well as a constraints on natural gas pipeline systems. So turning it around to an argument that reliability's enhanced by more renewables is going to be, I think, a bit of a stretch.

Respondent 2: The one wrinkle, I might add, is just that it may be that the CREZ and what Texas did was, I think, easier to do, perhaps, because the renewable resource is in Texas. And the context where you are talking about one state having a renewable target that's very aggressive, that implies significant costs, and having a lot of that resource sited in other states, is a trickier thing to justify. At least in the California experience it has been.

Questioner: I understand that's an issue. I think that could be potentially manageable now.

Respondent 3: I don't have that much more to add, other than I just love everything you said. I think these are all examples of things we've got to work through, and the suggestion that at the end of the day, maybe there's a political compromise here is exactly what I was trying to say at the beginning. There are a lot of things in our way, but if we could sort of envision a state where everybody gets a little bit of what they want and gives up something that they think they have now, then that's a pathway to get something in front of FERC that they all can see that this is something that they can defend and support. I'm glad IMAPP is going to focus on the legal issue on October 21st. I think it's just all part of the process of getting to what's the best way we can support something that everyone agrees is the right answer.

Question 6: How dependent is New York ISO on the renewable resources coming from inside the state versus outside the state? Speker 3, in your presentation, I thought I sensed you saying it was good that the state is going to allow external to New York resources to be eligible, and your chart had a big number for importing into New York. But if, for whatever reason, on a practical level, that started not to play out, how big of an impact is that to the New York ISO to have most, if not all, of the necessary renewables required to be built in New York, and you have to handle that?

Respondent 1: We welcome the fact that the state policy allows for ISO resources to participate. And in terms of the ways that we can get to 50% renewables, there are different combinations. I mean, one combination that we've chose in that pie chart was there was 5,000 megawatts of wind and 9,000 megawatts of renewable and a small increase in hydro from Hydro-Quebec. Now, you could have more hydro and, say, less wind. So there are different combinations where you can get to that 50%, and that's why we'd like to make the markets work. If you give the price, and you have to figure out which renewable resource competes, the actual percent of different technologies will fall out.

The other thing with the hydro, particularly Canadian hydro, is that it goes with the transmission aspect of it. Even today in New York, we are reinforcing two major transmission corridors, another FERC Order 1000 public policy initiative. And these go through the ISO process, and this is probably the first time in New York in 30 years that a major transmission upgrade is being planned. So, depending on the options, if there is more hydro from Canada, you would need maybe additional transmission. You might need more transmission even with wind options. The state has identified two public policy projects, but there may be more feeder and collector systems needed to get that to the main highways and get that to the load centers.

Now, the question is whether you would let a carbon price drive the resource mix, or the state might incent certain different combinations to get to that 50%.

Questioner: The reason I raise it is that other people were talking about whether states would look at an ISO carbon price as a legitimate path to getting to their goal, or they would try to drive it themselves. As a load serving entity, the retail supplier is going to have to demonstrate compliance with the state's initiative with eligible RECs, and I can tell you, it's not the model for everyone, but in many cases, everywhere else, when you buy a REC, you're not contracting for the energy, nor are you showing a delivery point, a sink point, and my understanding of the New York Clean Energy Standard, as written by the Commission, is that an out of state REC is only eligible in New York if you're also contracting for the energy and you're delivering that energy on a transmission path into New York.

Respondent 1: That's correct.

Questioner: That's just not the way we buy RECs. So, if I buy a Pennsylvania REC and I decide to use it in Maryland, I don't have to buy the energy, and, quite frankly, I don't even have to go bilateral with the producer. It's a fungible, almost financial, product. And I might hedge regular supply, also financially, not physically. So your assumption about the state counting outside of New York RECs as eligible to be turned in to achieve the state's goal could be undermined by the very practical way the load serving entity buys RECs, and the load serving entity just might decide that it's easier to buy from NYSERDA, and therefore you're really dependent on in-state renewables, and it just comes up when the state's going to evaluate whether you're going to get them to their goal, or they have to do it without you.

Respondent 1: Again, that's why putting a price on carbon, and using that to drive to that 50%

renewables, is probably the most efficient way to go about it.

