BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

CONSENT MARKETS, TARIFFS AND RATES - ELECTRIC :

MISCELLANEOUS ITEMS :

CONSENT MARKETS, TARIFFS AND RATES - GAS :

CONSENT ENERGY PROJECTS - HYDRO :

CONSENT ENERGY PROJECTS - CERTIFICATES :

DISCUSSION ITEMS :

STRUCK ITEMS :

- -x

826TH COMMISSION MEETING

OPEN MEETING

Commission Meeting Room

Federal Energy Regulatory

Commission

888 First Street, N.E.

Washington, D.C.

Wednesday, April 30, 2003

10:10 a.m.

APPEARANCES:

COMMISSIONERS PRESENT:

CHAIRMAN PAT WOOD, III, Presiding

COMMISSIONER NORA MEAD BROWNELL

COMMISSIONER WILLIAM L. MASSEY

ALSO PRESENT:

DAVID HOFFMAN, Court Reporter

P R O C E E D I N G S

(10:10 a.m.)

CHAIRMAN WOOD: Good morning. This open meeting of the Federal Energy Regulatory Commission will come to order to consider the matters which have been posted in accordance with the Government in the Sunshine Act for this time and place.

Please join us in the Pledge to the Flag.

(Pledge of Allegiance recited.)

CHAIRMAN WOOD: We had a few items struck from today's agenda, and we will get to those, hopefully by the next meeting, if not before, but we do have a number of other items, and I want to thank everybody for their work, as always, that goes into getting us prepared for these meetings. So, Madam Secretary, it's yours.

SECRETARY SALAS: Good morning, Mr. Chairman, and good morning, Commissioners. The items that were struck on the agenda since the issuance of the Sunshine Notice on April 23rd are as follows: E-4, E-7, E-9, E-10, E-14, E-16, E-28, E-30, E-38, E-39, E-40, E-45, E-47, E-55, and G-2.

Your consent agenda for this morning is as follows: Electric E-5, E-6, E-8, E-15, E-18, E-19, E-20, E-21, E-22, E-26, E-31, E-49, E-54, E-56, E-58, E-59, E-61, and E-62.

Miscellaneous Items: M-1; Gas Items, G-1, G-3,

G-4, G-5, G-7, G-8, G-10, G-11, G-14, G-15, G-16, G-17, G-18, G-20, G-24, G-26, G-27, G-30, G-37, G-39, G-40, G-42, G-43, and G-44.

Hydro Items: H-3 and H-4; Certificates, C-1, C-2, C-3, C-4, C-5, C-7, and C-8.

The specific votes in two of these items are as follows: For E-6, Commissioner Brownell concurring with a separate statement; and for G-14, Commissioner Brownell dissenting with a separate statement.

Commissioner Massey votes first this morning.

COMMISSIONER MASSEY: Aye.

COMMISSIONER BROWNELL: Aye, noting my concurrence on E-16 and my dissent on G-14.

CHAIRMAN WOOD: Aye for me.

SECRETARY SALAS: The first item in the presentation agenda this morning is A-1. Mr. Chairman, you have some remarks?

CHAIRMAN WOOD: We have a program here called e-Subscription. It's the series of wonderful programs that we're doing to join the new Millennium, all of which begin with a small letter-e.

e-Subscription is the ability for customers, a free service provided to work smarter within and without the Commission. We have a laminated card and we want to encourage people in the audience, as well as people at their home computers or their TVs or their closed-circuit TVs, however people are sharing this, to look at our web page at ferc.gov under e-Subscribe Now, which is a button you can toggle on the front page.

e-Subscription is for anyone you want to keep track of projects, dockets, or issuances on projects here before the Commission, for landowners and others that are affected by gas and hydro projects that are proposed, and, of course, our friends in the press and financial communities.

Our staff has been a frequent subscriber, as well, to this new program, and, again, one or multiple people can subscribe. From our perspective, there's not an additional transaction cost, whether it's one or 100 people who are getting it.

Whether you subscribe to a docket or to press releases, you will be notified via e-mail about future correspondence that comes in and is issued by the Commission. You can simply download and print it or leave it on your screen. This saves time and dollars and reduces the need to go through FERC's website, and so you can certainly see our vested interest in avoiding to have to get a bigger T3 or more T3s to our website.

It also eliminates the need to have to search FARIS on a daily basis for the dockets that you may be interested in following. I'd like to ask those of you here who can utilize this service and watching right now, to ask your staff to subscribe or subscribe yourself.

Over 775 folks have benefitted from e-Subscribe now. We hope those cost savings are being passed on to the ultimate customer.

Anything else to add, Madam Secretary? I want to thank you and I want to thank the IT staff and support administrative staff for bringing this program to the fore. We look forward to many more good things in the little, small letter-e category as we go through the year.

SECRETARY SALAS: I should add, Mr. Chairman, that this wonderful program is now being overseen by the Office of External Affairs, and they are doing a very good job on that.

CHAIRMAN WOOD: Thank you all. All right.

SECRETARY SALAS: The next item is A-3. This is a state of the market report by regional market monitors. It is a presentation by Amjali Sheffrin of the California ISO, Mr. Robert Ethier of ISO New England, and David Patton, Consultant to the Midwest ISO. Mr. Hederman, I understand, has some remarks.

MR. HEDERMAN: Thanks, Madam Secretary. I just wanted to welcome our colleagues, the market monitors for three of the five presentations you'll be getting. The other two will come at the May 14 Commission meeting.

Anjali Sheffrin, Bobby Ethier, and Dave Patton are here. I hope you'll notice that the beginning of some standardization has begun. We've all bought into the idea that we need to help you to be able to compare the information from each of the markets.

Of course, David's information from ISO cannot be put in the same format, given the state of the market from ISO at this point, but I just wanted to welcome these colleagues.

We've really made great strides in working in a partnership relationship with the market monitors, and I think we are all benefitting from those efforts. I'll pass the ball to Anjali.

MS. SHEFFRIN: Good morning. Thank you for inviting us here. I'm please to present to you, the state of the market in 2002 for the California ISO's markets.

(Slide.)

MS. SHEFFRIN: Let me continue while the presentation comes up. We also have prepared a state of the market report that we will be ready to file with the Commission for your review, which has a lot more detail. I'll just try to go over the overview this morning.

The California ISO operates a large interconnected transmission grid, transporting wholesale power to ten million customers. The grid is 25,000 circuit-miles of network.

In 2002, the peak demand was 42,400 megawatts, and the annual energy consumption was 232,000 gigawatt hours. Inside of the control area, we have 45,000 megawatts of installed capacity prior to de-rates for hydro available and thermal outages.

When you take those into account, it's approximately 40,000 megawatts of installed capacity within the control area. We rely on a large amount of imports, as you know.

Last year was a good hydro year for the Northwest, therefore, California got net imports of 5,000 megawatts on the peak hours.

Let me continue on. The current market that the ISO runs is the real-time and balanced market, five ancillary service markets, and the day-ahead and hour-ahead congestion market. We do not have a day-ahead energy market, as you know. The Power Exchange operates that, and went out of business in 2001.

(Slide.)

MS. SHEFFRIN: The major changes that we have had in the market in 2002 are mainly associated with the bidding rules for imports into our real-time imbalance market, as well as the bid cap.

In February, the Commission told us that in order to solve the problem of megawatt laundering, that import bids have to be at zero. We were concerned about that. We filed with the Commission in April.

They essentially said they could be paid the instructed price, rather than face the risk of bidding zero and also not knowing if they were going to be able to recover their costs in their market.

In May, we also improved --

CHAIRMAN WOOD: Did that resolve the issue through the Summer?

MS. SHEFFRIN: We're concerned it hasn't. We've seen import bids go down again, so in what we call Phase I-B, which the Commission gave us authority for, it comes in October.

Unfortunately, that will help some, but we will be watching that situation through the Summer. Fortunately, we've had some good hydro, so we're hoping that the supply is there, and that they will want to sell to California.

CHAIRMAN WOOD: While we're looking at this -- and this is why we do these before the Summer, with you all -- is there something on that issue? I know that it wasn't a slam-dunk either way.

MS. SHEFFRIN: The Commission as attempted to help us out. I think it's just a matter of timing.

Unfortunately, that Order, so that they can get paid, but not set the market clearing price, that will help somewhat. That still doesn't go into effect in October, just because of our software changes. We're putting all the changes into together.

CHAIRMAN WOOD: Can you remind me what it was that your division, Dr. Sheffrin, had recommended as the solution for the import problem?

MS. SHEFFRIN: I think we had recommended that they be able to be able to state a price at which they're willing to sell. And we look at that price in dispatching them, so that they have assurance that they will get paid at least what they bid in, but still not set the market clearing price.

I believe the Commission did give us that, but, again, starting in October when Phase I-B goes in. If we find that we have problems in that area, we certainly will alert the Commission for any assistance we need.

CHAIRMAN WOOD: Do you have the ability to adjust that in shorter than the 60-day timeframe, if there was a kind of critical issue that comes up?

MS. SHEFFRIN: We will certainly look at that if we feel that it's going to be a threat to either market competitiveness or reliability. We would make an emergency filing.

CHAIRMAN WOOD: Okay, because we just did something similar in New England with their new local power market congestion methods. That gave them the ability to suspend, with some high standards, but to suspend in a relatively expedited format under a new market rule, if it's not working as projected.

COMMISSIONER BROWNELL: If I understand you, the reason for the October introduction is a software issue, not anything constraint we've put on in terms of dates.

MS. SHEFFRIN: No, you gave it to us in Phase I-B. Phase I-B was originally supposed to come in prior to the summer. Unfortunately, the software has delayed it, but I don't think it necessarily has to be tied to the software.

COMMISSIONER BROWNELL: So that is what you would do in the event of an emergency?

MS. SHEFFRIN: In the event of an emergency, we would ask that what you already gave us to move that forward --

CHAIRMAN WOOD: Just a manual version of it?

MS. SHEFFRIN: Right. Also --

COMMISSIONER MASSEY: Excuse me. I remember thinking maybe I was misinformed. I remember thinking at the time that I wanted you to have that authority for the summer, if we were going to change the rules. I thought maybe it would be available to you this summer when you might need it, but it's not going to be?

MS. SHEFFRIN: Right now, it isn't. The Order says it goes in with Phase I-B, but certainly if we feel that it will be a problem, we will ask the Commission to move that forward.

CHAIRMAN WOOD: If you want to do that in advance, as New England has done, I don't think we have heartburn on that, to just kind of have it in the packet, rather than having to go through an emergency.

MS. SHEFFRIN: And wait till something happens, okay, great.

The other major market change that occurred in October was that $91.87 was replaced with a $250 bid cap, and a mitigation procedure, mitigating individual bids, was put in, called AMP. I do want to tell you that no mitigation has been invoked under the new AMP procedure, just because the thresholds are so high.

COMMISSIONER MASSEY: But the AMP program is in place now?

MS. SHEFFRIN: The AMP is in place.

COMMISSIONER MASSEY: The software is in place?

MS. SHEFFRIN: Yes, but it hasn't triggered mitigation yet.

COMMISSIONER MASSEY: Okay.

(Slide.)

MS. SHEFFRIN: The thing with my report is that overall, there's been tremendous improvement in the marketplace. What I'd like to do in this report is go through some of the market structure issues, assess market competitiveness with you, then review the performance of each market.

So the key elements of market structure are: Demand conditions, supply, and assessment of overall competitiveness.

(Slide.)

MS. SHEFFRIN: First, let me go through just the overall cost of serving, the wholesale electric cost of serving load.

(Slide.)

MS. SHEFFRIN: In 2002, the wholesale cost of serving load was $10 billion. That was a vast improvement from the $27 billion to serve load in 2001 and 2000. That's mainly because in 2002, we did have most of the demand being met by utility-owned generation, long-term contracts.

The volumes in the real-time market remained very small and the cost to serve load in 2002 was still higher than in 1999, mainly due to two conditions: One, we saw higher natural gas prices and also the higher cost of the long-term contracts factored into that total cost.

CHAIRMAN WOOD: I notice that even in the earlier years, the bulk of the cost is considered to be forward energy costs (bilateral). How do you define that for purposes of this graph?

MS. SHEFFRIN: In this graph, utility-owned generation and anything beyond the spot market, the way we define spot market is day-ahead and real-time -- day-ahead, hour-ahead, and real-time energy transactions.

So anything that took place prior to the day-ahead, I consider most of those transactions are bilateral.

MR. LARCAMP: The Commission didn't return the utility-owned generation until its December 15, 2000 Order, so why would the utility-owned generation that prior to that date was being run through the PX, show up as bilateral?

MS. SHEFFRIN: I don't think it is. I think we said utility-retained and bilateral together.

