BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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IN THE MATTER OF: :

CONSENT MARKETS, TARIFFS AND RATES - ELECTRIC :

CONSENT MARKETS, TARIFFS AND RATES - GAS :

CONSENT ENERGY PROJECTS - HYDRO :

CONSENT ENERGY PROJECTS - CERTIFICATES :

DISCUSSION ITEMS :

STRUCK ITEMS :

- -x

COMMISSION MEETING - 797TH REGULAR MEETING

OPEN SESSION

Hearing Room 2 C

Federal Energy Regulatory

Commission

888 First Street, N.E.

Washington, D.C.

Wednesday, June 26, 2002

10:15 a.m.

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APPEARANCES:

COMMISSIONERS PRESENT:

CHAIRMAN PAT WOOD, III, Presiding

COMMISSIONER LINDA KEY BREATHITT

COMMISSIONER NORA MEAD BROWNELL

COMMISSIONER WILLIAM L. MASSEY

SECRETARY MAGALIE ROMAN SALAS

1 -- continued --

APPEARANCES (CONTINUED):

JOE BROWNING, PJM

ROBERT (BOB) ETHIER, ISO-NE

ANJALI SHEFFERIN - CALIFORNIA ISO

DAVID PATTON - NYISO

STEVE BALSER - NYISO

DOUG BOHI - AEP

JIMMY STATON, Senior Vice President, Distribution and Transmission Dominion Resources

CRAIG BAKER, Senior Vice President, Regulation and Public Policy, American Electric Power Service Corporation

STAN SZWED, Senior Vice President, Transmission FirstEnergy Corporation

SUSAN FLANAGAN, Vice President, Dayton Power and Light Company

PATRICK MULCHAY, Group President, Merchant Energy Northern Indiana Public Service Company

ELIZABETH (BETSY) ANNE MOLER, Senior Vice President Government Affairs and Policy, Commonwealth Edison Company

KATHRYN K. PATTON, Senior Vice President and General Counsel, Illinois Power Company

GARY L. RAINWATER, President and COO, Ameren Corporation

-- continued --

APPEARANCES (CONTINUED):

NICK WINSER, Senior Vice President, National Grid USA

KENNETH LAUGHLIN, Vice President, Market Operations

PJM Interconnection, LLC

JAMES TORGERSON, President and CEO, Midwest ISO

ALSO PRESENT:

DAVID L. HOFFMAN, Court Reporter

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P R O C E E D I N G S

(10:15 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 duly posted in accordance with the Government in the Sunshine Act for this time and place.

Commissioner Massey is going to be participating by phone today. I understand he had to fly to Fort Worth, Texas, to take care of a medical emergency with his 91-year-old mother.

We just want to wish him and her the best, and appreciate his good example.

Let's start the day, as we do, with the Pledge to the Flag.

(Pledge of Allegiance recited.)

CHAIRMAN WOOD: Thank you. Madam Secretary?

SECRETARY SALAS: Good morning, Mr. Chairman and good morning, Commissioners. As you stated, Mr. Chairman, Commissioner Massey is joining us this morning by telephone. Good morning, Commissioner Massey.

COMMISSIONER MASSEY: Good morning.

SECRETARY SALAS: Mr. Commissioner Massey, I will call your name when it's time for you to vote.

1 The following items have been struck, since the

Commission's release of the Sunshine Notice for this meeting on June 19th: E-6, E-11, E-18, E-19, E-31, and C-8.

The consent agenda for this morning is as follows: Electric Items E-2, E-3, E-7, 10, 12, 13, 14, 15, 16, 17, 20, 22, 24, 25, 26, 28, 29, E-30, 32, 33, 34, 35, 36, 37, 38, and 40.

Gas Items: G-1, 2, 3, 4, G-6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 32, 33, 34, 35, 36, 37, 40, 42, 43, 44, 45, and 46.

Hydro: H-1, 2, 3, 4, 5, 6, and 7.

Certificates: C-1, C-2, C-3, C-4, 5, 6, and 7.

The specific votes for some of the items are as follows: E-32, Commissioner Massey dissenting, in part, with a separate statement; Commissioner Brownell concurring, with a separate statement; E-37, Commissioner Brownell concurring with a separate statement; G-22, Commissioner Brownell concurring with a separate statement.

Commissioner Brownell votes first this morning.

COMMISSIONER BROWNELL: I vote aye, noting the concurrences on E-32, E-37, and G-22.

SECRETARY SALAS: Commissioner Massey, may we please have your vote?

COMMISSIONER MASSEY: Aye, with a partial dissent on E-32, as noted.

COMMISSIONER BROWNELL: Aye.

CHAIRMAN WOOD: Aye. I would like to mention in today's consent that we generally do like to focus on the projects, the certificates that have gone out, I think, in light of the other presentations that will take a substantial amount of time today.

We eliminated that, but you can see one, Tennessee, where we give a certificate to Tennessee to expand the system at Leidy Hub to serve gas in the northeastern markets.

In C-3, in Texas Eastern, we give a certificate to expand its system into New York, and in C-7, Northwest, we issued a certificate for Northwest Evergreen Project to increase electric generating capacity in Washington State.

So I always want to call attention to the infrastructure investments that are being made in this country by certificate-holders that we work with. I appreciate the fine work that Staff does to address the myriad landowner, environmental, and regulatory issues with those, in such a timely manner.

SECRETARY SALAS: Mr. Chairman and Commissioners, at this point, Commissioner Massey will return to attend his family responsibilities, and he will no longer be on the phone. Thanks, Commissioner.

COMMISSIONER MASSEY: Thank you.

SECRETARY SALAS: The first item on the discussion agenda for this morning is A-3. We would like to remind the panelists for this morning that each one of them will get ten minutes for their presentation this morning.

Two minutes before their time is about to expire, we will notify the panelists that the two-minute warning is set. We have presentations by Mr. Joe Bowring of PJM; Robert Ethier of ISO-New England; Anjali Shefferin, California ISO; David Patton, New York ISO; Steve Balser, New York ISO; and Doug Bohi, AEP. This is Item A-3, state of the market presentations.

CHAIRMAN WOOD: Before you all start, I would like to put into context here, just what this represents for us. As you all know, it certainly is a priority of our Commission and our strategic plan adopted last September, and a lot of the steps that we've made since then to really bring together the best minds at the front line, which you fine folks represent, as well as the folks here at the Commission, to really escalate and elevate to a level of really primacy, our responsibilities in market oversight.

Certainly, the creation of the Market Oversight Investigation, recently, which takes a lot of the folks who have been doing market work at the Commission over many years, and puts them into one place, as well as acquiring and attracting talent from the outside.

That may not have been acknowledged, that FERC did this job, as well as create more of a formalized opportunity for us to work, both at the Staff level and on an ongoing basis, and in communication with the full Commission and hopefully on a more frequent basis, perhaps two, three, or four times a year, with the different markets.

We look forward to your number growing over the next several months, as we have more RTOs and ISOs, as more RTOs come into being. But I think the important thing that I want this to be is the beginning of a public and ongoing relationship between you, who are the front line of the marketplace, the eyes and ears at the front line in California, New York and the AEP region in New England, and in PJM, with us, who have to implement the Federal Power Act in the 21st Century.

I want to, I think, state the obvious: The market oversight responsibilities that you do and that we do to back you up, are a front line top goal item for this Commission, and will be for many years to come.

Thanks for being the first in this effort to reorient our public and private face toward a much more involved approach toward market oversight. As we have seen in the past, certainly for the year I have been on the

Commission, and in the past several years of this

Commission's existence, it's a very critical and important responsibility.

I appreciate you all taking time out of your summer market oversight, which is usually the busy time of year, to come and visit with us today. We look forward to your reports and your wisdom and some interchange between us and the Staff.

At this time, I'd like to turn it over to Bill Hederman to introduce the program.

MR. HEDERMAN: Thank you, Mr. Chairman. As I'm sure you are aware, with the large size of the panel, the ten minutes will barely give each monitor time to scratch the surface of all the intensive analysis and work that they have been doing, but we within the Commission Staff already have very healthy ongoing working relationships with the monitors.

That will certainly be growing. I was happy to be able to inform them, as planned, before the end of June, we'll have about 30 people of the Commission Staff appointed to OMI. And we'll have much more capability to work with them and to leverage their work on the front line.

The plan is for each person to present the state of the market. Please feel free to ask questions at any point, whether it's clarifying, as they are speaking, or at the end. And I think this will be a great discussion. Joe

Bowring will be presenting PJM, as the Secretary said; Bobby Ethier, New England; Anjali Shefferin on California; David Patton and Steve Balser on New York, and then Doug Bohi, who is presenting not on an ISO, but on his review of the AEP market, which was authorized by the Commission in the context of the recent merger, so that will have a little mix of apples and oranges here, but I think that will be useful. Joe?

MR. BOWRING: Thank you for the opportunity to be here this morning. As Bill pointed out, it's a little difficult to do the entire state of the market in eight minutes, but I'll give it my best.

The basic conclusion is that in PJM in 2001, the markets worked effectively -- not perfectly but effectively.

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(Slide.)

MR. BOWRING: The energy market was reasonably competitive, again, not a scientific term. The capacity markets experienced, as you know, a period of market power in the early part of the year; subsequently, they were reasonably competitive.

The regulation market and the FTR auction market were reasonably competitive. Turning to the energy market, the basic tests we use for the energy market are fourfold:

(Slide.)

MR. BOWRING: The first is the net revenue test. The net revenue test simply compares the net revenue from the energy market first, and then, in addition, then capacity markets, ancillary services markets, and operating reserves, it compares the net revenues from all those sources to estimates of the fixed costs of maintaining a marginal unit in a market like PJM.

Clearly, to the extent to which net revenue grossly exceed or are less than the capacity costs of the unit, it has implications for the level of competition. One would expect that in the long run that net revenues would be about equal to the fixed carrying costs on a marginal unit, and, in fact, that is pretty much we've seen over the last few years.

In 2001, net revenues were actually somewhat in excess of the carrying costs of a CT.

(Slide.)

MR. BOWRING: The reason for that was primarily the capacity market. As the result of the exercise of market power in the capacity market, the weighted average capacity prices were higher.

The contribution of revenues to capacity were higher, and, therefore, the total dollars of net revenues somewhat exceeded that required in order to cover the cost of the CT.

We also look at a markup index, again, an essential component of looking at market power.

(Slide.)

MR. BOWRING: It is focused on individual units. It compares the price in the market to the competitive price or the price that would occur if the marginal units were charging marginal costs.

(Slide.)

MR. BOWRING: And the general and market indexes in PJM were modest.

(Slide.)

MR. BOWRING: We looked at the markup for every unit, setting the price in every five-minute interval during the year, energy market structure, again, looking at HHIs, understanding that the HHIs are somewhat gross measurements, still having some meaningful content.

(Slide.)

MR. BOWRING: Looking at the overall energy market, HHIs were in the moderate level, averaging 1400.

(Slide.)

MR. BOWRING: We did see a cause for concern, however, when looking particularly at HHIs by segment of the supply curve.

In fact, we see somewhat elevated HHIs,

significantly elevated HHIs for both the intermediate and peaking portion of the supply curve.

CHAIRMAN WOOD: Joe, how do you define that, by capacity factor?

MR. BOWRING: No. It was an engineering judgment, basically. It's base load, intermediate, and peaking units. Engineers can draw a fairly bright line. You have steam units as base load, coal and steam is base load. Combined cycle, typically gas-fired, oil-fired, and then oil and gas-fired CTs are the top.

CHAIRMAN WOOD: So what percentage of the total energy in PJM would intermediate and peak represent?

MR. BOWRING: That's a good question, and I'm not sure I know the answer off the top of my head. In addition, looking at energy market prices, typically in PJM, as you can see by looking at the energy market price slide, prices exceed the $100 level above 1.0 to 1.5 percent of the year.

(Slide.)

MR. BOWRING: In 2001, that continued to be the case. There are a number of ways to look at price comparisons.

The simple average price is increased by about 15 percent.

(Slide.)

MR. BOWRING: A more meaningful measure is load rate, which reflects exactly what load is paid. Load-weighted prices rose about 19 percent.

(Slide.)

MR. BOWRING: If we took account of increased costs, as we would in any market, the fuel costs increased over 2001 at 7.6 percent, and finally taking account of the high demand week, there was one very hot week in PJM during the summer of 2001, the week of August 6th.

If we remove that week, just as a test, without that week, prices would, in fact, have fallen about 5.7 percent. What this illustrates is that prices in PJM have followed what would be expected to be market dynamics.

(Slide.)

MR. BOWRING: When costs go up, prices go up, and then when load and demand rises, prices rise.

We also looked at the difference between day-ahead and real-time prices. Day-ahead and real-time prices converge only about 37 cents apart on average over the year. They vary a little bit more if you look at it hourly.

However, in general, the prices between the day-ahead market and real-time converge.

CHAIRMAN WOOD: If they didn't what would that indicate?

MR. BOWRING: What it would indicate is lack of liquidity, a lack of market participants arbitraging the difference. The PJM market is very liquid. There are a lot of players making what we call financial bids, ink and deck offers, and they tend to drive those prices together.

If they differ, somebody can make money by driving them together, and that's, in effect, what happens.

Overall, the conclusion is that the energy market, as I say, is reasonably competitive.

(Slide.)

MR. BOWRING: The recommendations I am making are: The first, a no-brainer that everyone recognizes, that is easier to say than it is to do, and that is additional actions are required to increase demand-side responsiveness.

(Slide.)

MR. BOWRING: PJM and FERC have implemented a new program for PJM for the summer, but additional work needs to be done. In addition, the retention of a thousand-dollar offer cap, as well as the other market power mitigation features of the PJM market, which I have discussed with you before.

In the capacity markets, as you know -- I'm sorry.

CHAIRMAN WOOD: My minutes count for me, not for you.

(Laughter.)

CHAIRMAN WOOD: I think the demand side response is clear. Why would your recommendation, in light of your findings on the energy market that you just laid out in your report, why would the conclusion be to retain the one-thousand dollar offer cap?

MR. BOWRING: The one-thousand dollar offer cap is still binding on very high load days and in the absence of full demand-side response.

CHAIRMAN WOOD: You link to that, not just something we found in the other data?

MR. BOWRING: Absolutely. In the capacity market, as you know, we had a market power issue in the first quarter of the year. You can see the results of it when you look at the price curve.

But as with the energy market, we looked at a number of measures of competitiveness, including market structure, outage rate performance, and prices. Market structure is actually a cause for concern, and the capacity market -- in general, the capacity markets were highly concentrated, both daily and multi-monthly, the equivalent of less than the participants on the supply side in any individual monthly or multi-monthly market; the equivalent of about four in individual daily markets.

So, clearly, that's a concern. One positive result of the capacity markets was clearly an increase in reliability. That's the function of capacity markets, and they serve that purpose.

In addition, the incentives associated with capacity markets have played a role in providing incentives to have reduced outage rates. The graph shows that forced outage rates in PJM have continued to decline since the introduction of competition.

CHAIRMAN WOOD: So, Joe, when I look back on the page on the front of your presentation, you broke out annual net revenues of $40 CT and up. You're showing about a third of the dollars, well, a third to a little more than that, two-fifths of the dollars coming from capacity?

MR. BOWRING: It's actually almost half -- 37,000 out of 88,000.

CHAIRMAN WOOD: So that's really -- by the capacity market, you really mean -- is it just the ICAP product alone that we're talking about?

MR. BOWRING: Yes. What we have the ability to look at with crisis is the capacity credit market. It really is on the energy side, a clearing market, but nonetheless, we know that that clearing market has a big impact on the bilateral market, and, therefore, affects the prices. So it's a reasonable measure of the price.

And if you compare the capacity market revenues in 2001, for example, with prior years, you can clearly see that they're really significant this past year.

The capacity market price graphs show a couple of things: They show, in particular, if you look at the second one, that prices rose in the summer of 2000 and they rose in early 2001.

In the summer of 2000, we found that the reason the capacity market prices rose was underlying fundamentals. It made sense for prices to rise.

CHAIRMAN WOOD: Are you talking about this one here?

MR. BOWRING: Yes, the first spike in the daily market prices reflects and reflected underlying fundamentals in the market. The PJM market was actually short. The structure of the market at that time, which relied heavily on daily markets, that individual entities were going to the daily market to meet their needs.

The market, as a whole, was short, and as a result, prices reflected that, and that's what we found at the time. So, obviously, high prices are not the issue.

(Slide.)

MR. BOWRING: However, the exercise of market power is. In the first part of this past year, 2001, we found that there was an exercise of market power in the capacity markets. We moved to resolve that.

You adopted changes to our market rules, which effectively alleviated the problem in the short term.

SECRETARY SALAS: You have about one minute left.

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CHAIRMAN WOOD: I'm going to give as many as he wants, because this is really kind of good stuff.

(Laughter.)

CHAIRMAN WOOD: How do you differentiate between the two peaks? One is okay and one is not. Walk me through kind of the market monitoring analysis.

MR. BOWRING: In the summer of 2000, we were relying -- the markets relied heavily on the daily capacity market, the obligation was daily. It could be met daily.

As a result of prices in the summer of 1999, which were very low in the summer daily capacity market, a lot of load-serving units decided they were going to meet their needs for capacity in the daily market in the summer of 2000. As a result of the incentives and the differentials in energy prices, forward energy prices, actually between ECAR to the west, and PJM, it became more profitable for capacity owners to sell some capacity out of the market into ECAR as energy, liquidated damages energy, and to retain it in PJM.

As a result of those economic forces, a real reflection of opportunity costs, the PJM market became short, and the result of that shortness was higher prices, due to the way that the rules work and the way that supply and demand works.

When the market is short of supply, not surprisingly, the prices rise. That was the essence of what happened there.

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CHAIRMAN WOOD: And so then the real change that -- then the short capacity issue is what it is. That's actually where we want the price signal to be sent. So you don't do anything to temper that. But the market structure issue was remedied by moving to, what was it, a seasonal market?

MR. BOWRING: Exactly. The integral market would become effective July 1st of 2001. That's exactly right. The reason we proposed those changes was exactly because of what happened in the summer of 2000.

CHAIRMAN WOOD: Okay.

MR. BOWRING: And the result, not surprisingly, has been the most demand for capacity credits has moved out of the daily markets into the longer term and bilateral markets.

CHAIRMAN WOOD: And this just reflects really -- oh, I see the black line reflects what the month -- is that more of a bilateral type?

MR. BOWRING: No. All these prices reflect capacity credit markets operated by PJM. We don't have good transparent price data from the bilateral markets. We have anecdotal data. This reflects the data from markets that PJM runs.

CHAIRMAN WOOD: I'm looking at the volume bars at the bottom. Clearly, the -- why does the green bar have a positive number at all after July? Can you still buy daily capacity?

MR. BOWRING: Yes. The obligation is technically still a daily obligation, although the penalty structure provides a very strong incentive to meet your needs in an integral market. It still makes sense to have a daily market. Load shifts on a daily basis, and it retains the flexibility. The original purpose of having a daily market was to facilitate retail competition to make it easier to buy and sell capacity. So retaining the daily market retains that flexibility in the capacity structure.

CHAIRMAN WOOD: Did the exercise of market power account -- well, why don't we get the slide up here on this one. I don't know what number or page that is. That's it. No, that's actually not it.

(Slide.)

CHAIRMAN WOOD: That's it. If the second one reflects market power and then it was fixed in part by the seasonal market tariff, how else was it fixed? That was the fix for it?

MR. BOWRING: No, actually, the primary fix became effective June 1st. That was changing the allocation of deficiency payments. The approximate cause of the problem in January, February and March of 2001 was the underlying rule about how capacity deficiency payments are allocated, and in effect it gave any provider of capacity who was longer than the market was long could effectively set the price equal to the penalty rate, because they would receive the penalty rate regardless of whether they sold capacity or did not sell it.

So that was fixed on June 1st.

CHAIRMAN WOOD: So you've got a line now that at least on mine is black or the darker line, which is the weighted average price monthly. It seems to take over where the daily left of. But that's okay?

MR. BOWRING: The monthly and multi-monthly market prices that you see, the spike occurred as late as June and July. It reflects a lag. That is, a number of those markets are actually run during the time the market power was being exercised and it spread across all the markets.