Question 7: I wanted to follow up on the idea of a reliability rationale for a carbon fee, and I actually think that's not a very good basis for that, in part based on knowing that reliability has been invoked to justify a lot of evil in the electric industry over time. [LAUGHTER] And when I hear someone say, "We want to do this for reliability reasons," immediately alarm bells are going off. [LAUGHTER] Because that was the argument against QFs, non-utility generation, open access. Even more recently, New Jersey and Maryland invoked reliability for their price suppression scheme. And it's also an awkward position for FERC to be in, right? If you then blend in fuel diversity…fuel diversity now is sort of the clarion call of the uneconomic resource, right? Well, we have a very diverse electricity supply, but that's not reflecting a commitment to diversity. It's the consequence of herd mentality chasing what everyone perceived to be the lowest cost fuel or technology at a given time. So it's the consequence, it's not the object. But I just can't conceive of FERC looking at Speaker 3's New York chart, and saying, "You know, we need 31% dual fuel. I don't think 28 or 26 is quite right." I just can't conceive of FERC doing that. I would think the best scenario would be that the Clean Power Plan is found to be lawful, and a region with a number of states uses the discretion rule to choose to adhere to a carbon fee. It's presented to FERC. The question to FERC then is, are we going to facilitate a region's compliance with a federal law that's been affirmed by the courts? That's a pretty discrete question.

Respondent 1: It's not a federal law. It's a federal regulation.

Comment: I think if FERC has authority to approve it, they have authority to impose it under 206.

Respondent 2: We've had many discussions about this sort of thing over the years. To the first point about reliability, and I agree that the word has been tossed around to prevent useful initiatives from coming to the fore, this is a different conception of what regional reliability means, and it's one that's advanced by the Commission itself and not by, let's say, an incumbent distribution utility. I think the awkwardness comes in part from using it as a proxy for something the commission cannot do directly, and that is to say that we are doing this to internalize environmental externalities. I do not believe, under current case law, that an order that said, "We're doing this to impose a social cost of carbon in ISO New England or New York" would be successfully defended in the courts. And so it is true that speaking to reliability is a bit of a workaround. There's no question about that, but I think the fact that that word has been used in other contexts for different purposes by different entities shouldn't prevent the Commission from defending it here.

Now, as to the Clean Power Plan, I wrote an analysis without discussing the Clean Power Plan mostly because, as I pointed out in my opening remarks, I was focused on *FERC vs. EPSA*. And it's a very, very different analysis that actually is more of a Clean Air Act analysis if a region chooses to get together and do carbon pricing. I'm fairly certain that some of the state-level discussions for compliance with the Plan did, in fact, contemplate the potential of carbon pricing as one option that could be incorporated into state plans or multistate plans. To me, that's a completely different analysis than the one that we're talking about here that is simply the Federal Power Act.

Question When we look at a carbon price, which I think is probably a good idea, ultimately, it doesn't get us to the point we need to make a renewable project financeable. You're still going to need some sort of long-term price. But what carbon pricing does really well is drive coal to gas switching and make new efficient gas plants very economic. And so one of the things that I worry about a lot is that 2030 almost seems easy, but 2050, if you look at the climate targets we're aiming at, just moving to gas today means you have more carbon emissions than our national budget allows for just about the entire economy, never mind the energy sector alone. So I wonder, how do you escape that with the carbon price, because it seems like you still need to go, not from coal to gas, but from coal to renewables, and the carbon price by itself just doesn't get you there, and, in fact, reinforces the negative long-term trend of moving to a largely gas system. Do you have any thoughts on that?

Respondent 1: This has been a big issue in IMAPP. And I just don't buy it. I just don't buy that you can't finance a new renewable project without a long-term PPA. Obviously, there are plenty of generators in the room that develop new generation all the time without having a long-term PPA. If you have a price on carbon in a FERC tariff that can't be changed without the Commission taking affirmative action, it's the filed rate. And in New England, where you have, in addition to that, in the capacity market, a seven-year rate lock at the price you've set, I'm just not buying that that's not a financeable model. So, if I don't agree with that premise, then I don't follow the problem. And I could be wrong, but that is just how I feel about it.

Questioner: No, no, and I actually agree. One of the things I love about New England right now, on the fossil fuel side, is the seven-year price law. It just proves we can do these kinds of things. We can create a financeable mechanism through the market mechanism. So I don't think we necessarily have to restrict ourselves to a long-term PPA. But whatever the mechanism is, I think that the premise is still there. You need that long-term arrangement for most renewable finance projects.

Respondent 2: I think there's an important distinction to be made, in terms of financeability, between cap and trade and carbon taxes. And what I have heard Speaker 4 talking about today, sounds more like a carbon tax than like cap and trade. And I agree that bankability is tough with a cap and trade system, particularly where there are a lot of technical decisions that have to be made later about how the market is structured that's going to drive the ultimate carbon price, and may drive changes in that price. But I think the discussion we've been having today has mostly been focused on things that sound more like a fixed and predictable price trajectory, and that that kind of policy might fare much better, in terms of its financeability. Might.