MR. LARCAMP: So the PX purchases are considered bilateral in the forward energy cost. That's the only way it could be.

MS. SHEFFRIN: I'm sorry, it also had the day-ahead energy cost in this one. Sorry about that.

CHAIRMAN WOOD: So day-ahead and utility-owned?

MS. SHEFFRIN: Int the dark purple, right, and then the real-time transaction is light yellow.

COMMISSIONER MASSEY: So the real-time

transactions would be only the hourly transactions?

MS. SHEFFRIN: In real-time, you know, five minutes.

COMMISSIONER MASSEY: An hour or less?

MS. SHEFFRIN: Yes. And then the ancillary services are just reserves that the ISO purchases in both day-ahead and hour-ahead markets.

(Slide.)

In terms of looking at load conditions, the first element of the market, we have demand growth, which was moderate, mainly due to low level of economic conditions as well as lower level of conservation by our consumers.

(Slide.)

As you recall, the consumers of California helped us get through the crisis by conserving a tremendous amount. We did see those levels declining. So total energy growth grew by about 2 percent, and there was hardly any growth in peak from the previous year. So this is a load duration curve. As you can see, it's just a small increase above last year, and hardly any increase in the peak.

In terms of the other component of load, price responsive demand, we have those under development, but they're not significant in the California market. We do have 1,400 megawatts of interruptible load, but those are based on system emergencies.

(Slide.)

So they really are not what we would consider price responsive. We also have 60 megawatts of load control devices, but in terms of price responsive load where they see the hourly price and choose to conserve or shift their consumption. My feeling is we're still lacking in that and we'd like to see more development in that area.

COMMISSIONER BROWNELL: Isn't Chairman Peavey making that an priority on his agenda? And I think that identified some initiatives. Do you have any idea when those are going to be introduced?

MS. SHEFFRIN: I have some information later in the presentation about a new initiative. We are still anxiously awaiting some real time pricing, but I think they want to go through a pilot program this summer, and that is going to get underway.

(Slide.)

Turning to supply conditions, we have 5,300 megawatts of new generation added since 2001 in California, we've been very busy on the generation front. We also have had 1,400 megawatts of retirements of old facilities, mainly in Southern California. So the net additions to supply since the beginning of 2001 was 4,000 megawatts of new transmission additions.

We have also approved 22 transmission projects, totaling about $700 million of transmission upgrades in California.

MR. LARCAMP: Have any certificate actions by the states been approved for those 22?

MS. SHEFFRIN: Most of them are what we consider reliability upgrades, and we hope those go through fairly quickly. We're done with our approval, and now the utilities will take them through on that.

CHAIRMAN WOOD: The process is the ISO does the plan, then the utilities within that footprint are then empowered to move forward and get the state approvals needed for the signing.

MS. SHEFFRIN: Right.

COMMISSIONER MASSEY: Bug generation addition means that it's actually on line producing power?

MS. SHEFFRIN: Our generation addition is on line producing power, right. At the same time of the new generation additions, we also saw an increase in supply due to improved generation outage coordination as well as a different incentive under the must offer. So we certainly saw very different behavior in our market in terms of scheduled and forced outages, and those were much lower in 2002 than they were in 2001, practically every month. So we're very pleased to see that.

The improved supply conditions meant that we had higher reserve margins. Most of the months it was greater than 10 percent.

(Slide.)

But on the peak hour, which is where normally the margin for the system is calculated, it was less than 6 percent last summer. So things still are tight in California and very much dependent on the level of imports that come in.

(Slide.)

COMMISSIONER BROWNELL: Could you speak a little bit to the future and your comfort level with the situation in which those imports were not available? Your comfort level in terms of how quickly these projects are going to be certificated, what the rules are between and among the marketplaces in the Northwest and the Southwest to deal with the gaming that we saw in the dysfunctional markets prior to this. Is there kind of a game plan in place that you could speak to?

MS. SHEFFRIN: Yes. We do a summer assessment. I believe it's on our Web site. We can certainly send a copy. But right now it's looking like things are going to work well. We've had a late hydro season out West. Finally it rained and snowed in the mountains, so things are looking better than they were during the first quarter of this year. I think we're taking a look at the new generation that will come on, but we do have some concerns about the new generation and its deliverability. Sometimes they tend to get stranded because the upgrades haven't been done yet.

Most of that generation should be deliverable, but some of it we do have a concern, and there's a technical conference on May 1st to try to deal with a lot of generation that has come in near Mexico, the Mexican border.

But overall, I think our assessment is that the summer should look okay just because the hydro conditions are much better, about 80 percent of normal, and they were much lower prior to this set of storms.

COMMISSIONER BROWNELL: I'm just doing a "what if" scenario. So we're okay this summer, we assume. But let's just say we weren't, and we have a tight year next year. Are the mechanisms, the rules and the structures and the transparency in place so that we could manage through a crisis more effectively? Are you comfortable about kind of where everybody is if that scenario should play out? God knows we hope it doesn't.

MS. SHEFFRIN: We should always prepare for the worst, and I think we're working with you to get the market rules in place to help the protection. I think the biggest one is our oversight investigation rules that we would like in place to help bolster our tariff, and we're going to make that filing very soon.

I think with those and the better communication we have with your office, Bill Hederman, you know, people are working with us to say the minute you find a problem, let us know.

(Slide.)

Next we take a look at the overall competitiveness of the market. We have a couple of competitiveness indices. We calculate how much prices are marked up above what we would expect in a competitive market.

(Slide.)

So there you have in blue are the levels of prices we would see in a competitive market. The gray is the markup. On average, the markup was about 17 percent for the year. It was about 35 percent in the summer months, but not of great concern to us.

(Slide.)

In order to take a look at the trend of competitiveness in our market, we calculate for you what we call the 12-month competitiveness index.

COMMISSIONER MASSEY: May I ask you, back on your previous chart, how do you calculate the estimated competitive price?

MS. SHEFFRIN: We essentially take a look at all the units that should be available because they haven't told us that they're on any outage, scheduled or forced, and simply stack them up and take a look at the hourly demand and say that should be the competitive price. Then we compare that to the actual price in the market and say how much of a markup is there. And you would expect some markup. Of course, we're concerned when that markup becomes excessive.

COMMISSIONER MASSEY: Stack them according to what?

MS. SHEFFRIN: Their incremental cost of production.

COMMISSIONER MASSEY: You're assuming in a competitive market, they will bid somewhat close to that?

MS. SHEFFRIN: Right. And we have seen that. It's not just a theory. We've been an operating market for five years now, so we have some history. That's what the next slide is supposed to show.

COMMISSIONER MASSEY: Okay.

MS. SHEFFRIN: What has historically been what level it was at the crisis and how it's come down.

MR. LARCAMP: With the run up on gas prices sort of sustained now, if we looked in 2003 more recently, would we see that relationship still holding, or have you seen changes since the end of last year as a result of the gas price? It looks like prices stayed relatively constant.

MS. SHEFFRIN: Actually, that is one thing we take a look at, what gas prices increase, what's the markup? We've been fairly surprised that even with the gas price increase, after we consider that, the markup hasn't been very high. That gave us some confidence that unlike the last crisis where that was an excuse to just mark up greater and greater amounts, we didn't see that this time.

MR. LARCAMP: Is that maybe because you were lowering the bid stack so more efficient units have to run?

MS. SHEFFRIN: Not really. In California, most of the units are at a very flat, very similar heat rate. It's not until you get to the end that it really goes up substantially. So in our price/cost markup, you saw we do take into account higher spot gas prices. That's why the blue bar is going up. With higher prices, the cost of production is increasing. We didn't see the markup increasing in step. That gave us some comfort.

MR. LARCAMP: If the $10/$2 ratio is a rough one, $5 gas will translate to $50, so you would expect that the spot price would be that plus the margin, and that relationship of the margin is holding constant.

MS. SHEFFRIN: No it hasn't, actually, with the run up in gas prices, as you saw, prices didn't go up proportionately. So the markup has actually decreased. So it's not a constant markup the entire time. Suppliers take a look at an opportunity that they have to raise prices, or if they don't feel they can, they don't, and mark up less.

MR. LARCAMP: Has there been a lot of import of hydro from the Northwest? I'm trying to look for the price signals for in-California generation, which presumably would be gas-fired. So that margin is important long-term for them siting additional generation in California.

MS. SHEFFRIN: I do look at that question of do our prices sustain new investment or not, so that will be an index coming up. Sorry. I'll go real fast.

(Slide.)

In terms of taking a look at the 12-month competitive index, what we saw was during the first two years of the market, the monthly markups are in pink, dark pink, and they were fairly low. Then as the crisis hit, that 12-month index rose. That's a rolling average, and that's in blue. And the gray bars are the volumes in the spot market, which is day ahead PX and ISO real time market.

So what you saw during the crisis was huge markups, fourfold, quadrupling and more. That along with large volumes being in the market, we had a big impact, and therefore, the culmination of the California energy crisis. The markups have come down substantially. They fell dramatically in July of 2001. And as you see with the red bar, the monthly markups have remained low. The 12-month moving average begins to fall and finally comes to a competitive level in May 2002.

So I think we can finally declare that the markets have returned to health and they are operating competitively right now.

(Slide.)

One other view that we take a look at is the residual supply index. That's a measure of both supply sufficiency and market competitiveness. Essentially, what this curve shows is the number of hours that the largest supplier in any hour can be pivotal in setting the market price.

So here is the RSI in a duration curve. The lower the curve, the more number of hours it's below the critical level of 1.1. So you saw in 2000 and 2001 where the worst conditions were 30 percent of the hours, the RSI was below 1.1. But in 2002 as the market returned to health, it was back at levels seen in 1999 where only 1.5 percent of the hours the RSI was below 1.1, or suppliers were pivotal and were able to set the price through their actions.

So again, another indication that the market has returned to health.

(Slide.)

To get to Dan's question, the other key issue that we take a look at is, are the market outcomes sufficient to support new generation or not? We took the cost of a new combined cycle using actual gas prices, heat rates. We simulated through the year to see how often it would run competitively, profitably. Then we calculated what its net operating revenue would be.

We added the ancillary service revenues to see what total revenues they would earn in the market as a contribution towards their annual fixed costs. Our simulation showed that the market revenue that a new combined cycle facility would earn would be $72 to $77 a kilowatt year, or $72,000 to $77,000 a megawatt year, which is about the cost of a combined cycle plant.

So, again, we had some confidence that our market prices would sustain new entry. But again, the best means to ensure new generation investment is through a long-term contract with load. It provides a much more steady revenue stream and assures greater financability of these new power plants.

So I don't think power plants necessarily should be built, quote, "on spec" just to sell into the real time market. A far more prudent course would be to sign a contract with load and take that to the bank and finance it.

CHAIRMAN WOOD: In thinking about the long-term contract part at the bottom, I know we had talked in the MD02 filing about the capacity market. I think it was referred to as ACAP in California. A 61 and 62 percent load factor. These numbers are what you say they are for the peakiness that you hit on those hours on the prior page when you do have the summer peaks -- I assume it's the summer, July or August. The load factor for a unit in that time is going to be quite a bit lower than 61, and I assume the economics are going to need a higher net revenue to support that sort of infrequently running unit.

MS. SHEFFRIN: Right.

CHAIRMAN WOOD: Is the ACAP program when implemented through the ISO going to address that? Or is there some other item addressing that more lower load factor unit that we're talking about here?

MS. SHEFFRIN: First of all, even though lower load factor units, the new peaking units are incredibly efficient. They won't necessarily have a load factor running only 100 hours a year or whatever. It tends to be one of the older plants who get put on marginalized in essence, and they have going forward costs that you need to compare to this.

But the ACAP program, we're not saying it's a market, we're just saying it's a requirement both operationally to show us that we know how we can meet our peak comfortably with the reserve as well as providing a vehicle to get those peaking plants financed for those who want to build it.

So, yes, we think they're the right incentive for both of those needs.

CHAIRMAN WOOD: Kind of looking at these, you would expect in a market that has some surplus that you would really see these numbers at pretty close to the cost of new entry. Again you said the 70 to 90 range was for combined cycle?

MS. SHEFFRIN: Right.

CHAIRMAN WOOD: A simple CT would be something higher than that?

MS. SHEFFRIN: It depends on the capacity factor and the heat rate that it runs at. I don't have the numbers, but I could calculate it.

CHAIRMAN WOOD: Seventy to 90 is based on the combined cycle?

MS. SHEFFRIN: Seventy is what's usually thought of; 90 is for a high-cost area, what it would take to recover, right.

MR. LARCAMP: On the operating costs, you're assuming a longer-term gas purchase?

MS. SHEFFRIN: No, we just did spot gas purchase price, not long-term gas. All those ways, they could save on that, and then get even more contribution towards fixed costs.