CHAIRMAN WOOD: So that --

MR. BOWRING: Even though it doesn't show up until later, it was a result of the issues in the first quarter of 2001.

CHAIRMAN WOOD: Walk me through why that's so.

MR. BOWRING: If you're trying to buy capacity and you're trying to buy it for a longer period, say, in a six-month market, and you're in a timeframe when your alternative is to buy in a daily market for 177 and there are very few sellers. Clearly, if I'm a seller, I'm not going to sell anything for much less than that.

So regardless of whether an individual seller had market power in the longer term markets, the prevailing price in the capacity markets are being set by the exercise of market power in the short-term markets in the first quarter that effectually set what sellers' opportunity costs were.

CHAIRMAN WOOD: Well that had a long effect. Okay. Thanks.

COMMISSIONER BROWNELL: Can I just kind of jump onto that long effect comment? There was some gap -- correct me if I'm wrong, Joe -- between the time you identified that problem and the time that problem was brought to the attention of the Market Monitoring Unit here?

MR. BOWRING: We identified it in January. We made a filing. I'm not sure exactly when the filing was, in early February I believe on this topic. We made several filings. But the first one was in early February I believe.

COMMISSIONER BROWNELL: That was the filing with the fix. Is that right?

MR. BOWRING: Yes.

COMMISSIONER BROWNELL: Is it the policy of the PJM when you see a problem to pick up the phone and report it immediately without any kind of internal review of what it is you're reporting? Do you feel you have the authority to directly come to a Market Monitoring Unit, and today if this happened, you would be on the phone the moment you saw this?

MR. BOWRING: Absolutely. I felt I had the authority then. Clearly I have the authority now. You have ordered me to have the authority and told me to do it. It's in my plan.

COMMISSIONER BROWNELL: I just wanted to know if we were heard. Sometimes we're heard, sometimes we're not.

I want to talk about the demand side for a little bit, because that's been kind of a topic of conversation in PJM, and I think some pretty good plans were put forward and went through a kind of long process of review by stakeholders, and when they emerged at the other end, they weren't quite as strong as they might have been at the beginning. How do we solve that problem?

MR. BOWRING: This is in reference to?

COMMISSIONER BROWNELL: Demand-side management proposals within PJM. Given the strength of the market, the world was looking at PJM to kind of come out of the box with probably a pretty extensive and substantive proposal. There were some suggestions by stakeholders,including state commissioners, that the proposals got way watered down in the stakeholder process.

MR. BOWRING: I don't really agree with that. I didn't go to every meeting, but I went to a number of the meetings, and I think the debate there was extremely healthy, and I think the program was better as a result.

What you had happen was detailed, substantive interaction among the parties with very different interests, and all the proposals that came in actually did not necessarily make a lot of sense. I think the result was a very sensible program and one that passed almost everybody's litmus test for rationality. Clearly, we have to do more. Clearly, there are some interjurisdictional issues, metering for example, that have to be addressed. But I don't regard that process as a failure. I regard it as having been a success.

COMMISSIONER BROWNELL: And it was timely.

MR. BOWRING: Everything could always be done sooner. I think it would be much better to have the DSM programs, and I think everyone acknowledges this, done sooner so the market participants can plan and know the rules. So, much better to have it done in January than in March.

COMMISSIONER BROWNELL: Thanks.

CHAIRMAN WOOD: Why don't you finish up at about the same clip you were moving before I interrupted you?

MR. BOWRING: Let me just quickly refer to the regulation market and the FTR option market. The regulation market has a significant excess of supply over demand. The regulation market was in fact quite competitive during the year.

(Slide.)

MR. BOWRING: The FTR auction market, again, its primary function is providing residual FTR capacity to those who want to buy it on a monthly basis. And again, that market worked quite effectively. Prices rose, but again, prices there rose because they were reflecting the underlying costs of congestion.

Those are the four areas of markets that we look at: The energy market, the capacity market, the regulation market and the FTR auction market.

CHAIRMAN WOOD: On regulation, what kind of volumes are usually made? It look like around 400 megawatts.

MR. BOWRING: Yes. 1.1 percent of the on-peak and off-peak forecasted demand.

CHAIRMAN WOOD: Is the one with the HHI?

MR. BOWRING: I filed an affidavit at the time that PJM introduced the regulation market, and there was a little bit of concern about the level of HHI, but they were outweighed by the fact at the time, and the continuing supply is so much larger than demand.

We continue to watch that market, but there's a large overhang of supply.

CHAIRMAN WOOD: It said here a recommendation as to regulation markets. Retain the $100 offer cap in regulation market. When was that set and how was that established?

MR. BOWRING: That was set as part of the introduction of the regulation market, and as with all these caps, there's a certain amount of judgment involved. That applies only to what we could term the availability of the capacity portion of the payment.

Regulation providers are paid both that which is clear in the day ahead market as well as avoided costs. They get the higher of the day ahead or the real time avoided cost. The point there is to retain the dynamic link between the price we're paying for regulation and the price we're paying for energy so that the two don't get out of whack, so providers don't have an incentive to shift artificially between the markets.

CHAIRMAN WOOD: I'm looking at that extra chart for this one, and it shows for 2001 that in August it looks like it did pop up. That was that hot week.

MR. BOWRING: Exactly. And because regulation prices include opportunity costs, you'll see a spike in regulation price as well.

CHAIRMAN WOOD: Do energy prices also go up? I'm going back to that.

MR. BOWRING: Yes they did.

CHAIRMAN WOOD: So that would track that pretty much. Okay. What is the meaning of this chart? I was trying to figure out what did that mean, the chart right after it. Figure 5.

MR. BOWRING: PJM has defined regulation limits, and this simply shows the extent to which the amount of regulation fell within those limits. Again, the goal is not actually to have a certain amount of regulation. It's to maintain the ACE control area within certain bounds, and regulation is a key means of doing that. So this simply illustrates that performance in the regulation market improved post-introduction of the competitive market.

CHAIRMAN WOOD: What's considered a good number here?

MR. BOWRING: Basically, after the introduction of the regulation market, the numbers have averaged in excess of 90 percent. And again, the key is that we are meeting our ACE target, which we are -- the so-called CPS 1 and 2 targets. Certainly anything above 80 percent is great, and these in general reflect a significant improvement in that performance.

CHAIRMAN WOOD: How is that done prior to this being a market-based -- how is it acquired? Did PJM just go and have people under contract for it?

MR. BOWRING: No. It's a somewhat ad hoc cost based. We basically set -- broke regulation into three tiers and assigned a price to them. And the result was the incentive was really not to be there, for example, during overnight periods and sometimes when we needed regulation.

So, as I say, it was not contract. PJM was procuring on a somewhat ad hoc cost basis.

CHAIRMAN WOOD: Now is this -- the cost of regulation in the new system just up? Was it just spread to all LLCs in PJM, or do they have self-supply ability?

MR. BOWRING: I should know the answer. I believe you can actually provide it bilaterally, or you can self-supply.

CHAIRMAN WOOD: And then PJM does the rest and makes it available to people who didn't self-supply?

MR. BOWRING: Exactly.

CHAIRMAN WOOD: Then the FTR auction market, which was the last of your four markets that you're talking about today, tell me a little bit more about what that product is and how it's developed over the past couple of years as a market.

MR. BOWRING: The FTR auction is only one piece.

It's a relatively small piece. That is, it's the residual.

It basically provides the mechanism for both parties to trade bilaterally. But most importantly, in fact, during 2001, almost solely it was a mechanism for PJM to provide residual FTR capability to those who didn't have it.

So when PJM runs its engineering power flow analyses and determine that there are additional FTRs available in the system, we're going to make those available to the highest bidder.

But one of our recommendations is that PJM needs to look, and in fact PJM is looking actively and stakeholders are well on their way to resolving this issue that FTR allocation processes has resulted in a barrier to entry to retail competition. That in fact is being addressed, and there's a proposal coming out of what we call our market implementation working group to the energy market committee to resolve that. And I think it's actually a very good proposal.

(Slide.)

MR. BOWRING: That shows every promise of being resolved very soon.

CHAIRMAN WOOD: That sounds good. Characterize for me a little more clearly what the problem is.

MR. BOWRING: The problem in a nutshell is, if I'm a utility who inherited FTRs as a result of serving network load and let's say 80 percent of my load is hedged by FTrs, say I lose 10 percent of my load to a new load-serving entity, a new retail competitor, under the current rule, I don't have to provide any FTRs or no FTRs follow that load.

CHAIRMAN WOOD: Because?

MR. BOWRING: That's considered to come from the unhedged portion of the allocation as from the top 20 percent. The new rule will have FTRs under the new system perhaps ARRs, follow the load on a pro rata basis.

CHAIRMAN WOOD: As you can imagine, this issue is right before us right now. We're thinking about standard market design. It's good to hear you all thinking about it.

The FTR auction market, I'm looking at the last graph that you've got in the packet, Joe. Tell me what that graph is supposed to tell me.

MR. BOWRING: It tells you two things.

(Slide.)

MR. BOWRING: Its level of activity as well as prices. The line is prices. And as you can see, prices rose du8ring 2001. As I indicated a moment ago, that reflects really the fundamentals. It reflects the value of the FTRs. The prices are being set by bids to buy, so the highest bids to buy, the suppliers would come from PJM. So PJM is not directly setting the price and reflects the fact that congestion increased significantly in 2001, and the buyers reflect the level of activity.

CHAIRMAN WOOD: If I were to look at the right end of that, that would be a pretty good indicator of the overall cost of congestion.

MR. BOWRING: We have more direct measures of the level of congestion as stated in the report itself.

CHAIRMAN WOOD: So as recommendation number one, that's what's coming out of the working group. Talk a little bit about issue number two, the recommendation there. How will that manifest itself into PJM enterprise?

MR. BOWRING: The second recommendation is really to follow your order. That was to identify areas where transmission expansion investments would relief congestion where congestion may enhance market power and investments are required to support competition.

So I think PJM and market monitoring need to be more active in pursuing that order and develop better analytical techniques for identifying the areas where congestion is occurring because of underlying issues on the system, for example, rather than ongoing maintenance or upgrades, and then determine whether that congestion is associated with market power and whether it has market power implications and whether then PJM should have a method in place, an approach in place to require upgrades to transmission in certain cases.

CHAIRMAN WOOD: Does the HHI analysis of the other three markets assume -- do you assume PJM as the one sole market with no congestion?

MR. BOWRING: We look at HHIs a couple of ways. One, the HHI numbers I gave you earlier do assume that. However, in the report, we talk about the fact that the HHIs can be quite high in areas defined by transmission constraints. That's also a concern.

CHAIRMAN WOOD: If it's identified, and in fact identified and remedied, then we can actually get to a point where you get less of a local market power?

MR. BOWRING: PJM actually has a very effective system in place for addressing local market power. As you know, the ability to cost cap units for local market power for must run, at least for historical units built prior to '96.

CHAIRMAN WOOD: What's been your experience with that actually? What percent of the units within PJM would be subject to that sort of protocol?

MR. BOWRING: Again, I don't have the numbers at the tip of my tongue. I should have. It's not a huge percentage. Some units are affected on a fairly regular basis. It's a very effective means of addressing local market power and local market power moves around. It depends on the actual system conditions at any point in time. There are places where there is persistent need to run certain units on a must-run basis and cost cap them. But in general, it's been a very effective approach.

CHAIRMAN WOOD: Good. Very illuminating. Thank you.

MR. HEDERMAN: I have one question before we move on. Could you speak to the issue of expansion of PJM and what's on your analytic agenda and radar screen for things to worry about as you look at both contiguous integration and noncontiguous integration?

MR. BOWRING: From a competition perspective, I welcome the expansion of markets, larger markets, more participants. It's a very good thing for competition. Clearly it expands our ability to have information, to process information effectively. We're certainly working on that.

One area that identified the state of the market as well is the capacity market design. I think it's important to have a single capacity market design almost no matter what it is. As well, that market design needs to incorporate strong provisions to protect against the exercise of market power. But in general, expansion is a good thing for competition. Thanks.

MR. ETHIER: Good morning. Thank you for the opportunity to address the Commission. I am presenting for

ISO New England actually a preview of our annual State of the Markets Report.

Our schedule is a little different than everyone else's calendar year schedule. Our markets went live on May 1 of '99, so our sort of fiscal year ends May 1. Our report typically comes out on August 1st. So you'll be receiving sort of a sneak preview of what's going to come out August 1st. Unfortunately, I wasn't able to provide the detailed backup data that Joe was, because, to be honest, we're still putting it together.

CHAIRMAN WOOD: You can come back.

(Laughter.)

MR. ETHIER: Sure. I still think I have some interesting things to highlight.

(Slide.)

MR. ETHIER: The overview. Basically the market results for the last year have been very consistent with the past, once you adjust for fuel price changes. They're a more detailed analysis, and I'll focus on in particular two studies that have been done, one internal, one external, which take a in-depth look at competition in the markets, and those results have been quite positive; hazard some projections into what the future holds for our markets in terms of competition, and the near term looks stable to improving.

The market developments which we see on the horizon both that are sort of as we speak we've implemented what I view as very significant market rule changes for the summer of 2002, and we're still in the process of determining how those are working out. So far they've been working out well. But they haven't really been stress tested, but if the weather we have here today is moving north, by the time I get home, they may have been stress tested. We'll see.

And then of course we have the standard market design that ISO New England is adopting from the PJM platform, which of course is huge.

And then a couple of concerns would be load response and transmission constraints in New England.

(Slide.)

MR. ETHIER: Page 3, New England Energy Prices and Comparisons. My apologies to New York and PJM. The numbers that they see here aren't going to exactly replicate the annual numbers they see, because we've adapted them to our calendar year. But, you know, I think the interesting thing of this graph, the two dark lines represent New England prices. One is a load rated ECP, and that's the highest line on the graph. It shows a peak in 2000, 2001, reflecting high fuel prices in those years.

But I think importantly, the other line, the other solid line, which is basically flat, is adjusted for fuel prices, which basically show that we've had constant annual average energy prices in New England over the last three years, which when you look at our analysis, is desirable, because we feel we've had competitive energy markets over that time period. So the results have been pretty stable.

(Slide.)

MR. ETHIER: Next slide. The all-in price of energy in New England I think illustrates a number of things. It's important to realize that energy is still by far the biggest dollar contributor to the cost of wholesale power in New England. Ancillary services, uplift and capacity are relatively small chunks, if you will, of the total wholesale bill that's paid by load-serving entities in New England.

I think this figure or chart highlights a couple of other trends which are desirable. If you look at the uplift value in May '99 to April 2000, we had about $1.19 a megawatt hour. That's fallen to about 84 cents a megawatt hour.

In part, I would attribute that to the rule changes we adopted approximately a year ago which institute net commitment period compensation, which is distinct from our previous uplift rules in that it sort of takes into account the peak prices that you receive above your offer price and nets that out of the uplift pay you receive for the hours when you're actually more expensive than energy clearing price. That rule is consistent with what New York does. They have a different name for it, but essentially, their version of uplift.

CHAIRMAN WOOD: So then what comprises the 84 cents that's uplifted in the most recent reporting period here? What categories of costs?

MR. ETHIER: Two primary categories: Units that are needed to serve peak load on a given day to have minimum run times that exceed the amount of time you really want to have them run, and it would also include units that are run primarily to support the transmission system.

As I'm sure you're aware, our transmission management system is not as sophisticated as the one we're adopting with locational prices, so it's all done, in the New England vernacular, using out-of-merit generation. That rolls into the uplift category. The uplift number is never going to be zero, but depending on what the rules are for compensation, you can sort of affect them considerably.

CHAIRMAN WOOD: If I were to look for a number there, would that be the number of the cost of dealing with congestion, or is that buried somewhat in energy as well?

MR. ETHIER: I would say the uplift number you're seeing here is a composite number of congestion costs and also units that are running after minimum run times, for example, on hot days. In the report that we produced, those numbers are broken down much more clearly. What I have here doesn't allow you to sort of discern the difference.

CHAIRMAN WOOD: I'm struck I guess by the difference between the amount of revenue that comes from capacity in the New England market compared to what we just heard from Joe in the PJM market. I wonder what may explain that.

MR. ETHIER: You're jumping ahead of me.

CHAIRMAN WOOD: I just can't remember what the answer was.

MR. ETHIER: That's a good question. Our capacity market is trading at roughly $1 a kilowatt month, which comes out to about $12 a kilowatt year. I take it from Joe's slide they're trading at over $30 a kilowatt year, was my take on the numbers that he presented. I would attribute that primarily to the different capacity situations in the region.

As you'll see later, New England has quite a strong capacity situation, and it's only getting better. At least from what we can tell right now, we have new unit entry that dramatically exceeds our load growth. Basically, the supply and demand in the capacity market is governed by the available capacity in the units that we're getting. So I'd say that the capacity market is quite consistent with the competitive situation in New England. That's highly competitive in the unconstrained market.

CHAIRMAN WOOD: It's just such a dramatic difference in percentage of contribution to the cashflow of the generator.

MR. ETHIER: It really is. I should probably caution you a little in that this number is going to be a little different from Joe's number. I believe Joe was presenting net revenues, and this is not net. This is a gross number.

But I would say that your inference is correct. The $12 a kilowatt year number is clearly for a peaker going to be a much smaller proportion of their total revenues than the $33.

COMMISSIONER BROWNELL: If one believes, as theoretically we asked to believe, and don't actually, that ICAP is intended to attract investment and new generation, how is it that New England ends up with considerably more new generation than PJM? I'm hard pressed to understand that.

MR. ETHIER: That's a very good question. I've been, in another life, I was working on exactly that very problem, financing plants. There was a lot of investment on the table in New England back in '99 when the markets went live. And if you look at the lead time to get financing and the lead time to actually build the project, the projects that all rolling in right now were started long ago.

Those projects actually used fairly extensive use of forecasting, shall we say, to estimate their revenues for 2003, 2004, 2005, you know. I think the concern is that folks were overly optimistic about what the revenues would be in the New England market and nobody factored in all the other units were entering or they thought they would be better placed than the other entrants. I would say that it's an example of our market repeating the benefits of investor exuberance.

COMMISSIONER BROWNELL: God, wouldn't we like to see a little exuberance today?

(Laughter.)

COMMISSIONER BROWNELL: I hear what you say, but I think underlying that is that people are building projects and capital is coming to projects based on a whole range of forecasts, accurate or not, and that ICAP itself probably doesn't play the major role that some would suggest it was intended to. Is that a correct assumption?

MR. ETHIER: I think there's certainly some truth to that. Certainly when the forecasting is done in many of these cases when you stress test your financial assumptions, ICAP is one of the things you look at. What happens if your ICAP revenues decrease? Is it still a viable project?

From that perspective I would say, yes, it may be, if you will, one of the first things to go in any sort of projection. That said, I will say that it's reassuring that our ICAP prices have tracked new unit entry and that they were higher in '99, 2000 than they are right now. So at least the market is working sort of consistent with the entry trends that we currently see.

COMMISSIONER BROWNELL: You don't seem to indicate that you've seen the market power that Joe talked about.

MR. ETHIER: I'm sure you're aware of the issue that arise two years ago, but recently we haven't seen those examples. Now I have to sort of caveat that a bit by noting that the ICAP market in New England is a bilateral market. We don't have necessarily the transparency that Joe's group has to the ICAP market, because we aren't running the same sort of internal auction that PJM is running.

CHAIRMAN WOOD: So where do these data points then come from? It says bilateral ICAP.

MR. ETHIER: We get that from a combination of broker quotes in the trade press. We think it's important to take a look at that, but we don't have any special inside knowledge of the workings of the ICAP market beyond informal conversations with participants.

The next page, the priced cost market analysis, this is similar to an analysis methodology that Joe mentioned in his presentation.

(Slide.)

MR. ETHIER: The next two slides I'm going to outline two sort of significant analytical efforts that I think by performing these we get some significant insight into the markets. The way you perform this analysis is basically simulate a perfectly competitive dispatch of the market over the previous calendar year or multiple calendar years, based on the data that the ISO has about unit costs and so forth, and you compare the energy clearing prices that you actually realized with those costs.

While I wouldn't place so much stock in the absolute level, in the long run, I think it's very useful to see the trend. If you're getting a greater divergence between your ECP and your calculated benchmark level, you would want to be sure that's consistent with the bigger picture, supply/demand situation. And if it's not, that's a good early sign I think of market power.