Respondent 3: OK, I just want to say I agree with Respondent 1. I know, as a developer of renewables, that you want to have a fixed contract, but we would make the proposition that you don't need it. We have seen that in markets, with price projections and price discovery in the short term, we can make long-term decisions. I know why you would want to have a long-term price thing, but that's not what the markets are meant to provide.

Question 8: We seem to have sailed by what I think is a stumbling block, and that is, we can have regional carbon prices. Suppose New England or New York adopts a carbon price, and FERC says that's just fine. Doesn't that become an interstate market carbon price? And since carbon is not a local public good, it's a global public good, it should be the same all throughout the FERC regulated markets. And what is to then prevent somebody like Speaker 4 saying, "Well, you adopted an interstate carbon price in New England, now you've got to do it in MISO and in PJM?" And since the argument is is that there is only one carbon price, how do you say, "No, you can have a carbon price of zero in one region, and $42 in one region, and $80 in another region?"

Respondent 1: I thought I answered part of that at the end of my presentation, in that I see there being a difference in legal burden when something is being proposed to FERC as just and reasonable, versus someone who's asking FERC to declare that something that's already on file is not just and reasonable and has to be changed.

The rules say you have to go to the opposite side of your complaint first. So if I wanted to make a complaint about a jurisdiction not having a carbon price, I'd have to go to the individual jurisdiction first and ask them, and then I would have to come to FERC.

But to the issue about whether it isn't more economically efficient to have a single price across the country, sure. I don't disagree with you there. I don't think that means that it's not a second-best alternative that's better than what's out there to have the price be the same across an RTO footprint, particularly when the cost of reducing carbon in one RTO could be different than in another RTO. I don't purport to be an economist. But I don't see why, just because it's not nirvana, it's by definition not economically efficient.

Question 9: An earlier questioner said out loud something I'd been thinking about, and that is, today we've been talking about what success would look like in terms of reflecting the price of carbon in markets, but I think we need to step back and, more broadly, think about how that can be achieved. How do you get to success? And as I've been engaging with a number of RTOs and ISOs and stakeholders who are working on these issues, I see a top-down approach and a bottom-up approach. Top-down, obviously, New York. And maybe even, if you look at the work happening in California, they are doing it. But looking at, for instance, their governance model and how they get to success with the top-down approach, I think it's fascinating to watch governors riding each other. Having worked in a cabinet, I think it's quite remarkable. Multipage letters about governance in RTOs and ISOs. I think it speaks to the elevation of these issues. Clearly, a bottom-up approach, from my history as a state regulator, would tell me there's more of an opportunity for input from traditional stakeholders in the RTO/ISO process. There's an opportunity to build consensus. It takes longer. And it actually may not reflect, now, the very real overlay of political will, and I think we'll watch ISO New England and see if they're able to get to it.

I think we need to think about how we engage reality with what we're trying to achieve. And so, the point about transmission planning is a very real one, looking at Speaker 3's slides, and, good grief, all of the transmission you guys need to build by 2030. And we're going to have to do all of this in tandem. I tell people that this job is like juggling riding a unicycle and chewing gum all at the same time.

But getting to the point that some have made about what we mean when we invoke reliability, it's clear that we have honored diversity, and, yes, maybe some could argue that there have been iterations that focused on a particular source or another. But I really am pleased with the beauty of the current model as highlighted today, where you all are trying to work to find the best solution and bringing it to us. I think that's the best way to do it. I don't think any other way will work, but I would just offer as food for thought, that it may be well for us to keep an eye on these different models and how we get to success.

Speaker 4 mentioned the Grid 2020 initiative that PJM has. To me, that's the greatest challenge that we will collectively face in the years going forward. It's not just carbon pricing and factoring that in. It's addressing and dealing with these new and different tensions from a number of places. Not just states, tensions with local entities, with public power entities, and others, and how we master that in a practical and real way.

Question 10: I'd like to just really underline what the last questioner was talking about. This is exactly where we are right now in looking at a regional ISO in the West. We're trying to figure out how we get there. And if you look at the primacy of the issues that we're currently discussing, the first one is governance. How do we get from a five-member board appointed by Governor Brown to a nine-member board that's independent? But the other primary issue is preservation of state authority. And when we talk about preservation of state authority, we're talking about generation choices, the IRP process in each state. We're talking about how we address the broad diversity of the RPS standards in the Western states. And how do we collaboratively figure out a way that we can address all the issues from all the competing interests in the states, but do it in a way that we get to something that could potentially be very beneficial to all of us, which is this regional ISO? I think those issues are the ones that are going to be the thorniest, and, at least for me, this has been a very useful discussion. I'm going to leave it there, but this has been a great discussion this morning, so thanks.