MR. LARCAMP: As gas fluctuates, that number would fluctuate.

MS. SHEFFRIN: It did fluctuate, right. Looking back at 2002 prices and then actual gas prices in 2002, as they fluctuated daily, I took that into account.

MR. LARCAMP: So if they had gone up since 2002, the $70-$77 number would float; if they've gone down, then they would go down.

MS. SHEFFRIN: Right, but prices were higher in 2003, as well. So we do take all those into account in this index.

Just going really quickly, because I want to leave time for my other fellow market monitors --

CHAIRMAN WOOD: You all are the only item on the agenda today.

MS. SHEFFRIN: Let me go through the performance of the individual markets very quickly.

(Slide.)

MS. SHEFFRIN: Here we have the prices in the real-time market. Essentially the prices vary from $40 to $60 a megawatt hour for most of the year, though you saw the fluctuations. There were numerous times where it did hit the price cap of $91.

This is for incremental energy, as well as decremental energy. What you see is a trend of prices going up to reflect the higher natural gas prices. That's what I'll show you next, is what natural gas prices have done in California.

(Slide.)

MS. SHEFFRIN: Here we have monthly natural gas prices in Southern California, Northern California, as well as the National Index, which is the Henry Hub.

As you can see, we saw natural gas prices go up from a low in January of 2002 of about $2.50, all the way to $5.00 per MmBtu by the end of the year.

The good news we have to report is that natural gas prices in California stayed below the national average. I think that was due to a concerted effort to have a lot of gas in storage, so when the crisis hit and a lot of natural gas was being withdrawn nationally, we had a lot more in line pack, and so were a little bit more prepared, and we didn't see natural gas prices go up as high as they did nationally. So that was one piece of good news in California.

CHAIRMAN WOOD: Do you know what the storage numbers are for 03 for California?

MS. SHEFFRIN: I don't. I know they have been driven down quite a bit, and there will be refilling happening, not only nationally, but also in California. That probably will be what keeps the natural gas prices higher than they normally would be.

COMMISSIONER MASSEY: You mentioned a concerted effort to have storage levels higher. Talk about that.

MS. SHEFFRIN: The CPUC asked the utilities to undertake that action prior to this Winter. They did, and I think it paid off.

MR. HEDERMAN: The Western Area, not just California, but the Western Area Storage is at about 160 Bcf, just below the average for the five-year level. So, relatively speaking, it's better than the others who are all at rock-bottom levels.

CHAIRMAN WOOD: Good.

MS. SHEFFRIN: Next, we just quickly take a look at our ancillary service markets.

(Slide.)

MS. SHEFFRIN: We run markets for regulation-up/regulation-down, spin, non-spin, and replacement, day-ahead, and hour-ahead. What you see here is the costs for 2002 in purple, so we've seen a dramatic reduction in ancillary service costs.

That's mainly been due to an improvement in operating procedures for regulation. When we first started the market, we were carrying quite a bit of regulating reserves. I think the operations people have put into effect, some practices that have allowed us to reduce reserves from an overall 13 percent that includes operating reserves and regulation down to 9.3 percent, so we're very pleased to see that.

At the start of the market, we were holding about seven percent regulating reserves. Now they're down more to the two to three percent, which was sort of the historical practice among the utilities before the ISO took over. So that's a very good thing.

CHAIRMAN WOOD: What is the practice in the parts of California that are not in the Cal ISO control area?

MS. SHEFFRIN: They have to meet WSSC standards and regulate for themselves, so I believe that they are probably more in the two- to three-percent range.

As I said, California is dependent on imports.

This is the import picture for 2002.

(Slide.)

MS. SHEFFRIN: There are both gross imports, gross exports, and then the light yellow bar is net imports. The critical months to take a look at are July and August.

We did have 5,000 megawatts, which was much higher than we had at the height of the crisis, which was more near 3,000 or 2,500 to 3,000, so we actually had a doubling. The rest of the months, we also had healthy hydro imports.

All of that helps improve the competitiveness and performance of our markets.

CHAIRMAN WOOD: When is the hydro in the Northwest at its strongest? Is it late Spring?

MS. SHEFFRIN: Yes, it is late Spring, then everyone gets sort of rock-bottom, bone-dry around October -- September-October.

Take a look at the last market, which is the congestion management market.

(Slide.)

MS. SHEFFRIN: Again, there is good news to report. We have lower total congestion costs in 2002 than we did in 2001.

The major congestion we had was in June and July when we had a de-rate of the California-Oregon transmission line, right at the time when a lot of hydro wanted to come down into California.

CHAIRMAN WOOD: Was that the one related to the fire?

MS. SHEFFRIN: Yes. And so we had higher congestion costs on that. Typically, for the rest of the year, we had dramatically lower congestion costs than we did in 2001.

(Slide.)

MS. SHEFFRIN: The last issue that I did want to point out to you is intrazonal or within the three larger zones that we run, the congestion. We have seen an increase in that, and, in fact, we're probably going to see a much more dramatic increase in 2003.

That is the place where we need the Commission's help. We don't have effective local market power mitigation for these cases.

Every market needs effective local market power mitigation and the ones that we have probably have too high a threshold level. That is the area in which we have filed with the Commission for your help and assistance on, and also for the special circumstance for the Mexican generation, which is really affecting operations.

You're holding a technical conference, but we do ask you -- every market does need local power market mitigation. When you have to have units running in a particular area, and they're all owned by one owner, we need much more than what we have right now. Our thresholds right now are $50 on the incremental side, and negative-$30 on the decremental side, and they are far higher than in any other market, those thresholds. So we would like your assistance in getting more effective local market power mitigation for our market.

(Slide.)

MS. SHEFFRIN: Going forward, the critical issues are local market power mitigation measures that are more effective than we have now, which you already talked about, Mr. Chairman, which is looking at the trend in import bids and seeing if we can do something about that before the summer.

The other is generators declining dispatch instructions. Right now, we don't have a penalty for that. Again, that will come in Phase I-B in October. At least if they decline an instruction, they have to replace the power and a small increment of cost beyond that.

We're hoping those will help, but, again, we'll have to suffer through some of that through the summer, prior to October.

(Slide.)

MS. SHEFFRIN: I'd just like to say that, going forward, we are working very hard to try to fix our markets and put in MDO-2 design. This just lists out some of the things that are a problem -- again, how MDO-2 will address them.

The other critical element is new demand response. I do believe Commissioner Peavey is working hard to try to get some of those new programs in.

We have a test program of 2600 end users, residential and small commercial. I think we still need the time of use rates, the real-time rates for the industrial programs.

Those rates have to be designed and put into effect, and the metering put in. We think those are critical elements.

Thank you very much.

COMMISSIONER BROWNELL: I just want to say, referring to our earlier conversation about kind of what rules changes you need to ensure that there's clear direction and accountability in terms of gaming and other things, that I would hope that that would come in here sooner, rather than later.

In fact, tomorrow would be great. I think we've learned a lot, and I think it's critically important that we all take the steps that are necessary. I would really hope that that would not be dependent on any other aspect of the market design, but we would get that in place quickly.

MS. SHEFFRIN: Thank you. I'll take that message back.

COMMISSIONER BROWNELL: Let us know when we might expect that. That would be great.

COMMISSIONER MASSEY: Following up on that, this point you make about generators frequently declining dispatch instructions, what flexibility do generators have to decline dispatch instructions?

MS. SHEFFRIN: A lot of flexibility. There really isn't any consequence right now for them not listening to a dispatch instruction.

COMMISSIONER MASSEY: Is there a proposal to correct that? Is that before us?

MS. SHEFFRIN: You've given us some help in that in terms of there will be a cost consequence, but also, I think, in the oversight and investigation filing that we'll make, it will be more onerous than just a price.

MR. LARCAMP: Is this reliability dispatch or economic dispatch?

MS. SHEFFRIN: I believe these are reliability dispatch. Thank you.

(Pause.)

CHAIRMAN WOOD: How does that plan jibe with this last issue, the issue of dispatch?

MS. SHEFFRIN: People are required to must-offer, if they haven't already scheduled their unit in some other transaction, and they are up and haven't told us that they're down.

And then if we dispatch them and, for whatever reason, they do not respond, there really isn't a cost consequence beyond just making up in the imbalance market for them right now.

The operators, I think, become concerned about that, and I guess the level of dispatch instruction declines, but has been increasing quite a bit. I think it's up to 15 to 20 percent of dispatch instructions.

So it's a trend that we want to watch, and certainly if it is going to impinge on reliability, the Commission has taken one step to help us in that.

MR. LARCAMP: But that doesn't implement until?

MS. SHEFFRIN: October. The other is, of course, in the oversight investigation where it will have a consequence for declining the instructions from the operator.

CHAIRMAN WOOD: Is that a forthcoming filing?

MS. SHEFFRIN: Yes, it is. It's the one that Commissioner Brownell said should be tomorrow, if possible.

CHAIRMAN WOOD: Okay, thank you.

MR. ETHIER: Good morning. Thank you for the opportunity to present our state-of-the-markets report. This report will be published on our website within the next month, so you're getting a preview today of what happened, what you will see in a month.

On slide 2, there's sort of a brief overview of the presentation.

(Slide.)

MR. ETHIER: I just wanted to note that while I have a very long slide presentation, I only intend to cover the first section, which is market overview, and the last section, which is 2003 market developments. I'm more than happy to talk about all the slides in between, but I thought it would be better to focus on the high-level stuff of what happened in 2002, and, frankly, cheat a little bit and talk about our SMD implementation, which just occurred on March 1, which we're all very excited about in New England, and use that as sort of our discussion launching us into the Summer of 2003 look-ahead.

But as I said, I'm more than happy to talk about any of the slides in between, which have, clearly, a lot more detail than we have time to go into today.

(Slide.)

MR. ETHIER: On Slide 3, the first table that we have is the New England All-In Energy Price. That All-In Energy Price has decreased consistently over the last three years of the market. This is due to a couple of things:

Fuel prices clearly drive this to a great degree, and, the other is, we've had a great deal of new efficient entry that's displaced older, less efficient ones. I would point out a couple of specific lines there.

The ancillary line has increased slightly in 2002, versus the previous years. That's due in part, at least, to revised rules that we implemented last May to pay opportunity costs more consistently to units providing operating reserves, which we believe was a good market enhancement, but it resulted in higher prices in those markets, which was consistent with the rule change.

The capacity line, the final line there, shows that the cost of capacity on a per-megawatt basis has consistently fallen in New England over three years. That, again, is consistent with our system conditions with lots of new entry, and, frankly, having relatively robust system rider reserve margins. You would expect the price of capacity to fall and the resulting costs on a per-megawatt basis, to fall.

(Slide.)

MR. ETHIER: Slide 4 shows -- it tracks our energy clearing price and fuel prices. Every time I present this, I find this is one that sort of resonates with folks.

What it shows is that in the vast majority of days, ECPs roughly correlate to the underlying fuel prices in New England. Primarily gas and oil are important there, and that you see the clusters of green triangles that are well above and typically in the summer months, but a little bit in the winter months.

Those correspond to times of relative scarcity on the system. So during an OP-4 day, which is a system emergency day, you're going to march up the offer stack and you're going to call relatively expensive units, which sort of breaks the direct connection that you have. That's also sort of what you would expect.

Tying into an earlier comment I heard, asking how the gas price changes have affected things, and specifically the gas price increases we saw at the end of February and early March this year, in New England, we had a slightly different dynamic than Anjali pointed out.

We had a couple of things going on in New England that maybe were different than in California and other areas. A lot of units buy inter-day gas as opposed to day-ahead gas, and the only reliable quotes you can really get are for day ahead gas prices, so all this modeling is done using day ahead gas. The inter-day gas premium skyrocketed from 5 or 10 percent roughly speaking on a typical day to, we heard reports of well over 100 percent premium for inter-day gas versus gas that you agreed to buy in the day ahead timeframe.

That sort of complicates the analysis of the prices during that time period. The numbers that we used to model costs are not necessarily the costs that were truly faced by the generators in those circumstances.

The other one that we ran into, which is also problematic to deal with, is in New England, we ran into some curtailment of gas for specific units. There are places on the gas distribution system where on very high load days -- and there's a specific word for it that's escaping me now or phrase -- but basically, they're a lower priority than residential customers, which is almost certainly appropriate. But they get their gas curtailed, and they're not able to offer into the system. So what might otherwise be economic generation is not available on these days, and so again, you get this disconnect between what you model or anticipate and the real world results.

And that's just something that, just to sort of look ahead to the discussion of SMD, it really complicated our analysis of the initial couple of weeks of SMD go live, because the correspondence between the high gas prices and implementing SMD was one to one. It happened at the exact same time, which was sort of the excitement we really didn't want when SMD went live. But that's what we had to deal with. You'll see that in the data I present for that later on.