You know, the conclusion from our internal study is that the market is functioning well with a very modest increase in prices above what you would assume as a perfectly competitive baseline. And when I say "perfectly competitive baseline", that needs to be taken very seriously as an estimate that you wouldn't necessarily expect the market to achieve because (a) there's a range of error in there, and (b) we are unable to include certain opportunity costs that are real and legitimate costs in the marketplace. But we do feel that this is a useful metric.

I would also note that our internal version of this study is consistent with an external study that the ISO commissioned by Jim Bushnell in California who's done it for a number of markets. He looked from the beginning of the markets to basically September of last year and came to a similar conclusion. So we have two studies using very similar methodology that both produce comforting results.

(Slide.)

MR. ETHIER: The second analysis actually of our market, which we commissioned by our independent market adviser, David Patton, looks a little more directly at economic and physical withholding. The one-line summary of his result is his analysis consistently indicates that the New England markets have been workably competitive over the span of 2000 I believe was the timeframe that he examined. I'm sorry, 2001.

Basically, he took a look at economic withholding and physical withholding and found that both had trends that you would hope to see in a competitive market, and important for both large participants and for, if you will, hot days, the results went in the correct direction. That is, the estimated levels of both of these factors decreased as loads increased.

I didn't include these, but the econometric results, which allow more sophisticated analysis of the interactions of these things, are consistent with these above observations.

(Slide.)

MR. ETHIER: Slide 7, Projections -- Reserve Margins. The first three years, '99 through 2001, are based on actual peak loads. 2002 and '04, there are obviously forecasts. This is what I alluded to earlier. Our reserve margins are quite high both by I think the standards of competitive markets that we generally see and also by historic system planning standards.

Two things probably deserve mention. One is in 2001, you see this sort of drop. That reflects the extreme demand we experienced last August. We set a peak load last August that we don't forecast to achieve again even this summer with our inherent load growth, so last summer was truly -- it's a top 10 percent of the top 10 percent occurrence, which is very far out there on your load distribution, and that accounts for the perceived low reserve margin there.

The other important thing to consider in these reserve margin numbers is that this just includes units that are currently being built or have recently come on line. It did not factor in any retirements. I would anticipate by 2006 we are going to see some retirements, and we have not been so brave as to forecast which units are likely to retire.

MR. HEDERMAN: On that, with your reaction regarding retirements, do you expect to see a smooth recovery in that generation of the boom-bust sort of cycle coming out of this?

MR. ETHIER: I think that's a legitimate concern. Given the capital intensive nature of this industry and the long lead times, I think it's a legitimate question as to whether we're going to get into a boom-bust cycle.

What I said earlier basically implied that we are experiencing the benefits of a boom right now. How that's going to play out in three years is very unclear. Certainly there are some retirements that we expect just because we know that units that are currently coming on line are likely to displace units in almost the same site owned by the same owners. But beyond that, it's really unclear. I think that's something that all electricity markets ought to be concerned about, and we just don't have enough of a track record to see how that's going to play out.

Projections -- HHIs.

(Slide.)

MR. ETHIER: This graph is comforting in that HHIs have steadily decreased. The big steps you see there are divestitures or breakups of portfolios, and I think the important thing I would like to focus on is the two different colored lines to the right which show April 2003 and April 2004 projections. HHIs continue to improve under our projections, and essentially that's because the new units that we're seeing in large part are being built by folks who don't own big portfolios in New England. That from my view is very desirable. We're just increasing the competition in New England.

I have 30 seconds left. I've already mentioned the market developments.

(Slide.)

MR. ETHIER: Price reforms for 2002. We've seen some evidence that the reserve market reforms have already been successful.

CHAIRMAN WOOD: I'll give you some minutes back. Remind me what those reforms were. Just remind me which ones these are.

MR. ETHIER: The reforms were quite extensive. They include enhancements to transactions primarily with New

York. It makes transactions more flexible.

The reserve markets were substantially revamped in that they cascade prices upward from less quality reserves to higher quality reserves, and they pay opportunity costs for all levels of reserves rather than just ten-minute spinning reserves. We also expanded the amount of reserves that we're including in our markets. The prices have gone up in those markets, which was anticipated, but the markets seem to have been functioning well since they've been implemented.

The other sort of major category of reforms is units which are allowed to set our energy clearing price, because we only have one energy clearing price, it's especially important in New England that we have good rules that under peak conditions allow appropriate marginal energy to set prices. So we've implemented reforms that allow external contracts when they are marginal energy to set prices, and importantly, allow peaking units when they are marginal energy to set prices.

I think the most innovative thing we've done is that when a flexible unit or an external contract -- and by "flexible", that includes peaking units essentially -- when they are required to meet our ten-minute reserve requirements, are also eligible to set the clearing price even if they're at their low operating limits. I'm not aware that any other markets have instituted that.

But what that does is that really reflects the inherent value you're placing on your reserves and the flexibility that those ten-minute units really are affected by how you dispatch your energy market units and so forth. And that's probably the reform that has not been put to the test. It really requires the system conditions to be relatively tight before you expect those to kick in.

We've had a few isolated instances where there have been reliability problems where we've seen the peaking units set price where they wouldn't have and send the appropriate market signal, but we haven't had the sustained hot weather that really pushes this out of the demand curve that produces the high prices to see how that really influences things. But we find these to be -- we think these are very important efficiency enhancing improvements for the summer, and we worked really hard to get those in for the summer, despite the fact that we see standard market design, our version of standard market design, coming into play very soon.

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(Slide.)

In 23 seconds, the two concerns I'd like to highlight our load response. We've increased the amount of load response we've gotten for the summer of 2002 over 2001. In one sense this is encouraging, but I think it's very important to note that a big chunk of that 83 megawatts is not only because we increased the general program but because we issued a region-specific RFP in Connecticut which pays a substantial fixed payment for load response over the course of four months for the summer. I think those megawatts would be exceedingly useful. However, the payment is quite high and after the summer is over, we need to think are the incentives that we're providing our load response program significant enough to get the desired level. Because I look at the 142 we have now is not what I would like to see. And this RFP suggests that we're going to have to ratchet that up substantially in the future.

(Slide.)

That ties very much with the last slide which is transmission constraints, very much a concern in New England, especially in this Connecticut and Southwest Connecticut region. We hope the NEMA/Boston situation will be significantly improved this summer.

CHAIRMAN WOOD: Because there is construction going on on transmission?

MR. ETHIER: Two things. We have significant transmission upgrade, also we have new units coming on line in NEMA/Boston which will probably displace some of the existing units, but there's incremental megawatts coming on line that are very desirable and most importantly the expected incremental cost of those units are about half of the existing units. Those are going to be base load units as opposed to base load units that really run as intermediate capacity because they're so expensive.

CHAIRMAN WOOD: How is the local market power in that populated market? Is that a constrained area? I mean that wonderful HHI you've got, that three-digit HHI, you just want to jump for joy. Does that manifest itself in the area around Boston? What would the local HHI be there?

MR. ETHIER: It would be much, much higher. I don't know that number off the top of my head, although I believe it is in the report that's currently being produced but I would echo Joe's concern that the system-wide HHI, I agree, is an excellent number for New England. But in areas of Connecticut and in NEMA/Boston, those numbers would be far, far higher. We have a congestion management system that takes that into account and explicitly evaluates a number of competitors when we dispatch these units and when we compensate these units. I'd say that's an essential part of our markets is dealing with the local market power that we see there. The advantage of having these new base load units coming in and the transmission upgrades is because you're not going to have that interface being constrained very often if at all arguably it's not going to be as much of a concern because it's going to be part of a larger, unconstrained market. That's the goal here, to get these load pockets integrated into the unconstrained markets so you can have the benefits of the generally competitive marketplace feeding into these local regions.

CHAIRMAN WOOD: What level of transmission upgrade are we talking about going on there? Is there a dollar tag on that?

MR. ETHIER: There is and I don't have it off the top of my head.

CHAIRMAN WOOD: That's of interest, transmission upgrades to facilitate broader competitive markets. It's a pretty good expense of dollars generally.

MR. ETHIER: That's my view.

CHAIRMAN WOOD: Talk to us about Connecticut. We've been having a prayer vigil up here all summer and it's just beginning.

(Laughter.)

CHAIRMAN WOOD: Talk to me in a little bit more detail there.

MR. ETHIER: As I mentioned earlier, we issued the RFP for load response in Connecticut. That's going to provide 83 megawatts that are probably going to be crucial. I think Connecticut should be okay this summer in large part because of that. One really interesting factor that's going to come into play this summer that we didn't have last summer is the cross-sound cable, if that's operating this summer and there are firm energy transactions being exported over Connecticut, that could be problematic. I don't have the completed update on whether or not that's going to be in this summer, but even next summer it'll be really interesting to see how that dynamic plays out. That's just a new wild card in there.

Long Island is highly constrained. From a market perspective, you want to see that balancing between Long Island and Connecticut. From a parochial perspective, I don't want to see that balancing, I want to see Connecticut the lights stay on. It'll be interesting to see how that situation develops, and it'll be interesting to see how the market rules are harmonized across the two regions so that we don't fail to send the same incentives that Long Island does so they can sort of compete equally for that power and that firm energy.

The problem with Connecticut in my understanding is that any significant transmission upgrades have to be major upgrades. In Boston the advantage was there were sort of these incremental upgrades to isolate facilities that would result in greater interface with capacity. My understanding is, in Connecticut, there aren't those sorts of options. You really have to sort of tear down an existing line and double its size probably in a distant corridor to get substantial upgrades in that region. The problems with that are a) it's expensive, b) it's controversial, and 3) it takes a lot of time relative to what we saw in NEMA/Boston.

CHAIRMAN WOOD: And they stopped everything there.

MR. ETHIER: Well there's that. I'd say other than the load response program and the fact that we do not anticipate seeing the same demand levels this summer that we saw last summer because last summer things were very tight in Connecticut. I was talking to our operators, not in the heat of the moment, but just after. Things were extremely close in Connecticut. If we'd had a significant system contingency in that region, we were going to face serious difficulties but that's because of the extreme weather we had. If we are closer to our extended forecast for this summer, we should be okay.

CHAIRMAN WOOD: Have generation pools been showing up here?

MR. ETHIER: Some are. Unfortunately the areas where they are most needed, which are in Southwest Connecticut and Norwalk-Stamford are the hardest places to build arguably in New England. Very wealthy communities, very densely populated so it's hard to site plants and it's quite expensive if you're able to. That's where we haven't seen the investment. In the larger Connecticut region, we have seen some but unfortunately, in part because of our single clearing price system, the incentives haven't been located in the most constrained areas. We've seen generation locate where it's easy to put plants, which is understandable because that's the incentive that developers were facing. Hopefully under the LMP markets, when those get instituted in six or eight months, we're going to see greater locational incentives and we're going to see some building in those most constrained areas where we need to see it.

COMMISSIONER BROWNELL: Are Connecticut consumers seeing the price of the load response program, or is that being shared by the neighbors?

MR. ETHIER: My understanding is that it's currently being shared by the neighbors. That's something that is going to be or currently is an issue in our standard market design filing that is going to come forward so the intermediate term before that becomes in place it's socialized essentially across the entire region, is my understanding.

COMMISSIONER BROWNELL: Can you put a number to that or if you can't today, could you send us that number?

MR. ETHIER: I could tell you today in dollars per kilowatt month for the four months below response. In dollars per megawatt month, it's $45 -- I'm sorry -- a kilowatt month it's $45 a kilowatt month for the four months of the program. We have 83 megawatts. That's a fairly substantial investment in load response in Connecticut and I'm not going to be able to do it in my head right now. But the number gets very large very quickly.

COMMISSIONER BROWNELL: We've got a lot smart people that can do that.

CHAIRMAN WOOD: 45 times 4 times 3 times 1000. We can do that.

COMMISSIONER BROWNELL: If I hear what you're saying, Connecticut has chosen not to build. They can skate through the summer but, my gosh, we've learned from certain other parts of the country that skating through on a wish and a prayer doesn't always work.

CHAIRMAN WOOD: And everybody else is paying for it.

COMMISSIONER BROWNELL: And everybody else is paying for it. The New England ISO has recommended both generation and transmission as well as demand side solutions, is that correct?

MR. ETHIER: Yes. I personally feel we need to allow the response from a range of solutions because that's what it's going to take, and that's probably the efficient response. It certainly is allowing the range to see the price signals and respond to the right incentives. And what we really need to do is move toward providing those incentives and we all acknowledge that our current clearing price system is an impediment to that as well as arguably our socialized uplift payments and so forth. Congestion costs are paid for by all of New England, not just the region.

COMMISSIONER BROWNELL: I think those individual accountabilities may help people think more regionally in the future, at least we would hope. I would hope we could move towards a time where indeed consumers are seeing the cost of their choice so they can make an informed choice which, it seems to me, they can't do now.

Let me just talk about that transmission. You say it's more than upgrade, they'd have to basically replace the whole line. It's not as if there are other options, right? There's been a lot of disinvestment, there's been huge growth, huge demand, so it's not like you have a whole bunch of choices.

MR. ETHIER: That's right. My understanding --

and luckily there's not a system planner sitting next to me to kick me under the table --

COMMISSIONER BROWNELL: Be careful of Anjali, very careful.

(Laughter.)

MR. ETHIER: My understanding of the situation is that there's one primary line that just has to be upgraded and that's the solution for Connecticut to increase the connections to the unconstrained part of the pool. I'm sure there are a lot of local issues and subtleties that need to be upgraded in conjunction with that one upgrade, but there's one big line that needs to be significantly overhauled.

COMMISSIONER BROWNELL: Thanks.

MR. HEDERMAN: Bob, you spoke about new generation. At some point there's been concern about whether existing generation would be available. Do you have a comfort factor on that situation at this point in Southwestern Connecticut?

MR. ETHIER: If the existing generation will continue to be available?

MR. HEDERMAN: Yes.

MR. ETHIER: The ISO is actively working to ensure that it will be. We're hoping that our locational pricing again is going to help and what you'll see coming before the Commission, when we do our standard market design filing, is a market monitoring plan that I believe takes a significant step towards ensuring that we send the right signals to those sorts of areas, these chronically constrained areas. I think the ISO is acting on a number of fronts to send those price signals and to provide those incentives. You know, the important thing I think is that you include -- the market has to work such that incremental units face the same opportunities as potentially new units if you want to keep -- or sorry, existing units if you want to keep those existing units around. So we think we need to treat them comparably. And our plan going forward is to do that.

CHAIRMAN WOOD: The kind of demand side management that's being purchased at 45 bucks a kilowatt month, is it transient or is it permanent reductions?

MR. ETHIER: It's for the four months this summer.

CHAIRMAN WOOD: To buy people to shut off at peak but not to implement long-term demand?

MR. ETHIER: Essentially, yes, and many of those megawatts are actually emergency generators that are being barged in or trucked in or whatever and have essentially temporary interconnections to the system which will be on demand to ISO. It's a hot day, we call you, you turn on, and you know it's load response but it's really demand generation.

CHAIRMAN WOOD: That helps to know that.

MR. ETHIER: Thank you.

CHAIRMAN WOOD: Is the transmission around Boston, is that also spread in the full ISO rate? Is that a PTF?

MR. ETHIER: That's my understanding, but that probably requires a more thorough answer.

CHAIRMAN WOOD: Somebody on our staff I'm sure knows that answer. I just wondered. All right, thank you, Robert, very much.

Anjali?

MS. SHEFFERIN: Good morning, Anjali Shefferin, thank you for the invitation to come and provide an overview of the components of the California electricity markets. I will cover to main areas, first to provide a quick review of the markets we run, and second to address the challenges to reestablishing competitive wholesale markets out west.

(Slide.)

Which involve fixing market fundamentals and structure, redesigning the market rules, which is currently underway an enhancing market monitoring to review on more of a long term and regional basis.

(Slide.)

You have a whole set of slides before you. I'll only go through a subset of those.

(Slide.)

The California ISO has been operating markets for four years. We run essentially three types of markets, a market for reserve services, so we have full markets for acquiring ancillary services which are regulation spin/non-spin and replacement. Participants can either self-provide those reserves or purchase it through our markets.

The second type of market that we run is a market to clear transmission congestion, the third is real time imbalances to make sure in real time demand and supply generation and load are met and finally we don't have a market but we have long-term contracts to meet local reliability requirements that we call reliability must run contracts.

(Slide.)

In terms of the market highlights, I'm happy to report that we've seen a dramatic improvement in the performance of all the California ISOs electricity markets. The trend has been towards stable market prices with adequate supply. And I think if you can go to the next one,

(Slide.)

the average cost of electricity has fallen from a high of

$330 a megawatt hour for every hour of the month at the height of the crisis in December of 2000 down to $41 a megawatt hour, and it's been fairly stable the last three or four months for electricity. Again, this represents the average cost to serve load including the cost of long-term contracts, utility generation, short-term bilateral and real time, so this is all rolled in costs of electricity.

So that is very good news that we've seen prices stabilize.

(Slide.)

In our ancillary service markets, we've seen prices also drop considerably. Last year in 2001 they were five to six percent of energy costs. They have dropped to about two percent of energy costs, again a very good trend.

(Slide.)

Factors contributing to the stable markets have been a near normal hydro year, stable gas prices, healthy level of imports. Conservation efforts by California consumers has also helped tremendously in 2001, and we are hoping that they're going to help us again in the summer, as well as the west wide mitigation across all the states in the west has also helped to stabilize markets.

I do need to mention to you that the market still remains fundamentally frail, even though you see this good performance, your best indicator of future performance is going to be items like reserve margins. You should be looking at what level those are, how much load is covered by long-term contracts, how much is exposed to the spot market. Taking a look again, as the other speakers have mentioned, the expansion of transmission upgrades and lastly, as everyone has said, and I need to echo as well, in a competitive market you need a healthy demand side. So those are the four indicators that we look at to say what's going to be the future health of the market. Unfortunately, we still have some concerns and some work underway. That's why I think the story here is markets have improved dramatically under the west wide mitigation but the factors for a healthy market into the future still probably aren't in place.

CHAIRMAN WOOD: I'm looking on page four, Anjali, at the bottom there. You kind of have a broad phrase and it says "fundamental structural reform" as far as when the reform's needed. You also talk about the market redesign and the extension of the mitigation. What do you mean by fundamental structural reform? What does that specifically mean?

MS. SHEFFERIN: The four items I talked about, the reserve margin, the transmission upgrades, those are really going to be the key indicators of whether your future market is going to perform in a healthy manner and I'll go through where I think each of those factors are.

CHAIRMAN WOOD: Great.

(Slide.)

MS. SHEFFERIN: I won't go through a lot of the individual means of measuring each of our market performance. I'll just point out one on page ten that's our real time imbalance market. Here we look at both prices and volumes in our markets. Prices have been about $54 a megawatt hour in the real time, and the bars give you the volume. As you know in real time you're either inking or decking generation to meet your load. You can see that it's fairly random so that's good. It's not a consistent level of under-scheduling or over-scheduling, so that's a healthy thing.

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There was one day in which we had too much generation, if you can believe it, because of high spring runoff, so we actually had to go out of market and ask people to pay them for the privilege of turning their unit down. That was 5/26.

But, anyway, what I provide here is all the indicators that we take a look at to assess the health of each of the markets. And they are all headed in the right direction, so we're very happy about that. What I would like to turn to is page 21.

(Slide.)

MS. SHEFFERIN: This is the view of overall competitiveness of the market. As Bob Either mentioned, the price/cost markup is the indicator that we use. We have three views of that price/cost markup.

Essentially, because of the long-term contracts that were signed at the height of the crisis, those continue to be part of the rates that people have to pay. So, therefore, you see the markup, which is in the red, continuing to be high, even today.

But, again, that's a reflection of past performance, not as much of future performance, so we do offer two other views of market power. I think the view to take a look at is on page 23.

(Slide.)

MS. SHEFFERIN: This is the markup, looking at short-term energy prices, which will be day-ahead, hour-ahead energy, and real-time. That indicator both gives you a comprehensive view of current conditions, as well as enough volume so that if you brought it down to two short an indicator like the real-time, you might have a lot of volatility.

But, again, the story here on page 23 is that our prices look very, very competitive in our markets. We have come down from the highs of April 2001 when the market was enormous, down to about a five- to six-percent level above competitive levels for system marginal costs.

CHAIRMAN WOOD: Just in kind of layman's terms, how do you calculate the blue?

MS. SHEFFERIN: Sure. It's similar to what Bob mentioned. You essentially do it through a simulation model.

You take a look at the highest-cost unit that should be available to meet demand. So, that unit is not on scheduled maintenance, and it has a standard forced outage, so it's not withholding for its own benefit.

It should normally be available for these conditions. We look at the highest-cost unit to meet the hourly demand.

That is the system marginal cost. Then we look at actual prices, and if actual prices seem to be significantly above that, that gets counted in the pink as a markup.

CHAIRMAN WOOD: So, for example, a gas unit, what would you use for their gas price?

MS. SHEFFERIN: We try to be very conservative in the calculation of competitive benchmarks, so we actually use spot gas prices and spot emission prices. We know that suppliers do much better than that.

Hopefully they do some planning, and they purchase gas a few weeks or a month in advance, so those are much better. But, again, we want to be as conservative as possible.

MR. LARCAMP: How much of the blue is reflected by favorable hydro conditions?

MS. SHEFFERIN: You know, hydro really is not on the margin, but what it helps is, it helps bidders of thermal be competitive in their bids.

MR. LARCAMP: But more hydro takes away the necessity of having the higher-cost unit setting the marginal price.

MS. SHEFFERIN: It does. I also disciplines the bids that those suppliers provide to the markets.

CHAIRMAN WOOD: Mostly because the hydro can show in at the peak hour and give that bid some competition.

MS. SHEFFERIN: Right.

(Slide.)

MS. SHEFFERIN: The last part that I was going to turn to is page 33. Again, what we're doing here is taking those monthly system markups and putting them into a 12-month rolling index.

This is, again, an indicator that we use for overall market performance. Again, I think the positive thing to note to you is, even though on a 12-month basis, which is how have the markets looked on a sustained basis, the high prices drove it up very much during last year.

But with the moderate prices this year, we are seeing that 12-month index fall down, down to what we consider competitive levels. So, again, we try to illustrate that having an index like this gives you a good heads-up in terms of the pulse of the market.

Looking back historically, it's told us when markets were getting out of whack, which was in May and June of 2000, and then again, it's telling us now that markets really have returned to health after a number of months of healthy performance.

If we continue to see the healthy performance that we have the past few months, into the summer -- and we hope we do -- then we can be pretty confident that things are going well. But the summer will tell.

I think that in terms of just the one minute I have remaining, the key structure or issues that help define whether your market will be competitive in the future or not are not looking all that well.

(Slide.)

MS. SHEFFERIN: So we need to monitor it carefully. Reserve margins are up to about ten percent. That's what we expect for 2002, up from five percent in 2000, so that's certainly a healthy direction, but it's not at the level we'd like to see it.

CHAIRMAN WOOD: How does that capture imports to the CALISO service area?

MS. SHEFFERIN: We do assume about 3-4,000 megawatts of imports coming in with those assumptions, with that ten percent. If we have more than that, because the Northwest has surplus hydro, that will help raise it and improve performance in the summer.

If we have less than that, it puts more stress on us. But, again, we remain dependent on imports for 20 percent of our supply.

CHAIRMAN WOOD: Where is all that new gas-fired stuff in Arizona going? Is that factored in here, too?

MS. SHEFFERIN: It is; it's not just from the Northwest. We have two major sources of imports from the southwest and the northwest. In fact, what we've seen is a lot of development of power plants, right outside the California border in the southwest, obviously, so they will have the flexibility of either selling to the southwest or selling to California.

COMMISSIONER BREATHITT: The 20 percent reflects how many megawatts, roughly?

MS. SHEFFERIN: Gosh, we have a peak of about 45,000.

COMMISSIONER BREATHITT: So that number has remained the same for the past several years. I think that in our November 1999 report, we said that the imports were around 8,000 megawatts.

MS. SHEFFERIN: Right, but when the dry year occurred in the northwest, that's when imports fell significantly, and then there wasn't that.

COMMISSIONER BREATHITT: But you're still relying on the same amount of imports that you did several years ago?

MS. SHEFFERIN: In our projections of the ten percent, I think we have it down to about 3-4,000 megawatts.

CHAIRMAN WOOD: To reflect what you really had to deal with last year?

MS. SHEFFERIN: Exactly.

CHAIRMAN WOOD: And the year before. I think that the answer is for their forecasting, they're assuming the last two years, they're not going to get -- that would be their plug. And if they get the extra 5,000 from Arizona and the northwest, that just increases them from ten percent to something else; is that fair to say?

MS. SHEFFERIN: Yes. And we're hoping that it will be a little bit higher.

CHAIRMAN WOOD: The 20 percent was the total import from the outside, right?

COMMISSIONER BREATHITT: That you need to import.

MS. SHEFFERIN: Right. I'm sorry, the 20 percent is on an overall energy basis, and we're talking about the peak day on these reserve margin calculations.

COMMISSIONER BREATHITT: Being what?

CHAIRMAN WOOD: About ten.

MS. SHEFFERIN: Right.

(Slide.)

MS. SHEFFERIN: The second issue of concern is that the investor-owned utilities are not yet creditworthy. Another big indicator of how healthy your market will be is whether the load is being covered through long-term contracts.

Because they are not able to enter into long-term contracts right now, we have some concern as to what will happen when the state stops buying. The utilities start --

we're hoping for a smoother transition, so that they can get in right now and start buying for their needs on a long-term basis, and not have to go back to relying on the spot market.

The third is the demand response. Even though we have a few thousand megawatts of interruptible load in California, there for emergency purposes, we'd like to see more programs just responsive to the real-time price.

Again, that involves metering and working with the state. I believe they have an aggressive program, but it's not much more than we can rely on for the summer.

COMMISSIONER BROWNELL: This may be getting into an area that you don't have any details on, but I thought that there had been a metering program, and a lot of money was spent last summer, so the meters are in place, but not being utilized because there has not been any rate design decision from the CPUC; is that the case?

MS. SHEFFERIN: Yes. We have made the investments, but the rates that you charge people for that metering investment haven't been forthcoming. We've been trying to push for that, because that's critical.

Those few hot days that you have really high prices, there are going to be industries and folks who say, you know what, I can turn down my load for a few hours, and they want that real-time responsiveness.

COMMISSIONER BROWNELL: How much money was spent on those meters; do you know?

MS. SHEFFERIN: It was quite a bit. I don't have it off the top of my head, but I can get that for you, how large that program was.

COMMISSIONER BROWNELL: That would be terrific, and how many meters that are out there that aren't being utilized.

CHAIRMAN WOOD: In order to extend their utilization as a rate design decision.

MS. SHEFFERIN: And lastly, transmission expansion, we have been making tremendous progress in that. We thank the Commission for supporting the upgrade for Path 15. That has been a bottleneck, and resulted in quite a bit of the high prices and exercise of market power in the past.

We also are working on a comprehensive plan to evaluate economic evaluation methodology for transmission projects, and we hope to share that with the Commission soon. We have ourselves and the market survey community working on a new way to evaluate the benefits of transmission upgrades.

And we're hoping that the California Public Utilities Commission works with us on that and adopts that process, and that will help further facilitate transmission upgrades.

CHAIRMAN WOOD: I'm sorry, you said you all are working with the other parts of the West on that analysis?

MS. SHEFFERIN: California is holding a stakeholder group meeting on that analysis. We're going to share it with the California Public Utilities Commission, hoping that they will adopt a standard methodology, so you don't have to start from ground zero on every transmission project, if there is a standard methodology for evaluating those.

Lastly, we are again asking for continuation of the west-wide market power mitigation and the view that markets in the west are very much interconnected, and the regional look has to be put in place for effective market monitoring.

(Slide.)

MS. SHEFFERIN: Of course, we're working with you all on the examination of the Enron-type trading tactics. We are trying to provide all the information to you. We're analyzing it ourselves and sharing that with you.

But keep in mind that a lot of those gaming strategies had to do with the congestion management and ancillary service markets. They are a relatively small portion of the market, and the bigger concern, of course, is mitigation of market power, and I think that's where we're trying to spend our efforts. Thank you.

CHAIRMAN WOOD: Thank you, and thanks for the data and putting the data in context. That was in the pages we skipped over.

COMMISSIONER BROWNELL: I know that you, indeed, have been sharing information with our market monitoring folks who are doing the investigation. Are people sharing it with you? You have a whole bunch of investigations going on, I think, that the CPUC is conducting on outages, and your legislature is conducting at least one, I think, or your Attorney General.

Are they giving information to you as the market monitor who is responsible for that?

MS. SHEFFERIN: It tends to be the data source. And they have the subpoena power. They're not sharing with us, the information that they are getting through their subpoena power.

But certainly, as questions come up on how to analyze the data. We're provided the full amount of data on the market transactions to them, all those parties as questions come up.

But we don't have any subpoena power, and all those agencies do, so I think they have much more information than we do to evaluate these incidences.

COMMISSIONER BROWNELL: So that works two ways: You don't have the information they have; they might ask you to analyze data, which you are doing in a vacuum, because you can't validate the other data that they have that you don't see.

MS. SHEFFERIN: I think the way it works is that through their subpoena power, they will say, take a look at what happened on such and such a day. The claim is that this happened; can you verify that? And then we'll go and verify it for them.

COMMISSIONER BROWNELL: Or not, because you don't have the data they have.

MS. SHEFFERIN: Right.

CHAIRMAN WOOD: I noticed and read on the last page there, "need region-wide monitoring to identify some strategies."

Let's kind of think in the big picture. We've certainly got the three western RTOs proposals for the summer to deal with. You've been doing this for awhile and you've got some thoughts on it.

And this also has applicability to our eastern markets, since we're trying to integrate an approach to market monitoring there as well. What kind of broad contours do you need for a multi-region market monitoring unit to be potent, timely, and effective?

MS. SHEFFERIN: I think the Enron memo showed us that these markets are very much interconnected, and the transactions that are conducted occur not just within one market, but across all these markets. So, the west is looking at establishing a west-wide monitoring effort, really even prior to even the RTOs starting out, because I think that people see that they're being impacted by those strategies right now, today.

So, we're trying to form a coalition and share some data, but right now, it's very much in the infant stage of even what would a structure look like for regional market monitoring? How would it be conducted?

I think right now it's going to start off with everyone sharing their expertise on an ad hoc basis, and then perhaps later, a more formalized structure would be set up. But it's really in infancy, but I really do believe the Enron memo showed us that a lot of transactions occur outside your boundaries, and yet they affect you, so you need that information, not within one state.

The other thing to keep in mind is E-tagging of resources across states is going to be very important, and to the extent that the different control areas share their information on E-tagging --

CHAIRMAN WOOD: Is that being done now in the western market?

MS. SHEFFERIN: Right now, it's really informal communication between control areas, and I think it really can be formalized more.

COMMISSIONER BREATHITT: Is the one trading practice -- well, it strikes me that the one trading practice that does have regional implications, perhaps more than the others, was the megawatt-bouncing, or ricocheting.

MS. SHEFFERIN: Right. And, again, your west-wide price cap helped that. I think that also is mirrored in what my fellow market monitor said. One capacity price across the region, otherwise people are just going to go shop.

COMMISSIONER BREATHITT: Were there others that had regional implications as much as that one?

MS. SHEFFERIN: Yes, there was the circulating power flow, where each control area said it was just a wheel-through, but it turned out to be a wheel-through for everybody, and there never really was any power at all.

COMMISSIONER BREATHITT: The wash.

CHAIRMAN WOOD: What was that one labeled?

MS. SHEFFERIN: Death Star, circulating power, Death Star.

CHAIRMAN WOOD: I've seen Star Wars, since that memo came out, and I fail to see how Death Star accounts for that. All the other ones make sense.

MS. SHEFFERIN: Like Fat Boy.

(Laughter.)

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MR. HEDERMAN: I had one question on page 16, addressing the must-offer, and outage management in terms of the effect on outages. Have you assessed their effect on prices as well?

MS. SHEFFERIN: Again, I think there are two things that were done: One, just that people have to report forced outages. They didn't have to do that previously. I think that helped tremendously.

Then the must-offer really allows the system operator to manage the system and give waivers. What we call the economic outages, did waivers when we don't think that the system reliability is going to be threatened, so we do feel that the must-offers helped tremendously.

MR. HEDERMAN: Thanks.

MR. PATTON: Good morning. By way of introduction, let me explain the relationship between myself -- I'm the independent market advisor for ISO New England and for the New York ISO, and work with them on the market monitoring. We're an independent entity and each ISO has an internal monitoring function.

Steve Balser heads the market monitoring unit for the New York ISO and is the counterpart of Bobby Darrin in New England.

What I will be presenting today is the annual report we have done for New York, but I'm happy to answer questions regarding either market.

(Slide.)

MR. PATTON: Starting off, I would say that the overall conclusion of this report is that the markets have been very competitive in New York and have operated very well. And I think that, in a very real sense, it validates the policy direction the Commission is going on in standard market design.

(Slide.)

MR. PATTON: Many of the elements of the New York market are consistent with the early policy direction on standard market design related to ancillary services and locational pricing in multi-settlement systems.

As far as what I'll be talking about, it's basically what happened. I won't have much time to say why, but I'm happy to stop and answer questions.

As far as the general trends in the energy market, what the first graph shows is that energy prices were driven up substantially in 2000, largely by fuel prices. Prices rose between January and December, something like 75 percent. Natural gas prices rose to astronomical levels by the end of 2000, with oil prices rising in a less dramatic way, but also rising significantly.

(Slide.)

MR. PATTON: What happened in 2001 was almost exactly the opposite. Natural gas prices and oil prices fell, as did electric prices, by roughly 50 percent from January to December, which is what you would expect.

The other thing this graph shows is the differences between the prices in eastern New York and western New York, which indicates the amount of congestion on the primary path across New York.

The congestion fell by roughly 40 percent from 2000 to 2001, and you can see that it's particularly pronounced in the summertime. The reasons for that were that fuel prices dropped. Oil and gas is almost always the marginal fuel in eastern New York, and is often as not in western New York.

But, secondly, the return of the Indian Point II nuclear unit, which is a thousand megawatts in eastern New York, played a tremendous role in alleviating the congestion across the state.

CHAIRMAN WOOD: Who is the operator of Indian Point?

MR. PATTON: It was ConEd. It's now been sold. There are actually two Indian Point plants that total two gigawatts in eastern New York.

There has been some controversy about the Indian Point plants since September 11th, related to security concerns. But because they are on all the time, and they are located in a most constrained part of the state, outside New York City, but otherwise, they are located in eastern New York, which is capacity-constrained.

They play a vital role in the energy market.

COMMISSIONER BROWNELL: David, on that point, I've seen some estimates of the costs to consumers, if you took out Indian Point. Can you give me a number, just approximate? I think it's important for consumers, once again, to understand that they've got choices, and what those choices cost.

MR. PATTON: Sure. The prices -- we actually dwell on this in 2000, because 2000 was the first year of market operation, and prices in 2000 were substantially higher than what people had expected and what they had seen in '99.

The concern was that the ISO market really lead to much higher costs and were operating inefficiently. So we had done an analysis of how big a role Indian Point, a single unit being out, which obviously is only half of the capability, played in that.

And I think that in the summertime, it accounted for something like 20 percent of the price increase. It's important to note, though, that the price effects of taking capacity out are not linear.

If I say prices went up by 20 percent with one out, it doesn't mean that they would be 40 percent higher with two out, given the shape of the supply curve and the importance of the shortage prices that get set under capacity shortages.

What happens when you start taking capacity out is that you go from five hours of price spikes or shortage, to maybe, with one out, to 15, and maybe with two out, you go to 50. It accelerates.

I've seen statements that suggest that there wouldn't be a significant economic effect to taking those out, and I'd be happy to quantify what that effect would be, and that it would be a significant economic effect.

(Slide.)

MR. PATTON: As far as the next chart in the Executive Summary, one thing that is important in these markets is price certainty. One important statistic that will indicate the degree to which price certainty exists in these markets, or the degree to which it's undermined, is the level of price corrections that occur after the fact.

What I show here is 2000, through early 2002. What we saw in 2000 was significant price corrections on the order of three percent of the real-time intervals, corrected largely due to software issues. That fell to about .4 percent in 2001, with the vast majority happening in May.

Actually, most of it happened in the first four days in May when the new software change was put in place. That created some errors that had to be corrected.

In 2002, it has fallen to .2 percent. It's never going to go to zero, because you're always going to have input errors and metering errors that will create prices that are wrong, that need to be corrected.

But the goal is to get that to the minimum, and to correct them as quickly as possible after the fact. Usually, I think it takes roughly two days.

(Slide.)

MR. PATTON: The next chart, I think, is an important chart from the perspective of analyzing how these markets have performed in terms of their competitiveness. Bob alluded to a report that we did for New England that was quite a bit more detailed than what you will see in the annual report here.

But the notion here is that any measure you employ to look for withholding is naturally going to identify conduct that could be anticompetitive, as well as conduct that is justified. There is no way of perfectly separating the two.

The example in this chart would be outages or deratings. Every market, even perfectly competitive markets, are going to have forced outages, and they're going to have deratings.

And the question is, do the patterns of those deratings coincide with evidence of market power abuse? And so while you would want to look at the overall level of deratings, what is more interesting to look at is how they vary under different market conditions.

When you're away from the peak, the markets provide a powerful competitive signal, because no one supplier can have a significant effect on prices. When you get to peak, though, the large suppliers, if they withhold, can drive you into shortage conditions, so you want to look at how behavior changes when you get into the very peak hours, versus the behavior in other hours.

And what this shows is that generally the behavior has been consistent with what you expect in workably-competitive markets. That is that suppliers attempt to minimize their deratings in peak conditions, and get as much supply into the market as they can to earn the high prices.

(Slide.)

MR. PATTON: This is perhaps the ugliest graphic in the annual report, and it's ugly for a couple of reasons: One, because it's not very attractive; but, two, because it reveals probably the worst economic problem that New York had in 2001.

When we talk about price convergence, whether it's day-ahead to real-time, or, in this, case, the hour-ahead scheduling model to real-time, it's a yawner, because it's hard for people to intuit why this is important.

Why it's important is that each of these models, whether it's the day-ahead versus the real-time, or the hour-ahead, is making economic decisions that have real implications.

The day-ahead, for example, is deciding what units to turn on. If you make a bad decision on what units you ought to be turning on, you're going to end up with inefficiencies, both in the day-ahead and in real-time.

In the hour-ahead, the decision that's being made is what external contracts to schedule and for those generators that can't change their dispatch every five minutes, where they ought to be for the next hour. You can see that in New York City, when you got into the peak conditions, you almost never had the hour-ahead model making the same pricing decision as the real-time. In fact, they were often a thousand dollars different, which means that you're making really bad decisions at that point about scheduling external contracts and dispatching the off-dispatch generators.

What that leads to is generally depressed prices in the real-time, which is what people actually use to settle on. So, it's sending a bad signal to the generators, and it leads to substantial uplift, because you've got to pay for these decisions you have made.

If you took an expensive import, you then have to pay them, and it comes out of uplift.

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Two critical changes have been made in early 2002 to bring convergence between the hour ahead and real time as well as changes to how New York's internal transmission inside New York City is modeled to reflect the constraints inside New York City which had previously been managed without merit dispatch, again leading to distorted real time prices and uplift.

(Slide.)

The next chart provides a list of various seams improvements that have been made. Given your session two weeks ago, why don't I move over that because this largely would be repetitive with the report you've just received from the ISOs.

(Slide.)

Going on to the two areas that in my mind still are significant issues that need to be addressed. First are ancillary services. The chart on ancillary services shows that for 30-minute reserves in regulation, we generally get less than half the capability bidding into those markets. This is usually not a problem. Ancillary service costs, by the way, run about two percent of the total market costs so again this is an area that's hard to get people interested in. The issue really relates to the energy market because the amount that is offered into these markets is well above the demand level that we typically need. The prices usually are reasonable. The problem is that under peak conditions, the ancillary service markets are competing against the energy market, and you can get yourself into a shortage of ancillary services and you can make inefficient tradeoffs which can lead to price spikes that shouldn't have happened in both energy and ancillary service markets.