(Slide.)

The next slide, we also calculate a benchmark, a competitive benchmark in New England, which is comparing the estimated costs of each unit, stacking those up, crossing demand and comparing that to two things. We compare it to the energy clearing price in New England, and we also compare it till we run through the exact same model the offers that are submitted and compare that to the estimated offers run through the same model. That allows you to sort of separate out some of the operational constraints that may be driving the benchmark relative to the energy clearing price.

The numbers that we have are very consistent with the numbers we've gotten in the past, between 6 and 11 percent for the markup in 2002, which in our view is consistent with the operation of a competitive market. My view is there's a relatively large range of error in this kind of modeling, and we're probably inside that range of error with these numbers.

(Slide.)

The next slide, Slide 6, Net Revenue Calculation, which we also did, I think one thing that's important to point out, we did a very similar modeling to Anjali, that is, using sort of a hypothetical new combined cycle and a hypothetical new CT, running at the daily gas cost, and some estimated VOM matter and compared that to the energy clearing price in each hour and add up the net revenues you would get there.

So that part's very similar. I think the biggest difference is the fixed costs that we assume are higher than the ones that Anjali noted, specifically for combined cycle, were in excess of $100,000 a megawatt for a CT, were in the $60,000 to $80,000 a megawatt range. That's somewhat higher than the numbers Anjali used, and at least in New England, those are consistent with the numbers we've gotten and evaluated from a variety of sources.

The important thing to note there is a range there. There's no one number. It depends on where you build, who's building it, what features you have and all that. So there's always going to be some sort of range.

The important thing to note is that when you add up energy revenues, estimated capacity revenues and probably accrued estimate of ancillary service revenues, both the CC and the CT were well below their fixed costs on an annual basis. The CC was $16,000 below, and the CT was $30,000 below.

I guess the next question is, is this alarming? on a poolwide basis, it's not alarming, because it's consistent with our capacity situation. We have, as you'll see later, forecasts of a 30 percent reserve margin for this coming summer. New England has a relatively robust capacity situation right now. I think the problem, though, that exists with looking at these numbers on a poolwide basis is they ignore subareas that have critical problems that are not identified with a regionwide capacity market, like Southwest Connecticut, for example, does need new investment of some sort, either transmission generation, demand response, and these numbers clearly are one reason why we're not getting that investment right now, and we're actively working to improve our markets to send those locational signals.

SMD is a big step in that direction. Our SMD is a big step in that direction because it sends locational energy signals, something we have on the drawing boards, and you recently reinforced for us on Friday, is that we need to move towards locational ICAP, which would more strongly send that signal. In those circumstances, it would make sense to probably break this calculation out on a more subarea specific basis.

COMMISSIONER MASSEY: Let me ask you a question. In the debate over standard market design, we get a lot of pushback from some regions on locational marginal pricing. You seem to be arguing, however, that for your region, it's going to be a very good thing. Can you talk more about that? Is it because it sends such a good price signal for the region? It seems like if it sends the right kind of price signal, new generation comes in or new transmission is built, whatever, that that is ultimately very, very good for consumers.

MR. ETHIER: I agree.

COMMISSIONER MASSEY: Well, you're supposed to.

(Laughter.)

MR. ETHIER: I got that right at least. I think our region is really a case study in the bad incentives of a single clearing price market. We had a single clearing price, a single ICAP market. There was really no locational incentive in our markets. As a result, we got lots of generation where it was cheap to build. Unfortunately, that's not where we needed lots of generation. As a result, we now have bottled generation in Maine and, loosely speaking, Southeast Massachusetts, Rhode Island are areas that have been identified as we have more generation than we can use and export to the rest of New England.

Clearly, if you're going to invest money or incent people to invest money, you don't want that to happen. You want it to be invested in Southwest Connecticut or Boston where you really need it. Our old single clearing price system didn't send those signals, and we sort of saw the results very clearly moving to SMD. Arguably, SMD has already had an effect and it's only been in place two months.

The reason I think that is because if you look in the Boston area, we've gotten either on line or projected in the next month or so about 1,600 megawatts of new generation, new efficient combined cycle is being built in the Boston area, which is an identified load pocket. And we've had significant transmission upgrades by the local TO. Both of those things were in my view at least, strongly encouraged by SMD being on the horizon, by locational pricing being on the horizon.

So those investment decisions, when people saw potential high prices coming down the pike, literally down the pike, they reacted to that. To me, SMD has already had an effect on the distribution of investment in New England, and sort of starting to undo a bit of the bad stuff we had before.

I think the next real test is going to be Southwest Connecticut, to see if we get some movement there. I know the local TO is trying really hard to make some investments and so forth. It's just a question of can we get that thing -- that situation solved and get some investment to solve the problem down there?

I think we're an excellent example of how locational pricing and locational signals -- and don't discount the importance of localizing out-of-market costs as well, which our other market did not do; it socialized them. The out-of-market costs for running generation to support the transmission systems that are sort of unfortunately hidden from the market clearing price sometimes. Sending those to the local regionals has a very important role to play in incenting this investment.

COMMISSIONER MASSEY: Thank you.

MR. LARCAMP: Could I interpret that to mean from a longer term perspective, good local price signals is part of the solution to localized market power because you get the right price, which is in a sense the new generation which decreases the market power over time?

MR. ETHIER: I certainly think, at least the way the markets are currently designed, that's the only way you can expect to work your way out of it. This is something we explicitly tried to recognize in our SMD filing. You have to control local market power. There's no disagreement there.

You also have to realize there are these longer-term market issues that you have to address somehow. There are a variety of ways you can address those, some of them more easily implemented than others. But you clearly have to have that long-term picture in mind when you craft your local mitigation measures.

I'd like to skip to Slide 29.

(Slide.)

It's kind of a big jump I realize. What you'll see when this slide comes up -- I'll cover this really quickly, but I think it's a very striking piece of data from our markets that operated last year. Gas prices have been very much an issue in New England because we're a fairly heavily gas-dependent system and becoming more so, because basically all the new generation is gas.

What this pie chart shows you is it sort of sums up the five-minute intervals in which a particular type of unit was the marginal unit that is setting the clearing price. In New England in 2002, natural gas-fired generation was on the margin 55 percent of the time, which is overwhelming. If you roll in a chunk of the oil gas-fired generation, you're probably around 60 percent, which is a huge amount of time for one fuel to be on the margin.

So New England prices are very dramatically affected by changes in gas prices. I expect that when we do this review again in a year, we'll see significant price increases in New England due to the underlying gas price increases that are going to be directly funneled through our wholesale markets.

What that does to me is say, I need to pay close attention to the gas market, and we need to be alert to what's happening in that market, follow it quite closely, and be prepared to highlight any problems, especially if the number of curtailments starts to increase or if we have other problems, disruptions of gas supply could be very problematic in New England.

COMMISSIONER MASSEY: Let me ask you. What do you see your role being in terms of monitoring the gas market?

MR. ETHIER: I certainly don't envision that I'm going to have a gas division or anything like that. One thing that I did do fairly quickly was talk to our OMOI contact to try to use some of the knowledge that you all have monitoring gas markets, because I know you do that daily.

We also have a couple of people in our planning group that I sort of drafted to help me in this process, to help me evaluate the gas market. We also subscribe to a couple of publications that sort of inform us of trends in the gas market. But I think our role is to stay abreast of it, to be sensitive to maybe not the minute-to-minute fluctuations, but the sort of dynamics of the gas market and so forth.

But I don't know that it's realistic to expect us to do serious investigation or anything like that into the gas market. We clearly have to stay abreast of it and talk to the experts who do do that in-depth evaluation.

Moving on to the next slide.

(Slide.)

Which is sort of where I'm cheating a little bit and talking about 2003. The big news in New England frankly is something we've been working towards for the last two years or longer actually, and I know you all are well aware of this, is implementing our version of Standard Market Design.

It's hard to overstate the sea change that took place in New England when we changed the markets. We basically threw out all of our old software and rules and implemented entirely new software and rules in one fell swoop, literally in one 15-minute interval. The control room went from one set of dispatch software and screens to a brand new set of dispatch software and screens.

I would be doing a disservice to all the people in New England who have worked on this for so long to leave it at that. This is really a long, somewhat painful process both on the ISO's part and the stakeholders' part to craft revised rules, to get up to speed, to develop the software, to be trained.

The training is critical. All these things sort of culminated on March 1st when we moved over to markets which are much more consistent with PJM and New York's markets. So we now have a day ahead market and a real time market, which should have some very positive incentives for generation availability among other things. We now have an LMP system instead of a single clearing price in New England. What sort of got ignored in the transition, basically on the same day we implemented a new ICAP market and a new FTR market, which are very significant, and we immediately allowed virtual trading in our day ahead markets.

So these are things that have been phased in gradually in other ISOs. We sort of did it, you know, it started going 60 miles an hour. We did stuff immediately. I think the good news is the transition has gone probably better than we could have hoped, knock on wood. We haven't hit the summer yet. But, you know, the bottom line is, we feel this is a successful transition, and I think our stakeholders feel that it's been a successful transition.

COMMISSIONER MASSEY: Did you design your own software for this?

MR. ETHIER: It was a combination I would say. Clearly our core dispatch software, we have a vendor that provided that to us, and that's essentially the same as what's used in PJM. We've enhanced it to add some functionality to deal with our region. Specifically, we feel that we have a higher proportion of hydro resources that need a different way of dispatch than PJM had. That was a big enhancement. But the core market software has sort of been vetted in PJM.

I think a lot of our interfaces are substantially modified from what they utilized, and I know our settlement software, which is hugely complicated, is entirely from scratch. So it's sort of a mix of taking sort of the core dispatch software from them, enhancing it somewhat to fit our market and our system, then adding some different interfaces and a new settlement system.

COMMISSIONER MASSEY: How do the hydropower resources appear to be doing in an LMP environment?

MR. ETHIER: In New England it seems to be working out fine. I certainly wouldn't claim that our hydro resources are the same proportion as in California, for example. But we have pump storage units which are incredibly flexible. They're sort of superhydro resources, if you will, and they operate just fine in our new LMP environment.

So far, it's gone basically the way we anticipated it going. The enhancements that I talked about were basically ways to facilitate improved dispatch with the limited energy characteristics of these hydro resources, better optimization of the utilization of the water throughout the day basically. It was all aimed at providing the resource owners with a bit more flexibility with how they get their resource dispatched well, recognizing all the constraints those resources face.

COMMISSIONER BROWNELL: Tell us what you would advise other ISOs. We hear a lot. We need to go slow. We need to take our time. We don't want to be victimized by unintended consequences.

You sound like you went through a really solid planning process up front and I am assuming made the decision to kind of go live all at once because of the integrated nature of all the pieces.

MR. ETHIER: That's right; it made sense to do it all at once. There were a number of factors that helped us have a successful launch: One is, we treated it as a big software project, because that's what it was.

It was planned like a software project, and it had milestones like a software project, and sort of everything fit into this big plan. Frankly, I think the plan, in retrospect, turned out to be a good one.

You know, you can't always adhere to your plan as well as you would like, but we managed to adhere to it pretty effectively, so that was good. It helped that we were getting the market design from PJM in two ways:

One is, we had the sort of proven dispatch software. The other way was that by getting a wholesale import of a set of rules, it really helps. You get something in place.

If you try to build from the ground up, a whole set of rules, it's very time-consuming. Stakeholders, understandably, have a lot of different ideas about how these rules ought to go, and to fight each one out or discuss each one in detail, is really time-consuming.

We were able to import a set of rules, sort of in one fell swoop, and because it was tied to the software, there was sort of a package, and that packaging helped.

I think another thing that helped was that we had extensive testing. We had five sets of market trials, and when I say "market trials," it wasn't just sort of make sure the software runs; we had the participants submitting offers every day, we had scripts on how the generators behaved, we had outages, we simulated basically every possible system condition.

We did this five times for between four days and six days, I believe, each time, where we were running around the clock, dispatching the software. It's really dramatic if you look at the data.

The number of problems we found in the first one was relatively high and by the end, it was a very small number of problems that we were identifying, so that was a very effective implementation tool to ferret out problems, both on our end, I think, and on the participants'.

I think the final one is that we benefitted because we have been running markets for three-plus years now, and that experience is hard to duplicate.

Everybody who was around for the first go-live, said this one went much more smoothly. Part of it was the planning, but a lot of it was clearly the experience we had gained from having done a lot of this before. That might be the hardest single part to transport to another area; that's trying to implement markets for the first time.

California, for example, will benefit from having operated markets when they do their big cut-over, but it's hard to overestimate how important that was.

COMMISSIONER BROWNELL: We hope you're going to be sharing your experience with the other developing ISOs and RTOs. Why did you decide to build a settlement system from the ground up?