Now the recommendation I have for addressing this is, this is an incentive problem in those two markets recommending reforms to how we price ancillary services to ensure that the price is always covering the opportunity costs of the resources that are pulled out of the energy market to provide reserves. Second, I'm suggesting a multi-settlement system for reserves that would be very similar to energy and third recommending a demand curve be implemented for ancillary services.

We talk a lot about demand participation in the energy market. One area that is perhaps a low-hanging fruit from the perspective of getting good price signals in energy is establishing a demand curve for reserves that would allow the pricing in the energy markets to reflect when you're moving into shortage capacity shortages. Lastly, the capacity markets. One thing I would say about the capacity market is that statewide the performance of the capacity market was what you would expect that when we were tight in the capacity market, we set relatively high prices, in fact prices comparable to the prices in PJM. But we got some capacity surplus in the winter period and the capacity prices went way down.

We have one unique feature in New York which is locational capacity in New York City which I think is, in theory, a great idea because it sends a signal where you need the capacity, and it would be a great idea for Southwest Connecticut. The problem is you have fewer suppliers. They're larger in relation to the demand and what we saw happen in New York City was that when some capacity surplus emerged in the winter time, the prices didn't fall to where you would expect they would fall to because the suppliers knew if they simply didn't provide capacity, they could keep prices relatively high in New York City. So it's a problem that I've recommended that we look at market rules related to capacity that would mitigate that phenomenon, and I agree with Joe, that it would be very beneficial to synchronize the capacity markets in neighboring RTOs. In fact, there's a working group to do that in the northeast so I'm very supportive of that effort.

(Pause.)

CHAIRMAN WOOD: The scatter shot graph, I've gotten distracted. Walk me back through again what we're to make of this.

MR. PATTON: Okay. I'll give you an example.

What this is showing you is the hourly price difference between what the hour ahead scheduling model, which is called a BME in New York, which schedules your external transactions because they have to be scheduled ahead of time, and it sends a dispatch signal to the generators that are off dispatch, the ones that can't change their dispatch every five minutes. So it's the difference between the price produced by that model and the price produced by the real time model that's setting real time energy prices. What you see when you're down at moderate load levels is the vast majority of the prices are pretty close to zero, the price differences. That means when you're deciding whether to take an import from New England and the import is available to you at $50, you're making an accurate tradeoff. You're saying well, my model tells me power is worth $70. Therefore I'm going to schedule this import.

What happens when you get to the peak times is because there were differences in how reserves were treated, and this happens to be New York City, so it reflects some transmission congestion related differences that aren't shown in the eastern chart that's later in the package.

But what happened in the peak conditions is you'd get a much different price condition in the hourly scheduling. Let's say you had an import from New England that was being offered at $1,000. The model would take that import, even though it wasn't economic. You then would have obligated yourself to pay that importer $1,000 which would come straight out of uplift, and you'd have too much supply in the real time which would depress prices in the real time. It's one of those unique issues where everyone's getting hurt. The loads are getting hurt by having to pay high uplift. The generators are getting hurt by being paid low energy costs. So it was easy to build a consensus around getting this fixed quickly. In fact, your order at the end of May allowed us to put the changes in to address this problem.

CHAIRMAN WOOD: Thanks. Questions for David or Steve on New York? Bill?

MR. HEDERMAN: I have one question regarding the bilateral contract information. What stimulated it was you had some graphs with the physical quantities, if you will. This is a question that I'd like anyone else to chime in on as well. Is there other information about bilateral transactions that you really wish you had better access to?

MR. PATTON: I know Joe and I aren't going to completely agree. One caution on the graphic you saw, New York allows scheduling of what they call physical bilaterals, which means that the commodity is not settled through the New York market, you just tell the New York ISO you're going to put power in at A, take it out at B. They charge you a congestion charge and you're done. That's not the extent of bilateral contracting because there are financial bilateral contracts that are settled through the ISO, so people have frequently been concerned that the physical bilateral numbers at 50 percent and assumes that only half the power is in bilateral contracts in New York which is clearly not the case. The information that I think would be useful is to know quantities of the other bilaterals so that you can make an assessment to the extent to which loads are exposed to the prices in the ISO markets.

And there is one particular type of bilateral contract that's critical for market monitoring in my opinion, and those are contracts that give a different participant the authority to bid or control a unit because if you don't know that, you could potentially be missing coordinated strategies where you have a participant who is bidding more resources than they owned. So that's important to be aware of in judging the conduct that you're seeing.

MR. HEDERMAN: Anyone else?

MS. SHEFFERIN: I think we've been generally talking and the market monitors would appreciate some more information on the bilateral. Right now in California, we get it just because the state is doing the buy-in. They share that information with us 45 days afterwards, and then we can only guess on the other portion of the market.

CHAIRMAN WOOD: Has that information been beneficial? Is 90 days too late?

MS. SHEFFERIN: Ninety days is really too late because a lot can happen in markets.

CHAIRMAN WOOD: Good point.

MR. LARCAMP: You need that information from non-public utility sellers as well to get a good picture.

MR. HEDERMAN: Shall we move on to AEP then? Doug?

MR. BOHI: Thank you, Commissioners. I'm Doug Bohi with Charles River Associates here in Washington. For the past two years I've been serving as the market monitor for AEP. During that period I've been making regular quarterly reports to the Commission.

(Slide.)

As Bill indicated at the beginning, my job has been a bit different from my colleagues here at the table because AEP of course has no independent system operator and no organized centralized markets for energy and ancillary services, and therefore

(Slide.)

this was a requirement imposed on the merger of AEP and the CSW a couple of years ago in which it said that interim market monitoring is required until AEP joins a FERC accepted RTO. Actually, it's a little more than that. It's that it must transfer control over its transmission assets to a FERC accepted RTO. The purpose in the order of monitoring was to determine whether AEP creates transmission congestion in order to limit competition in the wholesale market and to take advantage of that limited competition. The second purpose was to respond to complaints from third parties in the area about AEP, and to respond to requests for additional studies of the market and market conditions, particularly requests that would come from FERC itself.

The concern about AEP creating transmission congestion focused on AEP's generation dispatch patterns and also on whether or not outages of other transmission facilities might exacerbate congestion.

(Slide.)

The next slide, the measures of transmission congestion that I use which in fact trigger what data I collect and for what time periods and what parts of the system are TLRs, transmission loading relief, with special emphasis on periods when curtailments of existing service occur. Pretty much the only curtailments that have occurred over the last two years have been for non-firm service. The couple of occasions when firm service was curtailed, it involved pumping for generations storage plants, generating plants in which pumping is required for storage, particularly in Virginia Electric Power's Bath County storage facility.

Normally you would think, and in fact it is the case that when your TLRs that affect certain customers that those customers are also the ones that are affected most by refusals of transmission service, meaning that they have the highest rates of refusal based on their requests, and the highest numbers of refusals.

(Slide.)

The next slide shows a map of the AEP system.

(Slide.)

If you have good eyes, you might be able to make out that not only are there transmission lines on this map, but some generating plants as well. The area that is perennially affected by congestion on the transmission system is the corridor in which power is transmitted from AEP to the Southeast, namely the states of Virginia, North Carolina, and Tennessee. Virtually every month in the past two years, this has been, this corridor has been congested on occasion. During the summers, we've had some congestion in the corridor that interconnects AEP with Michigan. That, as I say, only has occurred in the summers. They have recently put in place a new transmission facility that increases the transfer capability by some 2,000 megawatts into Michigan, so this summer may be different than the past two summers. Otherwise, congestion has been very rare and sporadic in the AEP system. It's really the focus of attention on that corridor that connects AEP with CERC that affects the ability of folks in the midwest and north to transfer across the AEP system into the southeast.

(Slide.)

The next slide shows how AEP compares with other transmission customers for using the AEP transmission system. What I have here is a measure of the rate at which transmission requests are refused, refusal rates, measured a couple of different ways how these compare, as to how you measure them. The points of delivery that is to customers that are affected by these refusal rates are California Power & Light, Duke, TVA and Virginia Power. Those are of course the control areas that connect with AEP at the end of that congested corridor I just got through talking about.

I also compare hourly refusal rates with daily refusal rates, that is to say requests for hourly service that are refused or requests for daily service that are refused. Generally speaking, AEP's refusal rates are lower than other transmission customers, although for hourly they're both very small and in some cases not very different. For daily service, depending on how you measure the refusal rate, you could come to the conclusion that AEP's is always less than other transmission customers.

Although in the bottom table, you can see that for Duke as a delivery point, AEP's refusal rate's actually higher than that of other transmission customers.

COMMISSIONER BREATHITT: Mr. Bohi, is refusal rate another word for curtailment or you don't have the capacity to schedule? What do you mean by refusal?

MR. BOHI: Curtailment refers to existing service that's taking place and whether you cut it back. That's where the TLRs come in. Refusals of new service are when folks go in to make a request for new service, whether or not they can get it. This is the rate at which those requests are turned down.

CHAIRMAN WOOD: Tell me what I'm to make of this.

MR. BOHI: It's in the eyes of the beholder.

CHAIRMAN WOOD: You're my beholder.

(Laughter.)

MR. BOHI: Generally speaking, as I said, AEP's refusal rates are less than other transmission customers. Whether or not that means they're getting preferential treatment and access is not absolutely clear. As I say, some of the numbers are not very different and they could be explained by just having more knowledgeable traders, folks who know more about --

CHAIRMAN WOOD: This is showing -- let's take the Duke column. What this is saying, let's use the both. Is the both kind of a composite of the hourly and daily?

MR. BOHI: Yes. That is the sum of refusals for hourly and daily.

CHAIRMAN WOOD: Let's just say using both. This is saying that the refusal rates of AEP's transmission system to AEP generator or marketer usage is 15, what is that, percent?

MR. BOHI: Yes.

CHAIRMAN WOOD: Do the Duke line. Whereas if someone other than AEP came into use it, it would be 41 percent?

MR. BOHI: That's correct.

CHAIRMAN WOOD: I don't want to jump to a conclusion here but tell me why I shouldn't.

MR. BOHI: Look to the table below it for Duke as well. You can see that the refusal rate for hourly service is 5.1 for AEP and 6.1 for everybody else, not very different. In other words, as a matter of fact most of the requests and most of the refusals have to do with hourly service rather than daily service, so right away you can see it's not all that different. Also you can see for daily services, you can see that AEP's is actually larger than other folks.

CHAIRMAN WOOD: Say that last part again.

MR. BOHI: For daily service in the bottom table, AEP's refusal rate for daily service is 33.7 and it's 31.6

for all the other transmission customers.

CHAIRMAN WOOD: Why has the "both" got the big spread again?

MR. BOHI: That's a combination of the fact that most of the members are in hourly but that other transmission customers request daily service proportionately more than AEP does.

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CHAIRMAN WOOD: Due to the day ahead schedule?

MR. BOHI: Yes.

CHAIRMAN WOOD: Is the top box or the better box a better box, that's retracted and withdrawn?

MR. BOHI: I tend to look at them as bracketing what the true refusal rate is. The bottom one includes in the denominator retracted and withdrawn. These are requests for service that were initially approved, but then either were withdrawn by the customer or the customer didn't act on it in the required amount of time, and it was retracted by SPP.

The reason that's probably a lower number than the true number is because even though they were approved, these retracted and withdrawn requests, they go back in the pool and somebody else can then get access to transmission service using that capacity, which wouldn't have been able to if in fact they were confirmed. So it probably overstates the amount of acceptances, confirmations.

CHAIRMAN WOOD: What other types of analysis did you consider before deciding to use these as a method to ascertain comparability of treatment?

MR. BOHI: Other measures?

CHAIRMAN WOOD: What would you do other than this that would be any more instructive, or is this really --

MR. BOHI: FOr requests for new service, this is what I've ended up with, yes.

CHAIRMAN WOOD: It doesn't look real great.

MR. BOHI: The next slide, if I should go on to it or not.

(Slide.)

CHAIRMAN WOOD: Please do.

MR. BOHI: Talks about AEP's wholesale prices in markets that are affected by congestion. Do they rise if flowgates are congested on the corridors that serve those markets? Usually, they do, although not always. There are times when those markets have options for supplies that don't come through the AEP system, in which case those prices aren't so affected. But usually, they do rise.

Do they rise in those markets by more than market hub indexes that are published by, say, Power Markets Week, which reflect not only transactions by AEP, but by other sellers in those market areas as well? And no, they usually don't. They're usually lower than the market hub prices. Essentially, you could say that AEP is leaving some money on the table by not charging as high prices as other people.

I use the AEP price information to focus on time periods in which I want to examine further the prices that are highest during the quarter in these market areas or that have increased the most from a noncongested time period to a congested time period or the time periods and events that

I'm going to focus on as to whether or not AEP's operation of its generation and other parts of the transmission system have affected congestion.

(Slide.)

MR. BOHI: On the next slide, as far as the effect of AEP generation dispatch on congestion, what I use are generation shift response factors to measure the contribution of every generating unit in the AEP system on congestion on a specific flowgate that's suffering from a problem.

I then correlate the rank order of operating rates of those generating units with the rank order of the GSRFs to see whether or not the way those generating units are being operated correlates with the congestion that's occurring on a particular flowgate in a particular hour in which the prices have led me to believe I should look more carefully.

So this is an hour-by-hour set of rank correlations that I performed during the quarter. So far, there has been no correlation between its generation dispatch and its congestion. To me, that would indicate that it has not been operating its system in a way to exacerbate the congestion.

If I had found a significant correlation, I would have turned to the next question, which is whether the rank order of those operating rates is consistent with economic merit order because you could want to run your units in a way that saves your customers the most money if you don't exacerbate congestion problems for someone else. There's a tradeoff between economics and congestion sometimes.

The next slide address the question of the effect of transmission outages on congestion.

(Slide.)

MR. BOHI: Here I look at whether there are outages on other parts of the transmission system during the times in which there is congestion, high prices and curtailments and so forth. It turns out that seldom is there a coincidence between the outages of other transmission facilities and the congestion problems that have been identified.

If there were, then I ask the question whether those outages could significantly contribute to flows across the congested facilities, in which case I use outage transfer distribution factors which in fact convey that information. When that has occurred, the contribution to flows has always been less than 3 percent, indicating that it hasn't been a very important contributor to those.

(Slide.)

MR. BOHI: The last slide addresses the question of one of my other responsibilities, which is to respond to complaints or requests for additional studies. In the past two years, there have been no complaints, at least that have been forwarded to me, and there have been no requests for additional studies.

Thank you.

CHAIRMAN WOOD: Thank you. Bill?

MR. HEDERMAN: I just have one question on the last page, Doug. Is that a good thing or a bad thing?

(Laughter.)

MR. BOHI: It hasn't kept me very busy, so in that sense it's bad I guess.

MR. HEDERMAN: Is your sense that people know of your function and how to reach you and no one's complaining?

MR. BOHI: Well, I know at the time that AEP submitted its compliance plan for market monitoring, there was a lot of reaction from intervenors in the case who were third parties in the area who all had comments about the market monitoring plan and how it was going to be conducted. So I assume that they were well aware of this opportunity.

MR. HEDERMAN: Okay. That completes the monitoring presentation. Any other questions?

COMMISSIONER BROWNELL: Bill, I'd just like to make a recommendation, something that you and I talked about. You might suggest I've even harped about it. But as you develop your report card or measurement system for the

RTOs, I think it would be helpful if we developed a standardized reporting format for at least some of the key indicators for the market monitors so we can get a better understanding of how things work and send things to different markets.

As you saw from our questions on the last charts, I think we need a little coaching. So if we see it in the same format, maybe we won't need so much coaching, and sooner rather than later. Thank you.

CHAIRMAN WOOD: I want to thank all of you all, not only for coming today, which we appreciate, but for what you do on a day-to-day basis. You're the front line for what this agency takes very seriously as its role in making sure markets produce just and reasonable outcomes for the customer. We are indebted to you for the body of knowledge you bring, the long relationship you've had with a lot of the unheralded members of our staff who actually have been doing this job well for a long time, but now I think have the added bonus of knowing that their three, four, and one day soon, five bosses care about this very seriously. It's a core part of our mission, too.

So, thanks for being the front line and for the kind of data that you give that helps make us smarter in what we do. And we want to continue to back and support your efforts. Please always feel free, as Joe mentioned in his order, and we'll be putting it in all the rest of them if they're not there already, you all have a direct line of communication in this agency. There is no editor or vetoer or diverter of whatever data you've got or issues you have to bring up with us. This man is your touchpoint, but we're right there behind him. But always know that we care deeply about what goes on, and the sooner we know it, the better. Thank you for coming. We'll invite you back. We'll try to probably segment these so we can spend more time on individuals. But thank you for being our first one together. Because I think one of the nice things of seeing a bunch of different presentations is there are real useful and good aspects of each that may make the request an easy one to satisfy, because they all aren't.

(Laughter.)

CHAIRMAN WOOD: Nora, do you have any thoughts?

COMMISSIONER BROWNELL: Certainly the role of market monitors and our market monitoring staff is obviously more important today than it ever has been before, but there are lots of people in the building who have been doing a tremendous job and who under I think extraordinarily trying circumstances last year and before that, produced a gazillion orders, gave us good information and worked very hard every day.

I want to remind us all that we have a great team here. Frankly, you should hold us accountable, because it's all about leadership, and hopefully, we are providing that. But thanks to the people whom we never see at the table. Thanks.

CHAIRMAN WOOD: We will break for about 15 minutes to go get paper for the next presentation. Why don't we just say a little before one, about five minutes to one? Let's have the next folks here for the alliance issues.

(Recess.)

CHAIRMAN WOOD: Welcome back. We'll go back on the record.

Sheldon, is this yours to run or Cindy?

(No response.)

CHAIRMAN WOOD: Then it's mine to run. Welcome.

(Laughter.)

CHAIRMAN WOOD: Time to seize control. I think the plan was to go from east to west as the sun goes. I think we're all seated in that general direction, so why don't we start that way? I guess this is a general inquiry from us. I appreciate you all coming to the Commission today to visit with us about the Alliance Company choices. Why did you choose what you chose? What went into that decision? What considerations are important to you as a member company in making this voluntary decision? And what else do we need to know about the configuration issues that have not come forth and gotten in our record as of yet?

MR. STATON: Good afternoon. I am Jimmy Staton, the Senior Vice President of Electric Distribution and Electric Transmission for Dominion. Let me start by telling you a little bit about Dominion if I could. This will be the commercial aspect of the presentation.

Headquartered in Richmond, Dominion is one of the nation's largest producers of energy. We have production capability of more than 3 trillion Btus of energy per day. Dominion's 22,000 megawatt generation portfolio is expected to grow to more than 26,000 megawatts by 2005.

In addition to the more than 4.9 trillion cubic feet equivalent of natural gas reserves, and more than 450 billion cubic feet equivalent of annual production, Dominion also owns and operates 6,000 miles of electric transmission lines and 7,600 miles of natural gas transmission lines. We operate the nation's largest underground storage system, and we serve nearly 4 million retail natural gas and electric customers in five states.

Again, that was the commercial bit about Dominion. Let me now talk a little bit about RTO development. Dominion wants to commend the Commission for your efforts to develop a standard market design. We continue to support the Commission's efforts to form regional transmission organizations. Dominion believes that properly functioning RTOs will provide many benefits and will promote robust wholesale competition.

Specifically, we see RTOs as meeting three goals: Improved price signals to consumers and suppliers, efficient solutions for transmission congestion management, and a robust wholesale market that develops a strong foundation for emerging retail markets.

A little more specific for today's topic, Dominion announced yesterday that we are pursuing an agreement to have our 6,000 miles of transmission lines operated on a regional basis by the PJM interconnection. We believe that PJM is well on its way to achieving the three goals just previously mentioned.

Under the terms of our agreement with PJM, Dominion would establish PJM South, which will be similar to the newly established PJM West and would allow Dominion's control area to be operated separately under the single PJM energy market. Dominion and PJM are working diligently to finalize the specifics of that agreement. Our decision to join PJM was based on very careful consideration of a number of key factors, including input from our state and federal regulators, wholesale and retail power customers, and other interested parties.

The established wholesale electricity market that

PJM oversees is the best RTO option for us in terms of Dominion's operational characteristics, three key measures pointed us towards PJM: Number one, the physical characteristics of our system. Dominion's tie line capacity to the North and West which currently interconnect with PJM, represents 78 percent of the company's total tie line capacity.

Additionally, secondly, the natural market flow for the Dominion Virginia Power system, our total metered energy interchange to the northern part and the western part of our system, represents 93 percent of our total interchange levels.

Then thirdly, from a reliability perspective, PJM was the right choice. Dominion's historical operating issues and concerns lie around our North and West interfaces. Widening the PJM market to include those interfaces will improve reliability in the region, even more so if other planned PJM additions actually happen.

Yesterday was a significant step for Dominion, but it was just an initial part of the RTO process. Over the coming months we look forward to working with the Commission in gaining the approvals necessary to permit Dominion to become a member of PJM.

Thank you for your time today.

CHAIRMAN WOOD: What steps are required in what you agreed on yesterday with PJM to effectuate -- what kind of timetable are you talking about being under their energy market rules, et cetera?

MR. STATON: Initially, we set a timeframe for ourselves of 120 days to reach final agreements and to come up with an implementation plan. We expect to be able to do that within that timeframe, hopefully sooner than that, which will get us into the fall. If everything goes well, the actual timing of implementation could be impacted by some of the other participants at today's meeting. But generally, we think by the second quarter of next year, we should be in a position to be up and operating as part of the PJM group.

CHAIRMAN WOOD: By that you mean actually operating under the market rules and market oversight of their energy market? You're a participant in that?

MR. STATON: The control of the transmission assets would be the first step. That's probably early in 2003. The market may be a little bit later in 2003.

CHAIRMAN WOOD: I noticed in both your opening statement and in the press coverage of Dominion's selection yesterday the need to have a separate control area. What's your thinking on that? Is that just practical or is that the way it's going to be for forever?

MR. STATON: I think it's more of a practical consideration for our customer, from a customer perspective and from the perspective of our state commissions, to continue to operate with a separate control area. Whether that continues forever is probably the subject of discussion.

COMMISSIONER BROWNELL: Could you elaborate a little more? What's the value added there? I mean, your state commission, while it's always a good idea to listen, but why?

MR. STATON: I think it's a matter of transition more than it would be anything else. It's just the idea of moving into an entirely different market environment and a regulatory environment is something that we're not sure we're as comfortable with, and we don't know that the state commissions in North Carolina and Virginia would be comfortable as well.

But again, whether that's something that continues on indefinitely is not something we've necessarily talked a lot about.

CHAIRMAN WOOD: Thank you. Mr. Baker?

MR. BAKER: Mr. Chairman, if you'd just indulge me just for a minute to talk about one other thing. I was in the audience when Mr. Bohi gave his report on the market monitoring, and there were some questions raised about the refusal rate of transmission reservation requests, relative

AEP requests versus other parties.

I just wanted to make sure and remind the Commission that in the area of transmission, there were two conditions in our merger. One was setting up a separate market monitor. The other one was that we had to outsource the refusal of acceptance of transmission reservations to an independent third party. The party who does that for us is SPP. As a matter of fact, there are people here who represent them.

The other thing I wanted to mention was that since we have entered into the MOU with PJM, we have started working with them on finding a way to transition those two functions even earlier than other functions so PJM could be doing it for us in anticipation of the full activity later.

CHAIRMAN WOOD: Let me follow up on that. Is it just coincidental that these are the numbers? Are these the right metrics for us to look at in trying to determine if SPP is administering the system on your behalf, equally as to your affiliates as to other people?

MR. BAKER: I didn't have a chance to review those numbers, but I think that may be a better question to ask SPP than to ask us. We use the system like everyone else does. We put in our requests when we feel the need. Some of them get accepted; some of them get rejected.

I can't answer how it relates to other parties, because I don't sit in there trading.

CHAIRMAN WOOD: We'll follow up on that. Thank you for bringing that point up.

MR. BAKER: Why are we here today? I want to start this off with a little story. A man is traveling from Point A to Point B. He walks through the woods until he finds a horse. He rides it until he reaches the mountains.

Then he trades the horse for a burro to trek across the rocky crags ahead. Eventually, he comes to an ocean. The burro can't swim, so the man swaps the burro for a boat.

An observer says, first you want to walk, then you want a horse, then a burro, and now you're sailing. Why can't you make a decision and stick to it, to which the man replies, I did. I decided to go from Point A to Point B.

Likewise, AEP has not changed its goal. Our destination has always been the same -- robust, vibrant, competitive electric market through RTO formation, a destination shared by the Commission.

We've had to change our mode of transportation a few times, but our goal remains the same. We have reached the last leg of our journey, and the boat will sail with PJM, but whether we join as part of a gridco or as transmission owner, individually, remains to be seen, but we are committed to joining PJM.

There are a number of reasons we've chosen PJM to complete our journey. Although this was not the market design that AEP has historically advocated, the Commission's standard market design is based on the PJM model. Standard of excellence is one of AEP's four stated cultural roots.

PJM has proven to be the standard, and AEP intends to be part of it. PJM is the state-of-the-art market. States with customer choice rely on day-ahead and real-time energy, imbalance, ancillary services, and price discovery, all best achieved through such a market.

In AEP's Eastern Region, Virginia, Ohio, and Michigan all fall into that category, nearby Illinois, as well. MISO hopes to have its market ready to go by 2004.

PJM offers the choice now. We're ready to get on with this; we don't want to wait any longer. Not only is PJM the Commission's standard, it's a proven standard. PJM is not a newcomer to the functions of an RTO.

Affiliating with PJM will prevent further delays, potential false starts, and additional startup costs. A fully-functioning RTO offers no administrative charges, not educated guesses, or ball park figures.

Our affiliation with PJM will provide AEP access to PJM's already-approved congestion management, market mitigation, and market monitoring systems. We will no longer need to worry about public misperceptions regarding AEP's control of TLRs. In fact, the entire TLR question will dissipate for AEP through its association with PJM, because the RTOs have agreed to recognize each other's activities.

In determining ATC, wholesale market activity will reduce the chance of the grid being oversold due to lack of coordination, and with PJM, this is a situation that is immediately correctable, due to PJM's already-operating congestion management functions.

PJM will provide independence with the establishment of PJM-West and the system is now contiguous with AEP's eastern boundaries. This helps us in several ways:

Membership in PJM will shore up AEP's

transmission problem area, the Kanawha Map Funk Congestion Point, which impacts interconnections between Virginia Power, Allegheny, and AEP. Virginia Power announced yesterday that it will affiliate with PJM, meaning that the congestion area will be totally with PJM's system.

Although the construction will eliminate the congestion points, central dispatch will alleviate the symptoms, if not the cause. The highway system, as we see it, for transmission, starts in central Illinois and flows east.

One of the concerns in the Alliance was its toll booth effect on traffic between the midwest and the east. Until we actually do achieve a national market, a tool booth will exist, regardless of which RTO is playing the role.

If AEP were to affiliate with MISO, that toll booth would be at the eastern end of the AEP system, effectively placing some level of economic impact between western generation and the high-cost northeastern states, potentially creating some sort of price pocket.

As the Alliance companies join PJM, that toll booth lands further to the west, to western lower-cost generators that will alleviate the price pocket in the northeast. This provides a vehicle to reach the Commission's destination of a standardize national market devoid of price pockets.

The reserve margin requirements for PJM-West now are more compatible with ECAR approaches. This was not always the case with PJM.

A few detractors have raised issues, as they will, but we think that a number of the concerns that others have stated, are either unfounded or moot points. The seams issue has been raised.

AEP Is a big company; it doesn't matter whether we join PJM or MISO, there will be seams. But with the proposed PJM/MISO/SPP common market, the seams questions for these markets become transitional issues.

The interconnection has been raised. AEP is as interconnected as you are going to find. We are closely tied to all of our neighbors with pretty large interconnections.

This is not a situation that will change if we join PJM. Historical trading patterns, everyone wants to access natural markets, based on historical trading patterns.

In a pancake world, the rule of thumb was that two wheel deals didn't generally take place. The core of our trading activities was through direct interconnections. Allegheny was not part of PJM in the past, therefore, historical trading patterns wouldn't have included as much

PJM transactions as they do today.

At that point, there were pancakes. In the last two days, AEP sold 1800 megawatts into PJM. We think this is a good thing. We're working through details with PJM, and doing so as rapidly as possible.

Since announcing our MOU in May, we've met numerous times. We're discussing scheduling, costs, pricing, revenue distribution, neutrality, and those talks, frankly, have gone better with PJM than they ever did with MISO.

We formed project implementation teams to help meet our goal of transferring control of AEP's transmission grid to PJM by December, 2002, and beginning energy market participation by May of 2003.

Just yesterday, I'm pleased to state, AEP, Commonwealth Edison, and Illinois Power, signed an MOU with PJM and National Grid to participate in PJM jointly under an ITC.

The MOU allows a 30-day, dual-track development period with the hope of speeding up the transition time for these companies to integrate into PJM and to provide the opportunity to develop the business plan for an ITC. Things are progressing at a rapid pace.

AEP and PJM are a good combination; they complement each other, and AEP remains committed to becoming a thriving member of the PJM market, and to do so as fast as prudently possible, because, just like the Commission, we still want to get from Point A to Point B as expeditiously as possible.

And now we've found our ride and the opposite shore is just within reach.

CHAIRMAN WOOD: Very literary. We're at the boat, not the burro, though, right?

(Laughter.)

CHAIRMAN WOOD: Walk me through this, because I didn't see the announcement. I understand we had a filing, as well, yesterday about the nature of the announcement of your company and others with PJM to develop an ITC company within PJM-West. Does that look pretty much like the ITC that we did in our Alliance Order?

MR. BAKER: There are two periods. The MOU I mentioned has a dual track. The first is to attempt to use the systems that have been developed for the Alliance Companies under what we've termed BridgeCo, and being able to use those systems in the east to facilitate the transition, and to potentially reduce the cost of implementation into PJM.

At the same time, we will work on the business plan for an ITC. There is a layout of the delegation of functions. They are in two parts: The first part is a day-one part, before we are fully integrated into the market, which is very consistent, I believe, with what you had ordered.

Then there is a second period, which is, once we're fully integrated, which is more in keeping with what PJM believes the design needs to be in their market.

CHAIRMAN WOOD: Meaning what? Does that look like the day-two part of the Alliance order we did, or the TransLink order?

MR. BAKER: It's more functions moves to PJM than I believe was indicated in a TransLink order.

CHAIRMAN WOOD: If that is the case as with the original Alliance, you want to divest your TransLink assets. To whom would you divest?

MR. BAKER: I'm sorry. I thought we were talking about delegation of functions. But the divestiture, if we can create the business model, we expect that it would look just like -- in that area, would look like what we had done in the original to provide the opportunity for divestiture.

CHAIRMAN WOOD: Nora?

COMMISSIONER BROWNELL: I'm a little confused. So the Part II of the process of operating under PJM would be different from the vision that we outlined in terms of the slice-and-dice of functions, because PJM has a different view of the market than we do.

MR. BAKER: PJM has indicated that they believe that their model requires that the transmission owner -- that even an independent transmission owner has to delegate functions to the RTO, and they can probably answer this better than I can. But I'll tell you my understanding, because they consider a transmission owner to be a market participant; therefore, there has to be a different delegation of functions, in their mind.

COMMISSIONER BROWNELL: I'll look forward to hearing from the other market participants who have signed up for the PJM vision and PJM themselves, but I have to say that what I heard PJM say to me and others was that the original orders we did in terms of dividing up functions worked.

I think, Nick, we've heard you say that, so I want to be real careful that we don't have 18 different visions out there. It's kind of inconsistent with our standardization.

CHAIRMAN WOOD: I was going to say, personally, I have journeyed on foot, horse, and burro, and on the whole, Transco concept, and I've gotten pretty comfortable, as I think when I was out at MARC yesterday. A lot of parties in the midwest are with having Transco-type organizations underneath an energy market umbrella, administered, in that case, by MISO.

I think the business prospects for that model, for which I give those here at the table a lot of credit for really introducing that to the national debate. The business prospects for that model certainly are very investable, and sellable on Wall Street, as well as with the general public, as well as with those of us who like structural remedies, rather than behavioral.

I just want to make sure that we aren't settling for less than the vision you articulated when you first started talking about a Trasco-type model. But we have more people to talk to, so let's do that first.

MR. SZWED: Good afternoon. I'm Stan Szwed, Vice President of Transmission for First Energy Corp. In that capacity, I am the executive in charge of our transmission business unit.

What I need to say is that we consist of a couple of parts: The one part is called American Transmission Systems, Incorporated. That is a wholly-owned subsidiary of First Energy. It houses our transmission assets, primarily in Ohio, and some in Western Pennsylvania.

(Slide.)

MR. SZWED: And we also own transmission through the acquisition of GPU, a merger that we concluded with them last year. We have transmission assets that are housed in operating companies -- Jersey Central Power and Light, Metropolitan Edison, and Pennsylvania Electric. Those companies and the transmission assets there are part of PJM, and we're committed to leave those assets in PJM.

What I really want to talk about today, is, when we refer to First Energy, is our transmission assets in Ohio and Western Pennsylvania.

(Slide.)

MR. SZWED: As we stated to you in our May 28th filing, we will join the Midwest ISO, either as part of an independent transmission company or as an individual transmission owner. I'm very pleased to say that our first preference, being part of an independent transmission company, came to terms last week, as we, along with National Grid, Ameren, and NIPSCO, announced the formation of Grid America, an independent transmission company that would come under the umbrella of the Midwest ISO under the arrangements of Appendix I, and directives you provided in your April 25th order.

I want to say that that has been important to us, that the whole notion of creating a viable, independent transmission business that has the ability to serve customers and seek investment has been a fundamental proposition of my company for the last five years, since First Energy was formed back in 1997.

We have advocated that in every forum we can possibly imagine, and really propelled that through the

Alliance development process with the Transco development in the Alliance. And we feel that our goal in that regard is very similar to the goal that this Commission would like to see happen in terms of Order 2000, as well as restructuring of the transmission business.

We believe that forming the ITC under the MISO with our Grid America proposition, which you will hear about, is something that will work, and is something that we feel is consistent with our objective, as well as yours.

I'd like to get specific now with the questions that you've asked about why the Midwest ISO? I have a chart that maybe you have in front of you, that is on the screen now, too. First of all, we really felt that the order of April 25th really provided a clear path to the Midwest ISO, and perhaps more importantly, that opportunity to set up the ITC under the Midwest ISO.

We wanted to take advantage of that opportunity. We believe that after consideration of the functional separation, the functions between what an RTO would do and what the ITC would do, was enough to demonstrate the business proposition of the ITC, and we were further influenced by the fact that National Grid was continuing, and wanting to be willing to proceed within the framework of that April 25th order.

We also felt that a very important ingredient in creating effective transmission companies for the future was rate design. In that April 25th order, you had endorsed an Alliance proposition for rate design for a transition period that included lost revenue recovery, and, furthermore, had delineation of functions, and gave authority to the independent transmission company to establish rate design and revenue requirements, of course, under the overview of the RTO.

We feel that it's just so important to attracting investment and maintaining the transmission grid. Lastly, that order and with the Grid America option, we are able to use the facilities, hardware, software, and people that had previously been developed for the Alliance. I can't say enough about the discussions we had with the MISO, the successful discussions we had with the MISO about looking toward the integration of that, as well as the support of a couple of members of your staff, Dan Larcamp and Chris Miller, with regard to bringing that arrangement to fruition.

We also, at First Energy, wanted to preserve the independent transmission company option. As I said before, the ITC has been our goal, and being in a MISO, we believe, provides that best opportunity, and a Grid America transaction, I think we can bring that opportunity to fruition.

We believe Appendix I can accommodate the two fundamental functions of an ITC, the ability to serve customers and the ability to attract investment. We also feel the Appendix I possibility also can effectively incorporate the separation of functions that you have delineated in the April 25th Order. But we also have a clear path to a commercial transaction. The arrangements we have under the Grid America deal provide for divestiture of transmission assets, either for cash, passive investment, and ultimately the possibility of an IPO.

National Grid, and I'm sure they'll say this too, is also willing to invest some $500 million in capital improvements, infrastructure and acquisition for transmission in this part of the country. Another important factor of First Energy is stabilizing RTO participation. MISO is an approved RTO, there's no question about that. We believe it's time to get on with things, and we feel that from our company's standpoint, it's time to be part of the RTO absolutely. It's important to our customers, our employees, our shareowners, our regulators, to bring us stability and certainty to what has been a changing landscape over the last few years.

I can tell you, being responsible for operations of transmission at First Energy and having responsibility for people who sit in the control room every day, day after day, keeping the lights on and trying to tell them what we're going to do when we're going to do it, who's going to be their boss, what functions they're going to take. That's not a good thing to do. So from our standpoint, we need to get this stable. We need to have their roles identified and what that means in terms of RTO and ITC.

Lastly, with First Energy coming into the Midwest ISO, it adds a great deal of load and generation into the footprint, some 14,000 megawatts of load. When you consider Ameren and NIPSCO coming into the footprint some 28,000 megawatts of load are added. We believe this provides a greater opportunity for competition in what we believe to be our natural market.

In conclusion, we've had over the last few years a great deal of discussion, dialogue, regulatory filings, debate in moving toward trying to get to an RTO. We believe it's time to move on; maybe less talk, more implementation, more action, getting things done. We are, I want you to know, at First Energy are committed to moving forward. Our decision to join MISO as part of Great America or as an individual owner, provides for us moving toward operation in an RTO this year, and we believe consistent with implementing the policy that you seek.

Thank you.

CHAIRMAN WOOD: Thank you. What kind of

reliability issues do you have with the PJM companies to either side of you? What kind of reliability issues would arise because of that configuration?

MR. SZWED: Between our two systems?

CHAIRMAN WOOD: Between First Energy's ATSI system and its neighboring systems.

MR. SZWED: I don't know of any specific reliability issues that we have. We are able to transact in certain conditions at certain times and I don't know of any specific reliability issue that we have in that particular arena.

CHAIRMAN WOOD: You're surrounded in some part by AEP systems in Ohio, and then of course PJM is generally to the east of you. What type of issues with loop flows, coordination, and all of that?

MR. SZWED: We do experience issues with loop flow on certain types of transactions. We are connected to eastern companies, to PJM directly, we're also connected to Allegheny, Duquesne, strong interties into Michigan, very strong interties into Michigan, as well as into Dayton and AEP. We are right now part of a security coordination process that is administered through ECAR which considers a number of ECAR companies and have been part of that ECAR process since that was started.

I believe it has worked. Under this new

configuration based on the elections we have, there's always going to be some seams. As long as you have multiple RTOs, there are going to be seams. I don't know what the perfect configuration of the RTO should be. Certain configurations may be less optimal than others but I think they can work. Certain configurations may just require greater coordination, more delineation and administration of seams agreements and that type of thing. But I think they can work, and I think that could be helpful so by standard market design as we move toward getting those in place. So we aren't necessarily as concerned with regard to those types of things given the situation we've been working under for the last several years as well as the move towards standard market design that we're about to get to.

CHAIRMAN WOOD: I assume First Energy makes off-system sales at wholesale?

MR. SZWED: Yes, we do, although I must say we look at our total load picture for all of First Energy. We have about 22,000 megawatts of load. We have about 14,000 megawatts of generation, and the 14,000 megawatts of generation will also be reduced by about 2500 when we complete a transaction or sale of power plants to NRG. So most of our capacity and our generation is directed to providing service to our retail customers, be they our unregulated customers or under various obligations we have in the various states we operate in.

CHAIRMAN WOOD: Mr. Baker, what's the case for AEP off-system sales volumes?

MR. BAKER: We make significant off-system sales. Our reserves are diminishing. Locationally, we generally sell power into the north and the east and the southeast have historically been our major markets that we've sold off-system.

CHAIRMAN WOOD: With the agreement that AEP has reached with PJM, from an AEP interconnecting generator selling to anyplace else in the AEP, that would just be subject to the one transmission access fee in addition of course to losses and congestion from MMP, but is there a second regional rate?

MR. BAKER: If we would sell into PJM, there would not be an additional access fee. If we were to sell into MISO, we would have to pay an out rate from PJM or if we were to go south, we would have to pay an out rate to get out of PJM.