One of the things we've talked about and we're worried about is cost. We've committed that we're going to be more involved in looking at those costs. Why have to build it from ground zero? Is it exportable anywhere else?

MR. ETHIER: I have to be a little careful on this ground, because this is my area of expertise, but at a high level, my impression is that available settlement systems that would work with the day-ahead and real-time market virtual bids, all these things, PJM has one, but it's a mix of new and old; it's sort of a legacy system.

And it really didn't lend itself to sort of plug-and-play. Our old system, it was more costly to adapt it than to write it from scratch, so I think that's why that decision was made.

As far as, is it exportable, certainly I think a chunk of it, I would hope would be, because my take on it is that it's one of the first settlement systems that was sort of written specifically around this from the ground up, around this type of market design.

PJM sort of fixed what they needed to fix, which probably made sense for them as they went along, as they implemented new features, because we were sort of going with the big bang. We didn't have that luxury to sort of add and modify, but because we did that I would hope that it would be exportable to other areas.

COMMISSIONER BROWNELL: One more question relative to something that Dr. Sheffrin talked about. Are you experiencing the same problem with generators ignoring dispatch orders?

MR. ETHIER: No, we haven't had a problem with that. A part of it is because we have a day-ahead market which really incented folks to live up to their day-ahead commitments. They have a real financial incentive, and that's one of the big advantages. Anjoli doesn't have the luxury of having one anymore.

And the other one is that we do have penalties and sanctions. If you willfully ignore dispatch orders for non-physical reasons, that is, if you don't have an outage or something like that, there are penalties that can be applied, so there are a couple of things that I think work in our favor that she may not have the benefit of.

COMMISSIONER BROWNELL: We hope you'll send the rules to her.

MS. SHEFFRIN: We talk all the time.

COMMISSIONER MASSEY: So the penalty provisions are in your tariffs?

MR. ETHIER: They are, and they've been there since the start of our original markets in May of '99.

COMMISSIONER MASSEY: Let me ask you this: Why have you had so much generator entry in your market?

MR. ETHIER: I answered this question last year as well. I need to be maybe a little more careful about how I answer it this year.

(Laughter.)

MR. ETHIER: A lot of those decisions were frankly made before the markets even went live. There was a lot of enthusiasm for the new markets. The industry as a whole sort of had this attitude that, you know, you need to get in now because these markets are where you want play and so forth.

Those decisions were made five years ago, and we're still getting the entry based on those decisions. The flip side is, we don't really have much in the pipeline after this year. Most of it is all going to be in by this year with the long lead times to construct and decide and all of that.

So we really benefitted from that enthusiasm. And some of it is certainly warranted. New England had an aging fleet of relatively high-cost, oil-fired resources. Natural gas, at the time, at least, was very attractive. The resources were clean, efficient, lots of good things.

And we're clearly benefitting from that investment, but it was one of these -- the industry goes in cycles, and we sort of are in this sort of overbuild cycle, if you will. I just hope that we can avoid the trough on the other side.

Slide 31, please.

(Slide.)

MR. ETHIER: As I mentioned, the markets have worked well. The one sort of -- the biggest blip from a market clearing perspective is, we had some congestion in Maine, especially in the first few days of the market, that resulted in very high nodal prices in a small area of Maine.

That was associated with virtual trading in the day-ahead market, associated with things called sellers choice contracts. We immediately contacted the participants involved in this, and we've taken the approach that we need to facilitate them sorting this out.

It wasn't nefarious behavior, in our view; it was sort of the logical result of folks trying to fulfill these contracts on basically a weak portion of the transmission system.

That activity has gone way down. We're still not quite out of the woods yet, but certainly the price levels and the congestion that's created, has gone way down in the day-ahead market. I think we have a little cleaning up to do, but I think our approach is sort of a sound one.

We didn't want to jeopardize the functionality of virtual trading, because we think that's important, but we did need to get this cleaned up, and by working with our participants and sort of explaining the problem, they have been able to sort of change these contracts. They have less of an incentive to do this.

(Slide.)

MR. ETHIER: Slide 32, the next slide, just says, look, our new markets have experienced a lot of different system conditions and they have performed well, and, importantly, reliability has been maintained, we have met our reliability standards in our new markets.

(Slide.)

MR. ETHIER: Slide 33 is an interesting one. This is sort of the market results from our new markets. It shows the day-ahead and real-time prices from March 1 when we cut over, to early this week or late last week. You can see those prices come off very dramatically as gas prices have come down.

That's what you would hope to see. I think that one of the most interesting things is our day-ahead versus real-time average price spread has been quite tight. It's been about $1.25 over the first two months, which is sort of remarkable convergence between the day-ahead and real-time market, and I don't expect that we'll sustain that every day.

But, to me, what it suggests is that we're getting players who have learned from other markets with day-ahead and real-time markets, and are taking what they have learned elsewhere and applying it to us, and how to appropriately offer into the day-ahead and real-time, and how to arbitrage those price differences, which is what you want to see.

CHAIRMAN WOOD: What percentage of the energy ultimately consumed by the customer, is purchased through the real-time market and the day-ahead market, and then the bilateral market? Those would be the three buckets.

MR. ETHIER: The third bucket, I would have a hard time giving a firm number for, because it varies. I would say it's in the 60-70 percent range, contracts that we are aware of.

There are likely contracts that we don't necessarily have sort of good visibility of, but at least 60 to 70 percent is almost certainly contracted under relatively long-term arrangements, be it a month, a year, or five years.

COMMISSIONER MASSEY: Would that include self-schedule?

MR. ETHIER: Oftentimes those contracts do sort of materialize via self-schedules, yes, but the first two buckets, sort of treating those as a whole, are actually addressed in the lower left-hand corner of this figure.

There are two numbers there. One is the day-ahead pool-cleared generation, which is basically what amount of generation that you ned in real-time, is actually committed in the day-ahead market, and it's about 93 percent, which is a pretty healthy number. That means a lot of generators are firm, day-ahead, which, from my point of view, is probably a good thing.

While I don't have a specific target in mind, you like to hear the day-ahead target be pretty robust, and I think we're seeing that. The lower number, which is probably more to your question about how much load is sort of hedged to the day-ahead market, we're seeing about 97 percent of load.

That is calculated by adding up fixed demand bids, price-sensitive demand bids, and virtual-demand bids. Adding those three, we're clearing about 97 percent of expected real-time demand in the day-ahead market.

Our day-ahead market is clearly transacting the vast majority of the business for our spot markets, and it's happened relatively quickly, which is sort of why I think folks have learned from other markets, and taken that learning and applied it to us, which is why it's sort of reached these relatively high levels pretty quickly.

(Slide.)

MR. ETHIER: On the next slide, which is Slide 34 -- -- and I'm nearly finished here -- just to show you, what I would like to point out on this slide is basically the little yellow bars that show the congestion costs. They have been very, very low since we've started the markets on March 1. We have had very little congestion in New England since March 1. Unfortunately, I can't say it's the magic of SMD that's caused that, although I wish it were the case.

But it's due to a couple of things: One is that in New England, something that was sort of an eye-opener for a lot of folks is congestion is really fuel-price-dependent.

In our typically congested area, we have lots of oil-fired generation, and during March when oil looked good relative to natural gas, we were actually exporting at times from Connecticut to the rest of the pool, because the oil-fired generation looked relatively good compared to the natural gas-fired generation.

That's one of the things that's reduced the congestion. Another one has been, you know, we've gotten transmission upgrades, certainly in the Boston area. The other thing is, we've just had relatively low load levels. The system hasn't been highly stressed since March 1, because loads have been relatively modest.

Unfortunately, I don't think this lack of congestion will continue through the summer, but that's what we have experienced so far.

(Slide.)

MR. ETHIER: And then going on to Slide 36, as I noted, we have relatively high reserve margins forecast for the near term, due to lots of new generation coming online. This is not really an attempt to forecast any retirements, to the extent we have retirements. It could change those numbers.

(Slide.)

MR. ETHIER: Slide 37 is demand response. I think the good news there is that we've gotten -- going into the summer, we have almost 300 megawatts of demand response, which is about 50 percent more than we had last summer, which is very good news.

We've certainly added some folks to focus on that more heavily, and I think the results show here. I think the area of concern with demand response is, last summer, even though we had megawatts signed up, we got poor performance.

We had less than ten percent of the available megawatts to respond in a given event that actually responded, and we're actively working on ways to boost that number, and we have some leads on why that may be the case, but that's a real concern. I don't want to be in the case of having phantom demand-response megawatts that don't really show up when you need them.

COMMISSIONER BROWNELL: What's your assessment? You said you had some leads about why that may have happened. Give us some thoughts.

MR. ETHIER: There are a couple of things that our demand-response folks are focusing on. One, just because a company signs up, it doesn't mean the company itself has good communications about how to frankly respond.

Well, the folks signing up may understand what it may take, but there may not be good internal communications to effect that response when an event happens.

So, we're working on that to make sure the companies really understand how the programs work, how, internally, they need to respond, et cetera.

The other one is perhaps even more basic. Even though we send out e-mails, do phone calls, and post it on our website, it's unclear if folks are really getting the message that it's a demand-response event.

Those are things that clearly we, as the ISO, can work to improve. Those are some of the initial steps we are taking.

I know that there's still some discussion between the Commission and the ISO about how the programs looks for the summer of 2003. I think the hope is that that will improve under the response, as well, but I think that things we can clearly act on are those two issues.

This is different than the experience New York has had. I know they will be here in two weeks' time. They've gotten a much better response, and I hope that we can get a lot closer to that, because nine-percent response is really a potential issue.

(Slide.)

MR. ETHIER: The final slide on Areas of Interest, real quickly, for this summer, SMD burn-in, that is, we haven't really hit OP-4 days yet with SMD. Let's hope that it operates as well then as it has been so far.

Southwest Connecticut is still in sort of a delicate reliability situation. The local CLMP has made some important upgrades for the summer, and that's helpful, but you never know. If we had one big contingency, we have some big units down there that if they're not available, that could be a problem.

The demand response, we've already talked about, and then now that we've gotten SMD go live behind us, we still have this whole backlog of market improvements we need to work on throughout 2003 that are, I think, going to be very important for the long run, affecting the rest of our market.

COMMISSIONER BROWNELL: So, with the new market design and the appropriate price signals, Southwest Connecticut, I guess, kind of understands the price of choices. Is the issue basically that they don't want siting? Does that continue to be the issue?

MR. ETHIER: There is a lot of discussion about the siting. Progress has been made. There's a chunk of the transmission line that's being proposed. They have agreed on siting that chunk.

The way they have done it is to have some of it above ground and some of it underground. Now the discussion is over who pays to put it underground, versus to have it above ground?

My hope is that the next chunk of it, which will be the final chunk, will sort of proceed in the same way. I think everybody recognizes it needs to go through a similar corridor. It's just a matter of how do you build it in a way that has impact that's acceptable to the local communities?

But we've seen some progress. Personally, I think SMD helps in that regard, because of the price signals that you just mentioned. It makes people realize that this is something that is in their interest to address.

I'm hopeful we're going to continue to make progress down there.

COMMISSIONER BROWNELL: Thanks.

CHAIRMAN WOOD: Bob, on the pages you skipped over --

COMMISSIONER BROWNELL: Nice try.

(Laughter.)

CHAIRMAN WOOD: On page 12 -- it's actually after 11 and below 13 -- it looks like this energy market -- one of the issues that we were talking about in my visit after you all cut over to the SMD and since I've been to New York on the seams issues between the two ISOs today, is this rate pancaking issue.

I'm looking at kind of the imports to New York and to New England. It looks like it's kind of trended.

MR. ETHIER: We've become a net export, yes.

CHAIRMAN WOOD: Which makes sense with your large capacity market. The first question: What is the physical capacity between the two regions?

MR. ETHIER: The nominal is just in excess of a thousand megawatts. I think that in practice, it's more like 900, because there are some loop flow constraints that in certain hours bind and so forth, but a rule of thumb would be just south of a thousand megawatts.

CHAIRMAN WOOD: Is it pretty full all the time?

MR. ETHIER: No, it's not. David is smiling next to me because this is one of David's areas of interest, and with good reason. It's not full all the time. That's something.

One of the things I had on my areas to watch is the seams reduction is really important. Pancaking is an issue. Clearly, there are lots of times when arbitrage could happen, but for the costs that you pay to export and import into a control area. Another one is the lead times.

As long as we have lead times in excess of five minutes, say, just to toss a number out, to transmit a transaction across a control area, you're never going to be able to have a really good forecast of whether you ought to be importing or exporting in the next hour, because the prices change relatively fluidly on the interface.

As long as we have significant lead times, I think you're always going to have barriers to efficient arbitrage and fully utilizing those lines.

CHAIRMAN WOOD: And the lead time, by that you mean the actual schedule that's required to go outside the region?

MR. ETHIER: Exactly. And there are some discussions, internal to both New York and to New England about ways to improve that, either via the ISOs taking a more active role, or how to facilitate the participants being able to do that.

Those discussions are ongoing at this point.

CHAIRMAN WOOD: That's good to hear. Three pages later, it's a lot like the one that Anjoli did. I'm trying to understand what this is telling me. It's a little different than Anjoli had, but I think it's a similar point.

What conclusions do you draw from the data, particularly in the first two numerical columns on page 15?

MR. ETHIER: I think this table is important because it shows that during large chunks of the year, excluding the summer, essentially, the market doesn't have a pivotal supplier in the vast majority of hours. That is, there is no one entity that is required.

Some of their capacity is required to meet system load plus reserves, so that's a positive competitive situation. Part of that is because it's reflected on a page earlier. We had the HHIs, which are quite low, so we really only have one sort of big competitor, and by the standards of other control areas, they're not even that big, so that's a very good thing.

But what it does show is that this is a very fluid situation. With the high loads you see in the summertime in July and August, there are a lot hours where the supplier is pivotal, and there's the potential that they could seek to take advantage of that situation.

What this says to me is that at the very least, we need to do our very best to know what's going on in those hours. Actually, New England stakeholders will be discussing on Friday at our participants committee meeting, a proposal by the ISO to submit a filing to you all that says, look, let's construct some market power mitigation measures that are targeted at these pivotal suppliers in these pivotal hours, because there are real concerns that they have the ability, if they were to withhold generation, they could significantly influence the market outcomes.

The proposal is targeted specifically around the hours that are identified in this table.

CHAIRMAN WOOD: On mitigation, is it also your recommendation that this would be in response to our invitation, if there were actual problems, to remedy? That's what this related to?

MR. ETHIER: Exactly.

CHAIRMAN WOOD: What are the third and fourth numerical columns?

MR. ETHIER: Those are basically saying, over the course of the whole month, what's the average RSI? I think the importance of those two columns, the first one, the average RSI, the importance of that shows that the situation changes, hour by hour.

Just because you have a problem at 3:00 on a really hot day, doesn't mean you have a problem at 2:00 a.m. on another day of that month.

CHAIRMAN WOOD: The average for the month are a little above your trigger point.

MR. ETHIER: Exactly. A typical hour, if you just look at a random hour, you're likely not to have a problem. It's really this narrow subset of hours that we have concerns about.

And what the third column shows is sort of the for the worst hour each month, what is the RSI. Anjoli was using a trigger of 110 percent, I believe, where anything below 110 percent sort of raised flags.

As you can see, the worst hours in July and August were far, far below 110 percent, where the largest supplier, a substantial chunk of the largest supplier's capacity was required to meet load and reserves, which is of concern.

That's why we are actively putting forth these rules in the stakeholder process in New England.

CHAIRMAN WOOD: This shows that when somebody actually had the potential to assert market power.

MR. ETHIER: Yes.

CHAIRMAN WOOD: Do you all look at whether they actually did so?

MR. ETHIER: Yes, we did. I think the difference for 2002 versus 2003, at least with our current state of the market rules, is that we had market power mitigation measures in place that could handle this situation.

Those sort of rules of the road were pretty well known, and they could have been triggered if they attempted to exercise their dominant position in the marketplace.

They were not triggered, and it's tough to separate, did they not trigger them because they knew they were there, or did they just choose not to or what have you? But, at any rate, we had mechanisms to deal with it in our old marketplace and we don't in the current marketplace.

CHAIRMAN WOOD: And you said you all would be coming in with something?

MR. ETHIER: We anticipate that soon.

CHAIRMAN WOOD: Okay. Is that really the only place where you've got kind of a hole in the garment, is on these particular issues that are raised on this slide?

MR. ETHIER: At this point, yes. I feel that's sort of the one area we're actually trying to bolster at this point, and after a summer's worth of experience with our new markets, we may have developed other areas, but I think at this point, we have a pretty comprehensive local market power mitigation structure, and it's really the general market power mitigation stuff that's sort of in flux.

CHAIRMAN WOOD: On the opposite coast, the opposite happens. Thank you very much. Dr. Patton, welcome back.

MR. PATTON: Thank you. In contrast, you've approved mitigation measures for the Midwest that address essentially both issues, but we have no market yet to mitigate.

(Laughter.)

CHAIRMAN WOOD: So you're in the middle, all right.

MR. PATTON: Just to remedy any confusion about my title here, for anyone who doesn't know, I'm the head of a group that serves as the independent market monitor for the Midwest ISO.

The Commission has taken actually a number of rational steps to ensure that I'm not actually a consultant on behalf of the Midwest ISO, that independence is maintained.

This is the first time I've presented on the state of a market that doesn't yet exist, and it's a very liberating thing.

(Laughter.)

MR. PATTON: Although what it results in is a report that will look very different than the other state-of-the-market reports.

The full report and presentation will be posted on the Midwest ISO website. It covers the characteristics of the Midwest markets. In general, it look at the wholesale market prices in 2002 from the bilateral markets. It does an assessment of the utilization of transmission.

The one thing the Midwest ISO is doing or the primary role they're now serving and have been since February, is as the transmission provider for the region, selling transmission service.

Part of that is an assessment of how well the current operations, which are essentially a structure under open access, how efficiently the transmission is utilized, relative to an SMD/LMP type structure, which is where the Midwest is headed in early 2004.

It presents the results of a pivotal supplier analysis that I had done to identify local market power that is participants' only option for solving transmission constraints in the Midwest.

It does an assessment of the current state of the market rules and makes recommendations where we feel there are issues that still need to be addressed.

Lastly, it assesses the RTO configuration in the Midwest and the coordination that's going to be necessary between the Midwest ISO and the adjacent RTOs. Only some of those topics am I going to talk about today, in order to make sure I adhere to our time guidelines.

But I think you have seen the full report. We'd be happy to answer questions on any topics that I skip.

(Slide.)

MR. PATTON: Going to the second slide, this is a very general summary of the market characteristics in the Midwest. The fuel mix in the Midwest is notably different than either the Northeast or the West, in that is 60-percent coal. Most of the new generation is natural gas, but it's still only about 16 percent.

Hydro plays a very small role in the Midwest, outside of some very specific areas, so that the price dynamics are significantly different in the Midwest, and would be expected to be, versus other areas, and I'll show you that in a moment.

The price spikes that occurred in the Midwest caused a very large amount of capacity to e installed. That has resulted in reserve margins that are in most areas, between 20 and 30 percent now, so the capacity situation is relatively good in the Midwest.

(Slide.)

MR. PATTON: Going to the next slide, I'm summarizing daily bilateral prices. You can see that the prices in the Midwest have been within expected ranges, the kind of trends we've seen, and because in electricity, there's not an economic storage option, load plays the most important role in pricing, so that you have peak prices significantly above off-peak.

You have summer prices significantly higher than shoulder, but what I have also shown you on this chart is the trends in coal, fuel oil, and natural gas. You can see that in the fall, that prices were higher than in the Spring, largely because of the increase in natural gas and oil prices.

Were I to show you the same chart for New York, or as Bob showed it to you for New England, the price increase would be much more significant, because natural gas and oil set prices in a much smaller percentage of hours in the Midwest, and coal actually has dropped by about ten percent from the beginning of the year to the end of the year.

MR. HEDERMAN: David, I have a quick question about the coal index. Normally, I think a two-percent increase is typical in decreasing coal prices. What is the explanation for such a large drop?

MR. PATTON: To tell you the truth --

MR. HEDERMAN: Efficiency in the units, or this is just pure fuel, right?

MR. PATTON: These are just fuel prices. The coal is an area where the data on spot coal prices is less available than similar data on fuel oil and natural gas, so what this is, is a monthly index. Part of the reason it shows a lot less volatility is, it's a weighted average of contract and spot prices, so it's not going to pick up all the spot fluctuations.

(Slide.)

MR. PATTON: Going to the next chart, what I'm showing you here is the basis of analysis that we've done, looking at how well bilateral prices reveal congestion in the Midwest.

I'm showing you the difference between upstream and downstream prices for a specific flow gate, the Eau Claire-Arpin, which is the primary interface between the Minnesota-Wisconsin, upper Michigan area. It's one of the most constrained interfaces and the highest value interfaces from a congestion standpoint.

The downstream price is the price in the constrained area, and the upstream price is the price outside the constrained area, so you should see that the price is negative on the scale that I'm showing you here, when congestion occurs.

That's certainly the case in an LMP system. What I have also shown you is the days when there were TLR events. There should be then a correlation between when

TLRs occur, signaling congestion, and the price differences between these areas.

What we found -- we did a number of econometric tests to try to determine whether that actually exists. It turns out that that relationship doesn't exist, with the exception of two interfaces, Eau Claire being one, but even on Eau Claire, on the average price difference, upstream to downstream, is only a dollar when congestion is occurring.

The conclusion is that the current bilateral prices don't do a very good job of revealing the presence of congestion and sending accurate price signals to participants.

(Slide.)

MR. PATTON: Going to the next chart, what I'm going to show you for the next few charts relates to the Midwest ISO's activities in selling transmission, which is really what is facilitating the current wholesale market today.

What you can see on this chart is that the quantity of approved reservation requests rose dramatically from the time that the Midwest ISO began operation, to the end of the year, with firm reservation approvals rising about 130 percent, and non-firm rising about 135 percent, which is roughly triple.

Across the entire year, the percent that was approved versus refused, was very high. Part of the reason why the reservation requests and the approvals have risen so dramatically, you can see on the next chart.

(Slide.)

MR. PATTON: This shows the transmission pricing over the year. The Midwest ISO implemented relatively significant discounts for a lot of the transmission service, particularly through-and-out service, which played a big role in increasing the utilization of the transmission system.

The other improvement that I think accounts for a lot of this is improvements in the calculation of flow gate capability, which has improved over time, and there are a number of improvements that continue.

The report -- I'm not going to go over it, but the report also assesses how accurate the AFC postings are in revealing that there is physical capability on key flow gates. What it shows is that there are many hours where there is significant physical capability, but the flow gate, the AFC values, are very close to zero.

That signals, to some extent, data issues, but it is also inherent in how these systems operate. Once a reservation is made, you don't know whether the person who's reserved it is going to schedule, and so you can't post that as being available.

And so it contributes to the underutilization of the system, in general. But there's certainly more on that in the full report.

(Slide.)

MR. PATTON: Going to the next slide -- actually, go ahead and skip that one.

(Slide.)

MR. PATTON: This shows the quantity of TLR events through the year. The Midwest ISO accounts for about two-thirds of the TLRs in the Eastern Interconnection. That shouldn't be too shocking, because a lot of the Eastern Interconnect is operated through LMP markets that don't rely on TLRs, but it is a large quantity, and you can see in the graph that the energy and transactions that are curtailed, track with the TLR events, as you would expect.

The curtailments actually would be higher, but for TLR Level 4, which is a higher level, is a TLR where you're calling on redispatch. Generally that's occurring in Wisconsin, so you don't actually see curtailments associated with TLR-4.

Now because TLRs happen frequently in the Midwest and because they have a significant impact on business in the Midwest, we've done a fair amount of analysis in this report assessing the calls of the TLRs.

(Slide.)

If you go to the next chart, what this pie chart will show you is that TLRs occur in about 14 percent of the hours in 2002. There's a TLR somewhere on the system. What we have looked at here is what the physical flow was on the flowgate that justified the TLR to assess whether the TLR was warranted.

What we found is that in 1.5 percent of the hours during the year, was the flow less than 95 percent of the limit, in only 0.2 percent of the hours was the flow below 90 percent. So it suggested that the operators were calling TLRs when there was relatively clear evidence that the TLR was needed to keep the flow from exceeding the flowgate limit.

Just so you recognize why there's some variation in this, the TLRs are called about half an hour before the hour, and it covers the whole hour, so there's some forecasting and uncertainty associated with whether a flowgate is going to be overloaded. You can't expect these to be perfect.

We also looked at whether the flows exceeded the flowgate limits when TLRs were not called, which is the flip side, and found that that was not the case.

(Slide.)

The next analysis I'm going to show you -- don't look at that table yet. You probably can't read it anyway -- is an assessment of the efficiency of the TLR process in managing congestion. What we're doing here is looking at how many megawatt hours of transactions were curtailed to manage congestion on a flowgate relative to how many megawatt hours you would have had to redispatch if you were running an LMP to manage the same congestion.

CHAIRMAN WOOD: Say that again.