CHAIRMAN WOOD: And that rate goes to the PJM transmission owners, right?

MR. BAKER: It would go into the pot of dollars that get distributed.

CHAIRMAN WOOD: I guess with Dominion's election, it would be not to them but to the TVA?

MR. BAKER: To CPNL. Historically, people have generally traded, as I mentioned with a neighbor. You paid one fee to get out of your area. Generally, the other person had a sunk cost in his network rate so it was one incremental fee. So with this configuration, the worst case anyone has is that same one fee that you had with your direct interconnects from the southern parts of MISO all the way up into PJM.

CHAIRMAN WOOD: What is the out rate for PJM? Are you all negotiating that for PJM West for you to send power back to Indiana?

MR. BAKER: That will be part of the discussion when we figure out if it's in there now. If we know that, we can start to finalize what that number would be.

MR. LAUGHLIN: Pat, I'm PJM, since I happen to be here, if I can jump in. Putting it back together, the out rate right now is 67 cents for non-firm, and that's non-firm through PJM or out of PJM. Typically non-firm is the service used if it's sold into areas where TLRs are prevalent, and occasionally people like to buy firm service just to get a higher priority in TLRs. But as we go to the joint and common market and get to the single large market and internalize all of that, there won't be any real need to use a firm service.

CHAIRMAN WOOD: That's helpful, thank you. And a comparable number, Jim, in MISO now. Is the tariff right at two bucks?

MR. TORGERSON: The through and out rate is like $6.40 a megawatt hour but we've discounted it on a firm basis. It's currently been discounted to $3.00 on firm and $2.00 on non-firm.

CHAIRMAN WOOD: Thank you. Ms. Flanagan?

MS. FLANAGAN: Good afternoon. I appreciate the opportunity to speak to you today. Dayton Power & Light is an integrated, investor-owned utility located in West Central Ohio. We have a peak load of 3130 megawatts, 4500 megawatts of generating capability, 2300 miles of transmission lines and transmission interconnections with AEP, Cinegy and First Energy. DP&L is highly interconnected with AEP at the 345, 138, and 69 kV levels which translates to a total of 6300 MVA of transmission interconnection capability, over twice DP&L's peak load.

DP&L decided to join PJM because it is an already established market, well functioning transmission organization with a fully functioning market. From the Commission's orders, SMD papers and various speeches, it appears that PJM is getting the standard market design stakeholder process and independence concepts right. Having just been through the failed Alliance experience, DP&L

elected to join PJM because of their proven track record and foresight as to the direction the industry is moving.

With the announcement of AEP joining PJM, DP&L found that it had two options. Either join PJM or join MISO. We recognize that our RTO selection would have to make sense as part of a continuous RTO. In this respect, not only is DP&L highly interconnected with AEP, but our service area is directly contiguous with that of AEP, just west of AEP's Columbus southern power subsidiary. Therefore, in terms of both electrical topography and physical geography, DP&L's service area is a logical extension of PJM or PJM West.

While we understand the Commission's immediate concerns about seams issues between PJM and MISO, we believe the Commission's work towards developing a standard market design, combined with inter-RTO coordination and cooperation initiatives will address those concerns over the next few years. We believe these mechanisms, which are already underway, will result in viable working RTOs while allowing the Commission to remain true to the voluntary spirit of Order 2000. Thank you.

(Pause.)

CHAIRMAN WOOD: Questions?

(No response.)

CHAIRMAN WOOD: Thank you. Yes, sir?

MR. MULCHAY: Good afternoon. I represent

Northern Indiana Public Service Company. I am responsible for the transmission operation at NIPSCO. We would like to thank the Commission for the opportunity to participate today. In the course of this decision process, we have been encouraged by the Federal Energy Regulatory Commission ruling in April of 2002, which spoke highly of the RTO model in which an ITC operates under a not-for-profit RTO.

(Slide.)

NIPSCO believes that the independent transmission company model provides appropriate incentives to promote efficiency and stimulate infrastructure investments, investments that would improve the access to and the flexibility of the interconnected system. Also, the MISO structure expressly provides for the operation of an ITC within the RTO and in fact has several ITCs currently operating within its structure. Additionally, Grid America, the ITC we have aligned with, has attracted a highly qualified experienced and independent transmission manager in National Grid. Grid America we believe will greatly contribute to the timely development of an open and unencumbered transmission system.

In fact, our previous work with the Alliance provides a platform for rapid integration of the ITC into the MISO systems. The Commission's April 25th, 2002 Order also gave us comfort relative to recovery and appropriate rate design which we believe can be implemented through the ITC without negatively impacting MISO's schedule ten rate adder. Our decision results from a careful thoughtful process that began with our early involvement in the development of the MISO, and subsequent active involvement with the Alliance organization.

(Slide.)

We continue to believe operational efficiency and accessibility are important in meeting our obligations to our customers in their current structure since we are a net purchaser of generation at the peak. We further believe that a fully functional transmission system will likely be even more important to participants in the common market structure that FERC is working to create. The NIPSCO system is not large in relative terms but it has a substantial industrial demand that over time has dictated that we develop a very robust transmission system which consists of 345 and 138 kV. Due to our geographic location, we become an important link between the ECAR and the main reliability regions such that over time our system has evolved into a natural interchange that routinely and reliably meets the needs of our customers and the other participants within the region.

For example, the NIPSCO system connects the

Michigan systems directly to the MISO network. We also took into account the fact that the Indiana Utility Regulatory Commission has often expressed a preference for our membership in the MISO organization. For all these reasons, NIPSCO believes in and supports the Grid America model. That is why we made the commitment to join Grid America and to become part of the MISO RTO system. We believe that the Grid America model operating within MISO will support the continued provision of high quality reliable service, both today and tomorrow, and we continue to believe that it's just simply good business to pay attention to customer service and reliability.

Thank you again for the opportunity.

CHAIRMAN WOOD: What will be the reliability issues relating to kind of the interconnectivity or the interweaving of what would be PJM's footprint with the MISO footprint with you on the MISO side up where you are?

MR. MULCHAY: We're not connected to PJM. We are connected to AEP today.

CHAIRMAN WOOD: Right. I'm assuming everything stays as everybody elected. NIPSCO will be kind of between worlds and I guess physically underneath a few transmission lines that go over it and go to the other side. What reliability issues come forth with that that we need to be apprised of?

MR. MULCHAY: I think what you described is a seam and whatever issues are in that particular seam will be there, whether they address pricing issues or congestion issues.

CHAIRMAN WOOD: Is that seam any worse electrically? Is that seam any worse with a jagged line like the one we've got now versus some straighter line that may look like -- these lines are all arbitrarily drawn?

MR. MULCHAY: I think a seam is rightly defined as a number of interconnection points. Each interconnection point may have a different response depending on the hardware located at that point, whether that might be wire size or transformer interconnect or interconnect size, whatever that might be. I think also when you operate in these RTO configurations, we may well see some different flow patterns that will bring back or bring on some totally different issues from what we experienced today. Our experience today has not been overwhelming. We are subjected, from time to time, to some TLRs. I really can't answer specifically as to what form those issues might take in the future because I believe that once these RTOs are formed, there will be some adjustment and some change to the flow patterns that we currently experience today.

CHAIRMAN WOOD: Thank you. Welcome home.

MS. MOLER: Thank you, Mr. Chairman and

Commissioners. My name is Elizabeth Moler known as Betsy to my friends. I serve as senior vice president of Exelon Corporation. With me today are Celia David and Steve Nallon, both of whom are vice presidents of Commonwealth Edison, and Karen Hill who will join Exelon on Monday, July 1st.

Commonwealth Edison is headquartered in Chicago as is Exelon. It is our largest distribution subsidiary. PECo Energy in PJM is located in Philadelphia, and is the other. My goal today is to briefly explain ComEd's choice to join PJM for its RTO. The PJM decision was a surprise to some. Once you see the analysis, I hope you will understand the decision is solidly grounded on natural market characteristics. The decision to join PJM was based on a number of factors. First and foremost the ability to assure continued reliability of the ComEd transmission system. Second, PJM with AEP is ComEd's natural market and I will elaborate further. Third, the PJM market structure already supports retail access which we have today in Illinois for all customers.

From a reliability point of view, there are two critical facts to weigh. First the strength of our physical interties, and second, where we import power from when there's a shortage of generation in the control area.

Let's look at each.

(Slide.)

MS. MOLER: When we look at the electric interconnections as they impact RTO choice, it is important to recall Phil Harris' statement two weeks ago, that the electric topology is important, not state boundaries or geography, because the electrical characteristics of the transmission system dictate how electricity flows, not state borders.

As this slide number 3 in my deck shows, Com Ed's ties to AEP and IP, both of which will be in PJM, are strong. Com Ed has one 765 kV and two 345 kV ties to AEP. The summer normal capacity of these ties exceeds 5,900 megawatts. Com Ed has two 345 kV and six 138 kV ties to IP. The normal capacity of these ties exceeds 2,900 megawatt. The ratings of these interconnections are higher in the winter and under emergency conditions.

In order to ensure reliable operation of Com Ed's transmission system, we must be in an RTO that encompasses these two vitally important interties. It's that simple.

(Slide.)

MS. MOLER: The Commission has recently coined the term "natural markets" and is saying that an RTO must encompass its utility member's natural markets. We've tried to interpret what that means. We believe that any interpretation of what constitutes a natural market really must look at where actual transactions take place, real flows, real transactions.

This slide is one example of those kinds of transactions that we believe you have to look at. It shows the source of imports into the Com Ed control area in 2001. Two-thirds were from AEP and IP. By any reasonable interpretation, AEP and IP are Com Ed's principal natural markets.

(Slide.)

MS. MOLER: The next slide graphically illustrates that neither geography nor state boundaries reveals true natural markets, given Com Ed's import patterns. AEP and IP are our principal sources of imports.

Let's turn now to the next slide, where we show where we import power from when there is a shortage of generation in the control area.

(Slide.)

MS. MOLER: This too is a function of the physical interconnections as well as where energy is available. In other words, surplus generating capacity.

May 19, 1998 is an infamous day in Com Ed history. It was a day when we had four nuclear units down, several units out for maintenance, and a very early heat wave. We don't want to repeat that day. However, when the Com Ed control area needed in excess of 5,200 megawatts of emergency power, 77 percent of the energy came from or through the AEP and IP transmission systems with 66 percent of that energy to or through AEP.

From a reliability point of view, the Com Ed control area needs to be in the same RTO as these facilities, particularly given the fact that the RTO will dispatch the market whether it is an easy day or a really tough day like May 19th, 1998 was. There simply is not the interconnection capacity or the energy available in the MISO systems to support this kind of emergency to keep the lights on in Chicago. And as the mayor of Chicago will tell you, that's a very desirable thing. We've tried it both ways.

(Laughter.)

MS. MOLER: The next slide graphically illustrates that neither geography nor state boundary really reveals the natural markets, given Com Ed's emergency import patterns.

(Slide.)

MS. MOLER: The data on the previous slide are depicted in this slide. Next slide.

(Slide.)

MS. MOLER: Clearly, generation export patterns are an important component of a utility's natural market. This slide provides an indication of the natural market for generation, and I will say it is all generation interconnected to the Com Ed transmission system. Com Ed does not own generation. The generation capacity owned by Com Ed prior to our merger with PeCo Energy was transferred to Exelon generation. Also, significantly, we have sold a lot of our generation to Edison's midwest generation subsidiary.

In addition, thousands of megawatts of Merchant generation have connected to the Com Ed system. Some have alleged that our decision to go to PJM was principally due to our desire to benefit our affiliated generation. This slide clearly depicts that that is not the case. This decision benefits all generation interconnected to Com Ed. Over 60 percent of the megawatt hours delivered for generation connected to the Com Ed transmission system to deliver points outside the Com Ed service area in 2001 went into or through AEP.

Not only is this a substantial majority of the actual transactions, but the sheer volume of these transactions exceeded 17.7 million megawatt hours. That in and of itself is larger than most of the systems in the

United States. To put that in perspective, the total energy served by Central Illinois Light Company in 2001 is over 9 million megawatt hours. We export a lot.

Some have alleged, as I reported earlier, that Com Ed's desire to go to PJM was driven by a desire to favor our affiliate. This is simply not the case. It helps all generators connected to Com Ed.

(Slide.)

MS. MOLER: The next slide graphically illustrates again that neither geography nor state boundaries reveals true natural markets for generation exported from Com Ed's service territory. You can't look at a map and figure this out. You have to look at natural markets and actual transactions.

(Slide.)

MS. MOLER: Finally, I would like to note the very important similarities between Illinois and the PJM states. The most important is retail access. All of Com Ed's customers have the ability to choose competitive suppliers, and over 20,000 customers accounting for approximately 5,600 megawatts of load over 21 million megawatt hours have already chosen retail access. These are principally the large commercial and industrial customers. This makes Illinois, and especially Com Ed's customers different from those states which do not have retail access.

Com Ed and its customers need access to the kinds of markets that PJM operates, and they need that access as soon as possible, which is what PJM will provide. PJM is experienced in extending its markets into PJM West, and this track record is something Com Ed and our customers can count on. While there will be a single common market between PJM and MISO by the end of 2005, getting the market to Illinois customers as soon as possible, which PJM will do, will provide tangible customer benefits and becomes paramount to us, given our open access regime.

(Slide.)

MS. MOLER: Our final slide. In summary, by any measure -- strength of the transmission system, ability to import energy during an emergency, benefits to customers, and the natural markets for generation connected to the Com Ed transmission system -- Com Ed should be in PJM.

Mr. Chairman, you have characterized yourself as agnostic about which RTO each company should join. You've also bemoaned delays in RTO formation. I can assure you we share your frustration. We are ready to join PJM. We are committed to join PJM. Our MOU filed yesterday makes that very clear. Please give us the tools to go ahead so we can be in operation under PJM this year.

Thank you.

CHAIRMAN WOOD: Thank you. To piggyback on the same question I asked Mr. Baker, what is your understanding of where kind of structurally you go within PJM West, both with the national grid set -- there's Nick over there -- the national grid setup, and I think the question Nora was following up on that kind of got my interest level raised to the day two issues there.

You are very articulate and continue to be a very articulate spokesperson for that vision of a business-oriented transmission company, and I want to understand how that has not been extinguished by what I just heard may be the path for the Alliance companies that have chosen to go to PJM.

MS. MOLER: I think you have to think not in terms of day one, day two and day three. And let me define day one, day two and day three. Day one, which we hope will be this fall, will have the maximum amount of functionality for the gridco if we form a gridco. And that is a functionality that clearly mirrors the TransLink order.

Day two will have the full integration of the companies, the four companies into PJM under the PJM energy market. If we have an ITC, which Com Ed strongly supports in our internal discussions. We are an ardent ITC advocate and very firm supporters of having national grid, assuming we can reach an acceptable business arrangement, I believe we can and we'll do so shortly. But day two has the full integration of our companies into the PJM market.

National grid will be there in that context but I think at that point, they will have more limited functionality than they would have on day one because of the operation of the PJM market. However, they are also the investment vehicle, potential purchaser for our transmission assets, and hopefully an active player in the area in providing new construction and interconnection and upgrades of the grid. They will still be a player.

Day three is standard market design. It's not clear to us yet when day three will actually be, depending on when the Commission issues a standard market design final rule and what the effective date of that final rule will be and whether it will be any different than PJM currently is.

We advocate a stronger role for transmission owners under standard market design. We're very strongly supportive of SMD as a company. But we think you need to beef up some of the functionality for the transmission owner, in this case it would be presumably national grid as well in that context.

CHAIRMAN WOOD: The day two where we indicated on the TransLink order and I think by reference in the Alliance order from a couple of months ago, day two certainly did indicate some retreat from the day one duties that were allocated to the ITC.

There was some pullback to the umbrella company, in that case, MISO. How different is that day two of the TransLink order? And admittedly, it was a bit amorphus, but at least we indicated the areas where the pullback comes from and what it would be under the day two you;re talking about here.

MS. MOLER: In the memorandum of understanding we filed yesterday, we delineate in two attachments the day one functionality and the day two functionality. The day two functionality is under PJM because of PJM's market operation. It's substantially different than it was contemplated in the TransLink and Alliance orders. That's again because of the PJM market.

CHAIRMAN WOOD: And you're thinking to really have an attractive investment vehicle long term for an ITC business, that that has to come back kind of between day one and day two that you're envisioning here perhaps?

MS. MOLER: I think it has to recognize the role of the system operator as well as the market function. I think frankly it was a little heavy on the market functions and not as affirming as we would like to see of the transmission owner. The upgrades, the investment, the knitting together of the systems and the like.

CHAIRMAN WOOD: That is a continuing story. But thank you for flagging where that is. Had Com Ed been in

MISO, would the current export fee from MISO to PJM, for example, as you indicate that's where a lot of the traffic goes, would that have been a pretty big cost? You're right. It's not just your generation but a lot of other people's generation too.

If I were to look at that 28 million megawatt hours and multiply that by the six bucks or the three bucks or whatever it's discounted to, is that kind of the tollgate fee that we're talking about of being a member of MISO?

MS. MOLER: That is part of the consideration. The reliability considerations and the interties, and frankly the planning considerations, which I didn't get into because of my five-minute limitation, you can't plan the Com Ed system without looking at AEP. It's just the reality of the interties.

It's also important to remember that the situation will net be better off than we are today because we don't have the multiple toll gates. We will just have two seams. You will also only have two system operators, and when you ask questions about reliability, you'll have PJM and MISO interfacing and not all the companies at this table.

CHAIRMAN WOOD: What's your thought about how the PJM MISO SPP integration concept overlays what you and your colleagues here at the table have decided to do? Does that matter at all? Does that factor in pro or con? What is the import of that?

MS. MOLER: We have made a filing that was in support of the memorandum of agreement, I think that was the term. It wasn't an MOU, it was an MOA, between MISO and PJM. Frankly, we're worried about the fact that some of the deadlines that have come and gone have been missed. We are very confident of PJM's ability to do this because, you know, Exelon after all is the parent of PECo. We operate there every day. We're confident of the PJM market integration capabilities, less so with MISO. And it's principally missed deadlines.

CHAIRMAN WOOD: But as a concept, assuming operational issues gets worked out, is that something that this Commission ought to put much faith in as far as being the real solution to the seam issue more broadly, or is that just kind of --

MS. MOLER: I look at that MOA as a who does it, not what they do. And what they do will be implement standard market design. I think that is where you are correctly putting your major efforts. Once that gets decided and implemented, we'll all be better off. We are enthusiastic about that, and I really wouldn't worry so much about who is doing it, whether it's PJM helping MISO, whether it's the Cal ISO doing functions in the West.

I think there's a question about the talent pool, frankly, and how many smart people are there who really are good at this. And PJM has lots of them, but I don't think they can handle the whole country.

COMMISSIONER BROWNELL: Don't tell Phil.

(Laughter.)

MS. MOLER: Phil singlehandedly could, but his troops would be tired. But I don't really worry so much about who does it. I do for us, but I do in terms of whether PJM helps MISO achieve that goal. That's great. We're for it. Because I think they know how to do it.

CHAIRMAN WOOD: The rate issue. Leave it alone? Do something about it? Assume you guys have picked up your dance partner and we don't come bust the chaperon for letting that happen.

MS. MOLER: I hope you'll let us dance.

CHAIRMAN WOOD: We'll let you know real quick. Should anything be done about the import-export fees?

MS. MOLER: I personally would not spend all my time on a 206 order right now. Instead, I would see what happens in the marketplace once it gets started.

CHAIRMAN WOOD: I'd like to hear the other folks' views on that actually, the ones I've already passed by.

MR. SZWED: Just a quick comment on that. I think we recognize that in the decision to go to the MISO and in developing the documents with Grid America and what Jim said before about recognizing the neat discount to have transactions to go forward is a provision in our term arrangements for MISO to continue to either provide that discounting capability to encourage throughput or to even set a rate, if that were the more appropriate thing to do.

So I think, Jim, we've tried to address that particular issue in the documents we submitted.

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CHAIRMAN WOOD: And the rest before Betsy. Ms. Flanagan, any thoughts about the rate issue or the seam issue that should be resolved or not resolved?