MR. PATTON: The analysis in this minute table I have put on the screen here is showing an analysis where we're comparing the number of megawatt hours of transactions that were curtailed to manage congestion on a given flowgate relative to the number of megawatt hours you would have had to have redispatched were you running an LMP market to manage the same congestion.

So it gets at how clunky the TLR process is or how inefficient it is in managing congestion. What we created was something we call a redispatch ratio, which is shown on this table, which is the percent of the curtailments that you could have avoided had you done redispatch in one of two ways.

The first way is by choosing the generators that have the best impact on the flowgate and redispatching them. The second is taking economics into account and doing an economic redispatch, which is kind of cognizant of how much impact they have on the flowgate, but also is cognizant of how expensive they are to redispatch. What we found is the redispatch ratio ranged from 30 percent on average in the minimum redispatch case to 38 percent.

I've shown you in this table the flowgate-by-flowgate results. What that means is, we essentially curtailed three times as many megawatts through the TLR process as you'd have to redispatch through an LMP market to manage the same congestion. And it indicates why the central dispatch process as the basis for the market makes sense.

COMMISSIONER MASSEY: When that happens, when you curtail three times too much, what impact does that have on market participants?

MR. PATTON: Let me just make sure I clarify. They're not actually curtailing too much. They're not curtailing too many transactions. They're curtailing transactions that are much less effective at reducing the flow than if they optimized which generators to move.

What effect does that have on transactions is it potentially -- business in the Midwest -- it potentially leaves undispatched generation that is economic that has a bigger impact on the constraint, which if that generation was participating in the price-setting process, would send a much more accurate signal on which energy really worked in that area, and you're incurring costs -- I think it's fair to say by definition, you're incurring costs that are significantly higher than if you optimized by choosing the most economic generation. You're turning down generation through the TLR process and replacing it with other generation that's potentially more costly, much more than you would otherwise have to if you were more deliberate and optimal.

COMMISSIONER MASSEY: Is there any public good that this promotes compared to the better option?

MR. PATTON: Not that I can think of. Potentially, you could point to the costs of running an LMP market is an offsetting cost, but it's hard to imagine it's significant in comparison to the efficiency impacts.

Okay. That was probably the good news for where we're headed. I'll give you the tenuous news. I'm going to now show you an analysis that is similar to an analysis I presented here last summer.

(Slide.)

The configuration, the electrical interactions between the Midwest ISO and adjacent markets. What has changed since the prior analysis is that Illinois Power has indicated a preference to join the Midwest ISO and the SPP Midwest ISO merger has terminated, which affects this analysis.

What I'm showing you in this chart is what percentage of the generation that has a significant impact on the transmission interfaces in the primary RTO is going to be dispatched by another RTO, and this is flowgate-by-flowgate. I haven't named the flowgates, but I've told you what control areas they're in.

The middle panel on this chart is showing you flowgates that represent the seam between two RTOs, in this case between PJM and Midwest ISO. And for purposes of defining who the primary RTO is, the primary RTO on the left is Midwest ISO. Those are all Midwest ISO flowgates. In the middle where it's a seam, I've defined Midwest ISO as the primary. Then on the right is PJM.

What you can see in this chart is that PJM and the SPP together control roughly I would say on average 40 percent of the generation that has a significant effect on the flowgates in the Midwest ISO that I'm showing you. The situation is somewhat worse in PJM for the flowgates that I've selected. And I selected ones that have some evidence of having been constrained and are relatively closer to the Midwest ISO areas. But there you can see the Midwest ISO would be dispatching 40 to 90 percent of the generation that will impact flowgates in the PJM areas.

And between PJM and MISO, the Midwest ISO controls the majority of the generation that affect those flowgates, but PJM still will control, depending on the flowgate, between 10 and 40 percent of the generation that affects those flowgates. So why is that important?

It's important because it shows a high degree of electrical interaction between the systems, and that if you allow those RTOs to dispatch their systems independent of one another, they're going to be causing congestion on each other's systems that will cause the LMPs in those areas to not be correct. They will be inefficient.

What they will reflect is the cost that that RTO is incurring to try to redispatch to relieve congestion that the other RTO is causing, which may be multiples of the cost of redispatching the generation that's actually causing the congestion. So that's the inefficiency side. You could end up with LMPs that don't make a lot of sense and create a lot of uplift.

On the gaming side, you have a significant problem as well in that generators located in the neighboring RTO can dispatch their generation to cause congestion that then they can schedule wheeled transactions across the primary RTO to apparently relieve, but they won't really be relieving it because there will be a corresponding loopflow caused by their dispatch in the other RTO. I know this sounds strangely reminiscent. It's in fact -- the potential is quite a bit worse than California because of the interaction that these are not just loopflows, they really look a lot like direct flows.

So that's the assessment, and you've heard that assessment before. What we're relying on to address that is the joint and common market provisions that are being developed between PJM and Midwest ISO and the SPP, and we've been tracking and assessing the progress there. What they have I think done a good job on is developing the market/nonmarket interface. And what I mean by that is how to run an LMP system next to a non-LMP system so that when the LMP dispatch causes congestion in the non-LMP area, they can call a TLR that will cause reasonable redispatch in the LMP area. And so there's an extensive set of provisions that have been developed that I think look like they should adequately address all those issues.

What hasn't been developed past the very, very formative stage is the market-to-market interface, what you do when you have two LMP systems operating next to each other, which is what I'm worried about. And I think -- and part of that is just because the market-to-nonmarket interface is a nearer-term issue because the prospects of having that occur look like they are going to happen sooner, and certainly did when we started this process. But I am concerned that the market-to-mark coordination that's going to be needed to make sure that we don't have significant problems in the Midwest are complex and will take quite a bit of time to figure out and write software to implement.

And really, when you need it is when the second RTO is coming into operation. So if MISO began operation in the Midwest in spring of '04, then I think you'd have to look hard at approving PJM operation of an LMP in the AEP commonwealth area until that market-to-market interface was in place or vice versa.

What the report does is actually outline a number of specific recommendations for how that interface may work, what kind of exchange of information on constraints needs to take place, what kind of settlement rules you likely will need between the RTOs, and how the market models in each area will need to recognize transmission facilities and constraints on the neighboring system.

So hopefully it will serve as a starting point for people to consider those ideas and move forward more rapidly.

COMMISSIONER MASSEY: Is this, the solution to this problem is technically feasible, it simply requires a lot of working through to resolve? Is that an accurate statement?

MR. PATTON: Yeah. It requires some. It also requires some philosophical judgment or decisionmaking. I'll just allude quickly to the seams issues between New York and New England. We've made repeatedly recommendations to change how we schedule transactions between the Northeast RTOs so that in the same way that New York dispatches generation and serves load and determines the physical flow on the major interfaces inside of New York, like the Central East interface, it's my belief that the ISO should be determining the physical flows between themselves based on the same set of information, which is the bids of the loads and the offers of the generators and put in place provisions that allow participants to transact financially.

The utilization of the New England/New York tie that is lackluster is largely related to the fact that the physical interchange is determined entirely by participants, and they're not doing a very good job. And in part, they can't do a very good job because they're forecasting 75 minutes ahead of time. There's significant financial risk when they engage in a transaction, and the ISOs actually have the information necessary to determine what the optimal interchange is, but we don't take advantage of that today.

So it requires employing the same philosophy we employ inside the ISOs to the seam between ISOs. Jumping back to the Midwest, the same sort of philosophy I think needs to be applied so that the interchange between PJM and MISO would be determined by the interaction of those markets, not by participants putting in physical schedules.

Because the irregularity of the seam, I think it would take a significant amount of resources just to figure out all the gaming potentials there would be for how they could schedule physically to cause problems between those areas.

You certainly could set up systems to allow them to transact financially, which is what they do within an RTO area.

COMMISSIONER MASSEY: Does that mean that the New York ISO, for example, has to have some sort of access to the bidding data for New England?

MR. PATTON: No. The nice thing about LMP is all the information you need is embedded in the locational prices that you're looking at. So if you have a point that's essentially electrically the same point on the two systems or a series of points and you redispatch in a manner to try to cause those prices to equal each other on a five-minute basis, you will in essence be incorporating all the information about the neighboring market in your dispatch.

It might not be so easy in the Midwest. You might actually have to exchange what we call the shadow price of constraints, which essentially tell you what the cost of managing congestion is on a constraint. So if PJM sends that information to the Midwest ISO, the Midwest ISO dispatch model can say, well, PJM is telling me it costs $40 to manage congestion on this binding constraint. My redispatch I can relieve the flow for $20, so it will redispatch incrementally, because that's efficient relative to redispatching the PJM generation.

So we need to think about what kind of information needs to be exchanged. But my feeling is that the communication technology exists to allow this sort of communication in real time between RTOs to inform their dispatch, because the same sort of communication is necessary when we're communicating with generators or in the Midwest, we're communicating between the control areas in the Midwest ISO.

So it's not, on the practical side, communication side, we're not asking them to do something that is new. But certainly how to incorporate that information into the dispatch model is somewhat new.

CHAIRMAN WOOD: When MISO has the LMP system in place and PJM does as well, what needs to happen that is not from you know anticipated to be happening to resolve this issue?

MR. PATTON: Let me not suggest it's not anticipated to be happening.

CHAIRMAN WOOD: It's not on the game plan for implementing the software and/or protocol and/or rule change or whatever.

MR. PATTON: Let me try to be as clear as possible. There is a joint and common market system or a joint and common market effort, and part of that is related to coordination, which is the part I care about. I care about the other, but it doesn't address this particular problem. Part of it is related to sort of one-stop shopping, making it easier for customers to do business.

With regard to coordination, they clearly recognize this need and they recognize it's a twofold need. There's a market-to-nonmarket need which they've been focused on and have provisions developed for, and there's a market-to-market LMP-to-LMP coordination need. And it's not that I think anyone would disagree that they need to coordinate on it. It's that very little has been done so far to develop specific provisions on how to do this.

And given the difficulty I think in making this work, partly because it's new and it will require software changes on both parts and processes to communicate, my feeling is that we need to accelerate getting the plan down in what we're doing on the market-to-market so that we can start the implementation phase.

And so I think it's just partly I'm concerned about the timing, that it doesn't seem to be moving forward as quickly as perhaps it needs to. And I don't know enough to say whether the substance is a problem, because there's not much substance there now. So I'm trying to put some proposals on the table that may be a starting point for the working groups.

CHAIRMAN WOOD: So I take from that answer that in the game plan for the joint and common market, the issue of harmonizing the jagged configuration seam, what we're talking about here about who dispatches to relieve congestion, is not in the game plan right now to be addressed?

MR. PATTON: Well, it is, but when you look at the steps in the joint and common market, it's not entirely clear when the degree of coordination that I'd like to see is going to take place, which phase it's in, and where if there's any disconnect between the folks working on joint and common market and myself, and I don't know that this is a disconnect, but if there were a disconnect, it perhaps would be do you need this level of coordination on day one when you open the second LMP next to the first LMP?

My feeling is you do, or you need something that is going to get you 75 percent of the way there, because I think what we can't afford is to err on the side of not coordinating and to generate enormous uplift costs that then are associated with the new market that taint its introduction.

CHAIRMAN WOOD: What are the implications to customers of not resolving this issue?

MR. PATTON: First there's just straight inefficiencies because one RTO is going to be doing things that are wildly inefficient potentially to try to resolve congestion that could be more much more efficiently solved by the neighboring RTO.

But what that will do is a couple of things. One, the prices in the RTO area that's causing the congestion won't reflect the congestion, so you'll be sending bad price signals.

I'll give you an example that is probably a good example. I couldn't name the flowgate, but take Commonwealth Edison and the Wisconsin Upper Michigan area. The MISO is dispatching Ohio, lots of Illinois, or a big part of Ohio, and then most of MAPP. If the Midwest ISO were to dispatch generation in Ohio to serve load in Wisconsin and Upper Michigan, that power is going to flow right through AEP and Commonwealth Edison.

Now if it causes a constraint on Commonwealth Edison's system that normally would limit transfers into the Wisconsin Upper Michigan area, and the Midwest ISO is completely ignorant of that constraint, the prices in Wisconsin and Upper Michigan aren't going to reflect the constraint. You're not going to see prices that reflect the congestion. At the same time, you're going to have Commonwealth Edison wildly trying to keep this constraint from binding.

This is in the no coordination case. I don't think anyone thinks that's actually going to happen. But they will be redispatching, but they're not going to be -- their settlements or such because most of the flow is going to be loopflow, that MISO, who should be paying for the congestion won't be, and therefore, you'll have very large amounts of uplift being incurred by Commonwealth's load.

That's an example of a potential issue, and that is the issue in an LMP market is when you have loopflows, if you're on an island, you always collect enough money from everyone who is causing congestion and relieving congestion that you can pay your transmission rateholders. But once you start incurring loopflows which are not billed for the congestion that those loopflows cause on the system, you're going to have underrecovery potentially, and then you're going to have to collect uplift to pay for that.

CHAIRMAN WOOD: I have a one-word answer to all that -- yuck.

COMMISSIONER BROWNELL: It seems to me like we ought to have a chat with some folks.

CHAIRMAN WOOD: Thank you for that. I'm going to have to re-read the transcript on some of that. You're too smart for me, but I'll figure it out. Thank you. Questions for David?

(No response.)

CHAIRMAN WOOD: Other thoughts, David?

MR. PATTON: No. There are some areas in the report that we haven't covered that are probably good to review, in particular the status of the development of the market rules and the fact that I think there still needs to be some work on shortage pricing, which is sort of the missing component in a lot of these markets.

CHAIRMAN WOOD: Meaning what?

MR. PATTON: Meaning that we have reliability requirements that have, both short-term and long-term, to have generation in certain areas, and when we can't meet those requirements, our markets don't set prices efficiently.

This was an issue in New England about a year and a half ago. It prompted some pre-S&D changes. You'll be seeing a filing from New England to address the same issues post-S&D. You are looking at one from New York to address precisely the same issue. And hopefully, you'll see one in the Midwest as well before those markets get started.

But it is the kind of thing that you need to solve the Southwest Connecticut issue. LMPs alone don't send the signal that you're really capacity short in those areas.

CHAIRMAN WOOD: One issue we're seeing kind of across the country, I guess it's probably mostly, Bob, in your area, but we have seen it and may see it again in California, so I'm not sure. It's the RMR contract issue. And it's kind of this, I don't know if it's a philosophical gulf, but it is kind of a policy fork in the road between an RMR-based for load pockets and one that looks more like, what do we call it, DCA? We called it DCA one place and NCA somewhere else.

You all want to work on an acronym. You three guys and a couple of others kind of write the book on what acronyms we need. Obviously we grappled with it just as recently as Friday to come out with an order for ISO New England which I can't characterize as anything more than a mental band-aid until we kind of get through the more philosophical issues about how are we going to get investment in to structurally solve the problem while still keeping the lights on between now and the time that market result happens. So, open mike.

MR. PATTON: I'll give you the options that you have, and I'll give you an indication on why I say LMPs alone don't solve this problem. In most of these load pockets, you have essentially reserve requirements. In New York City, there is a specific number of megawatts that have to be on line in order to make sure that New York City can recover from not only the first contingency but the second contingency.

What that means is we are running reserve markets in New York that set prices for eastern New York and statewide that reveal the marketwide capacity requirements, and when I say capacity in this case, I'm talking about operating reserves, hour-to-hour capacity requirements, our markets don't reveal that capacity requirement in New York City. And the way shortage pricing ought to work is, that the first sign that you're going into shortage is you're short of reserves. And the question then is what are my reserves worth? Because every megawatt of energy I could get in that area would allow me to restore one megawatt of my reserves.

So energy has to be worth what the reserves are worth that you're sacrificing. And when we set $1,000 bid cap, you're setting a de facto value for reserves at $1,000, so that New York will tell suppliers in Canada, please don't offer above $1,000 even though it would allow us to maintain our reserves, because our reserves aren't worth any more than $1,000. That's sort of the implicit story.

When that happens, or when we go into reserve shortage, if you actually reflected that in a price in the area where you have the reliability requirement, the price would be $1,000, or it would be whatever the value of the reserves are that you're not able to meet. And we go into reserve shortages in these areas. And the problem is in an LMP, you just dispatch the reserves, and prices can actually go down when the operators decide to dispatch the reserves, and you certainly aren't recognizing the cost of what you're sacrificing, which is your reserves in those areas.

Secondly, because you have a capacity requirement in a place like New York City, you turn on a lot more generation in those areas than you would normally, and we do the same thing in Southwest Connecticut and Boston. What that does is it decreases the LMP difference because you have a lot more supply coming on in those areas than would be optimal if you didn't have that capacity requirement.

So at some point we need to say, okay, when we're going into shortage, we're going to reflect the cost of what we're sacrificing, which is our reserves. And the convenient thing about doing that is no generators have to raise their bids in order to cause prices to move up when you're going into shortage, and it allows you then to not rely on looser mitigation to try to get prices roughly right in these areas, which is a wonderful thing for both generators and the market.

And were we to do that everyplace, you probably wouldn't need very many RMR contracts because you would be signaling the true value of generation in that area. And the reason the operators say you can't lose any of the Southwest Connecticut generation is because they have to meet these requirements. But the markets have no way of signaling that they're providing that service.

Now New York deals with this, the alternative for dealing with this, New York City deals with this by having a locational ICAP market or requirement, and that's sort of a second best solution. It says, well, if in total I have a certain amount of capacity in New York City, then I think I can meet these day-to-day capacity requirements. And when we're starting to run short of that, you'll see significant revenues being generated in that market, and that will help you out of your RMR problem.

And lastly, your last choice is RMR cost of service treatment, which I think is probably perhaps the least attractive. But if you don't have either of the former, you're probably going to be stuck with a lot of the latter.

CHAIRMAN WOOD: So you would define the number one best solution to be something like a DCA or NCA approach?

MR. PATTON: No, no.

CHAIRMAN WOOD: I'm sorry. Walk me back through.

MR. PATTON: No. The two approaches that I think are most attractive are to set a market requirement that corresponds to this short-term capacity requirement. So in New York, that would be a locational reserve requirement, for example. And when you can't meet it, then the value of energy reflects the value of the reserves you sacrificed.

CHAIRMAN WOOD: But you characterized that as the second best option.

MR. PATTON: No. The second-best is the locational ICAP.

CHAIRMAN WOOD: Aha. The difference. Okay.

MR. PATTON: Yes, the yearly or monthly.

CHAIRMAN WOOD: So the New York issue you're talking about is the one that was filed here a couple of weeks ago, the demand curve for reserves or --

MR. PATTON: Well, actually, there are quite a few things pending from New York. There's a demand curve for capacity, which is the long-term capacity ICAP that's been filed, and then there's a scarcity pricing proposal which got enormous support from the stakeholders, which is designed to reveal where you can't meet your reserve requirements, you'll get -- your ten-minute requirements, the prices will rise to $1,000.

Now because our reserve requirements don't go down to the location level, like New York City, that will primarily affect sort of marketwide shortages, either Eastern New York or statewide. But if you don't do either of the first two, because you don't have an ICAP market to work with and you don't have reserve markets to work with, and this is where Midwest has gone, is you can build in a buffer in the mitigation and hope that you actually have market power in the areas where you have these locational constraints that would allow the prices to rise in accordance with the proxy CT proposal that you may have seen.

The problem with that proposal is that if you don't have market power in those areas, it could be the case -- it's not the case -- but it could be in Southwest Connecticut that all the generators would be owned by different firms and you have no market power, in which case the proxy CT approach won't generate any benefit, and that the last option is the RMR.

MR. ETHIER: I agree with David's assessment of the problem. I guess I'll sort of address your question on maybe a sort of broader scale, which is the way New England is sort of seeing the way this ought to shake out, and the way we would like to see it shake is, in the near term, we brought the proxy CT proposal forward because we couldn't do the things that David identified in a very short term, which is locational ICAP, is sort of our intermediate-term solution at least. And you recognized that in your order on Friday, encouraging us to continue along that path.

So we view, you know, there are sort of two tracks that we need to proceed down. One is get these market improvements in place which sort of deal with the problems David just sort of detailed, locational ICAP. In New England's case, it also includes reserve markets, it includes scarcity pricing, complete set of markets is sort of how I'm describing it.

And that's clearly key, and we don't have that now, which is one of the reasons we have problems in Southwest Connecticut. We have one ICAP number which is virtually zero now because of the capacity situation, which, for Southwest Connecticut, you're really buying a product that's not reflected in the ICAP market as it's currently constructed.

So that's a positive move that within a year we should be able to take care of. But there's another avenue, which is these RMR contracts. And my view on those contracts is there's always going to be -- you need to have provisions for those as a short-term solution to bridge a gap or to maintain a unit that's sort of really idiosyncratic and sort of part of the transmission system that you probably don't want to build a market around that, for example. That wouldn't be good policy. But you need to keep it around.

And to me, the question then becomes, what does cost of service mean in the new world?

In the old world, cost of service had a very clear meaning -- it's everything. In the new world, there's a case to be made that cost of service could be something quite different.

If you make the decision that you want to operate in a competitive market, you sort of have given up your rights to the old cost of service treatment. It's been likened to a bread and water treatment. You want to keep these units around, but that's all you're attempting to do here.

To me, that is something that needs to be actively considered. We're sort of going through that discussion internally, what ought an RMR contract look like, including what ought the recovery be to interact well with these markets. It's very easy to see situations where units would be far better off on an RMR contract than any possible set of well-functioning markets you could construct.

You know, old, inefficient units that hardly ever run aren't going to make much money in the market. Any decent market design isn't going to provide them with necessarily large amounts of fixed cost recovery. The question is, do you want to provide an alternative to them, that they have no incentive to get out of, no matter what market redesign changes you make?

While I certainly can't provide firm answers on what it ought to be, that's clearly something that needs to be wrestled with, and I think needs to be -- we need to have that discussion with our stakeholders, and everybody's explications need to be on the same page on what it means to them and what they can expect if they seek this sort of treatment.

MR. LARCAMP: Is locational price-responsive demand, a third part of the solution?

MR. ETHIER: I think that's part of the complete markets, you know. My failure to mention it doesn't mean that it's not important, but I think that's part of complete markets and letting price-responsive demand play as big a role as it's able to play.

Our supply sides are really well developed. We have to make sure our markets accommodate demand-side resources, as well as they do supply side.

MR. LARCAMP: I just think places like New York City and Southwest Connecticut could benefit from a renewed emphasis on price-responsive demand, which seems to be part of that solution.

MR. ETHIER: I agree. The trick, at least in New England, is to get it to really do its job when we need it.

MS. SHEFFRIN: I don't want to speak on behalf of RMR contracts, but I think that in California, we have formulated them in a way that helps the longer-term investment decision. These are costs that are given to the TO, where the constraint exists. The TO sees that balance. Is there something else I can do, rather than continue to pay this bill? We have seen one TO put in substantial transmission investments as a result of it, or formulate demand-side response.

I think we have RMR contracts that are forward-looking, costs which Bob mentioned. We do, in a sense, have an RFP for them, where a whole variety of people can bid. I'll pay for the upgrade, I'll take that contract cost and pay for the upgrade; I'll take that contract cost and pay for demand-side programs to go in the locations. There are ways to formulate an RMR contract which is more progressive.

CHAIRMAN WOOD: Are the RMR contracts of general uplift to the whole control area?

MS. SHEFFRIN: They're not, but they are to the constrained area, so the cost gets allocated to the constrained area.

MR. ETHIER: I'd just chime in on that point. That's a key element, I think.

CHAIRMAN WOOD: You've got that, too, right?

MR. ETHIER: The key is, I think we just got it on March 1. Previously, it was socialized. That move is clearly a good one, in my view.

CHAIRMAN WOOD: So in both California and in New England, you've got at least a zonal cost causation type approach toward dealing with these RMR type issues.

MS. SHEFFRIN: I wouldn't even say it's zonal; it's locational. The transmission owner sees the bill and says, well, I'm paying for this specific location. Is there some alternative that I could do to reduce this cost?

And we have seen them put in the transmission upgrades or other types of programs, rather than continue to pay it year after year.

CHAIRMAN WOOD: So the bill goes to the TO in California. Under SMD in New England, it goes to --

MR. ETHIER: The local LSCs/TOs, depending on if they fulfil those dual roles.

CHAIRMAN WOOD: Is there a difference then of how those costs could get recovered from the ultimate customer in the two regions?

MS. SHEFFRIN: I believe --

CHAIRMAN WOOD: What incentive does a TO have, if he could just flow it through?

MS. SHEFFRIN: There is a question of if they can flow it through, then it's just cost of doing business, and I don't have to optimize. I believe there are some performance-based mechanisms in the retail design, but, again, that shows how the wholesale and retail are linked.

You have to look at those incentives that are created in these markets all the time.

MR. ETHIER: Probably that gets to the nexus between the state regulators and the TOs, how they view that. Transmission is clearly a much more complicated beast in some respects and sending a signal to TOs, that's a good point, sending it there, and what happens to the signal once it arrives there is a good question, and hopefully the state regulators will recognize that that needs to be evaluated in conjunction with the TOs.

CHAIRMAN WOOD: Your timing couldn't have been better. Thank you all for coming today. Staff, any final thoughts?

(No response.)

CHAIRMAN WOOD: Great, meeting adjourned.

(Whereupon, at 12:40 p.m., the open meeting was concluded.)