MS. FLANAGAN: I think it will eventually be resolved, but we also believe that any further delay in this process, from a small company's perspective here, it's very expensive, and the delays have been expensive. Getting the markets moving and getting us integrated into PJM is probably first and foremost. The markets will ultimately resolve the rate issues.

CHAIRMAN WOOD: Let me ask you and Betsy this both. What time frame would operational control be transferred to the PJM. Craig had said by the end of this calendar year. Would that be a little bit different for the other?

MS. FLANAGAN: Dayton would really be subject to the information of AEP.

MS. MOLER: One of the questions that is unspoken yet on today's panel is how we get to yes, and having had numerous orders, approving the Alliance RTO, and then suddenly oops, well. We had to change our plans and now having filed our petitions for a declaratory order and then having been given an invitation to choose where we want to go, we are now facing additional investment to actually get up and running by this fall.

Some companies you will hear are saying no more until we're sure, no more money. We really need some certainty in this process. That's a very serious issue with us. If you told us this afternoon at the end of this session took a straw poll, got Bill on the phone and told us go for it, we'd be delighted; we'd go. But we really need some certainty and we'd spend the money that we need to get operational by this fall.

But right now having collectively spent over $90 million, that's just the lawyers and systems, that doesn't include our internal costs, our own make-ready costs, we're a little gun shy.

CHAIRMAN WOOD: We just want to know what's on our end of the deal too. Do we need to do rate issues? Are there going to be issues from the other people who aren't at the table that have other seams issues that you all in your desire to justify your own decisions admittedly aren't real eager to point out? I mean that's at this point rates, money, you can resolve that. Off the top of my head, I would rather you folks be happier with whomever you chose to dance with than a shotgun marriage. Don't get me wrong on that but we do have an obligation to look at. Is this thing really a reliable market. I'm getting an earful from my colleagues in the Midwestern Commissions yesterday coming from different angles. The concern about are we just missing an opportunity here to go get the best and most efficient market out in the entire Midwest. I don't want to just gloss over those concerns. Ms. Patton?

MS. PATTON: Thank you. I'm Cathy Patton, Senior Vice President and General Counsel for the Illinois Power Company. I welcome this opportunity to present Illinois Power's reasons to join PJM as part of a dialogue rather than just through pleadings.

(Slide.)

Simply put, IP joined PJM because Commonwealth Edison and AEP decided to join PJM. Their assessment and choices naturally impact IP's choice. IP considered operational capabilities, natural markets and many qualitative factors in making our choice. As this diagram shows here, Illinois Power has 345 kV interconnections with four utilities; Ameren, AEP, ComEd, and TVA.

In analyzing what RTO to join, we had to look at which RTOs these four utilities were joining. We had to look at the strength of the interconnections and ATC availability, not just the rated capacity. This schematic here shows rated capacity, and while IP's interconnections with Ameren are large from a rated capacity perspective, there's typically little capacity available as it is already under contract to companies typically moving power to markets such as TVA and Entergy. Taking these factors into account, joining the same RTO as ComEd and AEP made the most sense. Thus, one check in the PJM column.

(Slide.)

Next we looked at markets or imports where our native load came from. Here, 50 percent of imports for IP's native load came from ComEd and AEP. Only ten percent came from Ameren. As ComEd and AEP are joining PJM, another check goes to PJM.

Next we looked at what markets power went to when it was exported from our system. In that case, 60 percent of the exports went to ComEd and AEP. Only 19 percent went to Ameren. We then looked at what control area ultimately consumed the power.

(Slide.)

This is where it got interesting. Nineteen percent of the power exported by generators connected to the IP system served load in PJM, 14 percent served load in ComEd, and 11 percent served load in AEP. Another 19 percent went to TVA. Thus 44 percent of the generation IP served load in utilities proposing to join or are already a member of PJM, another 30 percent went to loads not part of MISO. Only 3 percent served load in Ameren. Another check for PJM. Thus from an operational and market perspective, PJM should be our choice hands down.

We next looked at the value to our customers.

Here PJM came out best hands down again. PJM offers a liquid and competitive market with access to diverse supply for market areas that have historically served IP's load. The transparency and robustness of the PJM market would also better promote and support Illinois' retail choice program and encourage new generation. Finally, joining PJM would allow IP to be part of an RTO with full LMP market implementation much sooner.

We next looked at the benefits to IP. Here again PJM had more to offer. PJM's rate design for PJM West doesn't result in cost shifts; it provides a greater opportunity to recover our transmission revenues. What attracted us most to PJM however was that several years experience as an operator and its ability to get us up and running fairly quick. While PJM has had its share of problems, PJM, to its credit, has successfully worked through start-up problems and operates fairly smoothly today.

(Slide.)

We next look at what not MISO. Here our decision to join PJM was sealed. First, joining MISO with ComEd and AEP as part of PJM would basically strand IP from available import markets. Our only strong interconnection with MISO would be Ameren and Ameren has no ATC available either into or out of IP for the summer, and we don't expect that to change. This will limit IP's ability to import supply, at least without the seller having to pay export fees from another RTO. It would also strand generation in IP by having to pay the exorbitant MISO export fee which also serves to discourage new generation. While MISO could get us up and running from a day one transmission perspective on a time line similar to PJM, MISO would not have us up and running under LMP or FERC standard market design until 2004 or 2005.

However, all this aside, what convinced us most that MISO is not the RTO for us to join was MISO's track record. Here I talked with people who have actual day-to-day experience in dealing with MISO. The Dynegy traders were quick to send me several pages of complaints. To highlight a few, MISO's ATCs are not accurate. Their OASIS was frequently down, and they are slow to respond to customer requests and inquiries. By our count, they filed over 55 tariff change filings in the last year and a half. I don't know who's keeping score but I think that beats the California ISO's record.

MISO has killed the liquidity that Cinegy has, once the most liquid point in the industry by its refusal to post the ATC values necessary to the market to trade its location. Its huge export fee has also impacted market liquidity by pricing generation moving in areas outside of

MISO out of the market. Another strong check for PJM.

In closing, I want to reaffirm Illinois Power's commitment to joining PJM as a transmission owner or as part of an independent transmission company. This is reflected in the MOU with PJM filed yesterday.

There's one additional thing I want to make clear. Illinois Power has already spent $6.5 million to leave MISO. Another $7.5 million to develop Alliance. Our net income for transmission is only around $7.9 million a year. We've already spent almost two years' profits in pursuit of the Commission's goal, and the path previously approved by the Commission, and then reversed. Before spending any more money, we simply need a final decision from FERC. Thank you and I look forward to your questions.

CHAIRMAN WOOD: The $6.5 million you would have gotten back, right? Is that the same identification of money that we're talking about from the prior order?

MS. PATTON: Yes, potentially would have gotten back.

CHAIRMAN WOOD: You didn't have a legal right to say that, but I'm just making sure I was counting the right dollars. Any questions for Ms. Patton?

(No response.)

CHAIRMAN WOOD: Thank you. Yes, sir. Mr.

Rainwater.

MR. RAINWATER: I'm Gary Rainwater, President of Ameren. Just to give you a little bit of background on our company, Ameren is a Missouri and Illinois utility company.

(Slide.)

We have almost 12,000 megawatts of load, most of that in Missouri, about 8,000 in Missouri, 4,000 megawatts in Illinois. We have a fairly extensive transmission system and we are tied to 28 other companies which I think is probably more than most or possibly any other utility in the U.S. We have elected to join the MISO as a part of Grid America as part of the independent transmission company.

(Slide.)

Our reasons for that are fairly simple. Actually, I have not been a part of the negotiations that have gone into that for the past year. I think most of the other folks at this table have, although if you do want some background on that, Dave Whitely is here, who has been a part of that. But the number one reason for us to go to the MISO is your April 25th Order which we really saw as the culmination of all of the negotiation that's gone into the Alliance and the creation of Grid America for roughly the last year-and-a-half. So we put a lot of work, time, effort, and money into creating that organization. As Betsy said, collectively we have invested about $90 million. We saw your April 25th Order as the most direct way to complete that work and really a green light from the FERC to go ahead with that. The second reason also important to us is the fact that we are very much a midwest company. We've been a part of the MAIN Reliability Region since it was created. We trade not only with companies to the east, but with companies to the west of us. Most of those companies will be a part of the Midwest ISO.

We are somewhat troubled by IP and ComEd moving to the PJM because looking at this issue from a marketing point of view, they are good trading partners, but I would say not our primary market. So the seams issue that you questioned is an important issue to us, mostly from an economic point of view because of that high out rate, the $6.00 per megawatt hour certainly is an impediment for us to move power to that market. It also is a seam within Illinois, which is an open access state, and it creates a seam now for us to be able to get to the retail market in Illinois. So that's a concern geography for us and the topography of our transmission system really was the second major reason for us to go to the MISO.

The third reason is our acquisition of CILCO which also is an Illinois company and already is a part of MISO. And for us then to go to PJM as we're acquiring CILCO would create a seam within our company which we're certainly not interested in doing. And the last reason for us is that we think that all of our regulators, in particular the Missouri regulators, really favor our going to MISO. All of the other Missouri investor-owned companies are a part of the MISO, so for us to go to PJM would have created a seam within Missouri which the Missouri Public Service Commission would not like.

We thought at one time that Illinois would clearly have favored MISO, although that issue now is somewhat blurred. Our company would be in MISO now, IP coming in and PJM and a lot of smaller Illinois utilities would all be in the MISO. And last, we've all thought you would favor our going to MISO as well, particularly because of CILCO, the fact that CILCO was already in the MISO.

CHAIRMAN WOOD: Thank you, Mr. Rainwater. That's the eight members of the Alliance. Was there a ninth? We've got everybody. Mr. Winger?

MR. WINGER: Good afternoon. Thank you for this opportunity to address the Commission. I would like to give you an overview of the causes as I see them for the state's RTO selections, if you'll indulge me, my view on the balance of risks going forward. Then I'd like to discuss the issue that these selections raise under three headings because I think some slight drilling down into what we mean about seams and what SMD might solve and might not, could be valuable to you. So those three headings are: Market

Operation and Development, Transmission and Functional Control, and finally the ignored part of this as I've passionately related before, the ignored part of this equation, Transmission Investment Operation and Ownership. So I've tried to cover the implications for that as well.

(Slide.)

So an overview. In a sort of perverse way, I wonder if the sort of conundrum which you face today on this should give you some comfort. The selections it seems to me are driven by two types of pressure. One is a pressure that is associated with not having a single integrated coherent market structure across the whole region. And clearly people have spoken a bit to that. And the second is a pressure which is a result of the fact that companies have interests in not only transmission but also in generation and load serving. And the sort of comfort I think you might take from that is that you're already moving vigorously on both of those things with the introduction of SMD and your encouragement of further separation between transmission and market functions through things like ITCs and other initiatives. I believe you have an unenviable choice between approving the proposition

(Slide.)

which in my overview can work but it's likely to work with a lower level of overall efficiency. And finally on that one that looks untidy, and I sort of worry slightly about the untidiness of it, as going to the credibility of the whole RTO process which is a process that National Grid very much supports.

On the other hand, to reject this proposition could cause further delay, the benefits to the wholesale markets coming to customers.

(Slide.)

If you'll indulge me, I just wanted to tell you the joke that's doing the rounds very much, a very cruel joke to an Englishman, which is the principal difference between the RTO debate and cricket is that cricket ends eventually.

(Laughter.)

MR. WINGER: That's probably the most valuable part of my presentation, so I want to drill down into those three issues and relate that to the discussion between Phil and Jim at your last meeting which I thought was a very interesting one. There was a lot of debate about will SMD solve the problems that come out of this configuration in terms of market operation. I believe that probably SMD, looking very ambitiously at what SMD can produce in terms of widespread, seamless markets, will solve those problems. So I believe that under this heading, the answer ought to be yes. But I would recommend against implementing current

Midwest market arrangements alongside current PJM market arrangements.

In this footprint, it seems to be mixing ATC, scheduling and tech on the one hand, and RMP FTR on the hand. In the interim before SMD along this very complicated interface it's going to be problematic. So my suggestion on this is if you believe that it's right, in terms of the balance of risk to go ahead in this configuration, that you should approve it with the caveat that the companies that go to PJM start up on the Midwest arrangements by not giving that difficult market arrangement, but them move on to SMD, and I follow that up very much with SMD should be

CHAIRMAN WOOD: The first part of that was what?

MR. WINSER: As was partly the intention, anyway, in terms of the MOU that was filed yesterday, that you use the BridgeCo systems to start up those companies, going to PJM on, effectively, midwest arrangements, which is envisaged in the MOU. But what is a slight variant, and my advice to the Commission would be that you then run those companies, albeit with PJM oversight on those ATC-type scheduling and tagging type arrangements through until you can actually put an SMD.

CHAIRMAN WOOD: So you're saying skip day two and go from day one to day three?

MR. WINSER: I think that's right. Those are the issues I see in terms of market development and operation.

Moving on to transmission and functional control, this is where I believe that some more precision might be helpful from the last meeting. The RTOs, broadly, are doing two things: They are running the markets and they're doing transmission functional control.

SMD will not solve the transmission functional control issues, in my view, so the issues associated with planning, operationally planning and security coordination, will not be solved by the introduction of SMD.

In your Alliance and TransLink quarters, you've given us a way of helping this. You've given a split of responsibilities between RTOs and ITC on transmission functional control, which, in my view, very fairly balances the perceived issues on independence and supervision of scope, with the desperate need, in my view, to establish viable transmission businesses, so I very much concur with Jim's views of two weeks ago, that SMD doesn't solve the transmission function and control issues, but submit that if we did find a way of retaining ITC on both sides of this under common management, that ITC may well be a very good mitigator of the transmission and functional control issues that arise out of this configuration.

(Slide.)

MR. WINSER: On my charts you can see that I've had a go at a sort of Mickey Mouse sort of version of a rather simplified version of how this would work. But it reflects the fact that we have a firm intent in the west to have an ITC, but we don't have one in the east.

So I have contrasted, if you like, on that diagram, a world where National Grid can manage ITCs across that whole footprint and bring some help to the RTOs in working together across the footprint with one where we don't end up with an ITC on the east, because that's what's clearly currently in some doubt.

(Slide.)

MR. WINSER: Finally, on transmission investments and ownership, ITCs give a great opportunity for bringing desperately needed management focus and financial focus -- no capital rationing, get the dollars spent on transmission and the financial firepower to transmission.

And I'm concerned that that ITC prospect may shake out of the model as we go through this trauma, therefore, I'm absolutely delighted with the Grid America proposition. It's very much modeled on the Alliance, TransLink orders. It's about that functional issue, but also about building a transmission business, and ultimately giving the opportunity for divestiture.

So please support this proposal, the Grid America proposal. You won't be disappointed. We will, together, come forward with a model which will dramatically improve the management transmission, bringing active management and vigorous investment into that sector. It would be a terrible shame if that opportunity is lost.

And Grid America is an opportunity to go forward with that. I believe that proposition is a great one for both customers and shareholders, and you don't find many of those around. I would obviously commend it.

I'd like to thank First Energy, Ameren, and NIPSCO for keeping the faith with us, and Jim and his management team for having the vision to help that come to fruition, at least as far as the MOU that was filed.

On the other side of the equation, we have had very serious discussions with those proposing to go to PJM, and, indeed, with PJM management. The MOU is pretty evenhanded between whether there's an ITC or not an ITC.

It states a preference for an ITC, but the parallel paths, let's be clear, are do an ITC or don't do an ITC. We have signed that because we're still very keen to do an ITC, but there is very clearly, in the next 30 days, a debate about whether to do an ITC.

I passionately believe in this concept, as you know, and so I would very much urge the Commission to throw its weight behind retaining the ITC concept, both sides of the seam, if you like, not only to mitigate the transmission functional control issues, but to keep alive over a very large footprint, our dream as to how transmission can be revolutionized to the benefit of the customer.

I'd also like to finally say that I think -- and Dan's not going to thank me for this in a second -- Dan and Chris Miller have done a super job in helping us think forward. I think that's been a great success in terms of releasing those members of Staff into a non-decisional role to help things move forward.

The bit he won't thank me for is, I think you should really -- I would really suggest that you should continue that to get to this thing through to fruition in whatever form. Sorry, Dan, Chris.

(Laughter.)

MR. WINSER: Thank you for that opportunity.

CHAIRMAN WOOD: That's helpful, thank you, Nick. We also have Jim from MISO and Kenneth from PJM here as well. I guess someone just asked you, any reactions? As the new servants of the people, you've got a little bit bigger charge than you did a few weeks ago.

Any reactions to what you've heard today?

MR. TORGESON: I think my initial reaction is that I agree with Nick, because I made the comments two weeks ago about reliability. The view that we have is that today, reliability in the middle part of the country, and security coordination is done by me, and as you start making these switches, that go away.

That is a concern we're going to have, as to how security coordination is going to happen. People talked about their natural trading partners, and, yes, a lot of the trading goes between AEP, ConEd, and Illinois Power. There are also loop flows that go throughout the entire system that have to be managed.

And one of the characteristics of Order 2000 was to internalize those. So that has to be brought into consideration when we're looking at this.

So the reliability isn't just on the basis of who you're selling to; it's also on where the power is flowing. The other thing that we discussed before is the rate issue, and through- and out-rate on the Midwest ISO is very high right now.

We're discounting it to make sure we transact business, and we're doing so successfully at this point, but we've also heard from some transmission owners that they believe that it's too high. It's causing their business not to transact as much as they would like and they would like to see it reduced even further.

We're looking at ways, but we also have an obligation to maximize revenue to all the transmission owners within the Midwest ISO, so we have a balancing act to perform. That, clearly, to me, is an issue that has to be dealt with.

I think the planning is another aspect. Some people touched on it, but didn't get into it. How are we going to plan the system when you have this marbled group in our RTO that's going to require a considerable lot of coordination?

I think that once we have the single common market up and running, these are still the issues that are going to have to be dealt with, the planning and the security coordination. We can have agreements with PJM, which I am confident we can work out, but you're still going to have a seam, and the seam is going to be different and more complex than it could be.

MR. LAUGHLIN: My feeling is that we can have a single regional market up. I'm not sure what the timeframe is. Maybe it's three years; maybe it's a little bit longer. I actually had the picture that I have at least given the Commissioners, that a joint and common energy market is the answer.

What we're talking about now is the transition period. That's what we're going to look like for a couple of years until we get there.

That final end solution has single markets, and that does internalize everything we've been talking about. That does resolve the issues we've been talking about.

But the transition really does have seams. All that we're really debating is the location and the movement of the seams. I know that PJM can manage the transmission reliably. We know we can do this.

We've looked at it; we've studied it, and an LMP system, which is a standard market design system, has a proven track record. It maintains the markets in harmony, really, with the reliability, with the short-term reliability.

But the joint and common energy market, the final solution, will significantly enhance the reliability of the whole region. Just look at the fact that you're really going to have the one organization running and coordinating a large area, versus -- and I'm not sure how many there are today, but there's got to be in the neighborhood of 15 to 20, trying to coordinate, and as you get down to fewer numbers of organizations performing that coordination, the coordination is going to be better.

I really do believe that what we've heard today, the people that want to join PJM, the fastest way for them to get wholesale markets up, is to join PJM. Those markets are going to be, if not the standard market design-market, they're going to be very close to that.

They're going to be LMP-based. They're going to have all the principal characters of the standard market design-market, and they will evolve into that standard market design-market.

But I think the biggest take-away is the picture of a joint and common energy market with a single day-ahead market, a single real-time security-constrained dispatch over the entire market, a single real-time energy market.

And all the things we are talking about are to get to that point. If you look at it, the critical path to doing this, from my point of view -- and I'm a markets person; I build markets -- my critical path to get that --

and we're putting together a plan right now with MISO to do that -- is to get the MISO and SPP market up. We've got to get them together. They've got to develop their market. They've got to get that up and running.

We can probably do the joint and common energy market, 12 to 18 months later. We're going to come up with a critical path, and we'll report that back to the Commission, but that's really the solution to everything.

CHAIRMAN WOOD: Goodness, I don't know where to start. Let me hop back to Nick. I heard this, I think, as early as Craig, too, that there is a 30-day contract to do what in PJM, based on last night's MOU? Betsy might know better.

MS. MOLER: There's a 30-day --

CHAIRMAN WOOD: Is Dayton on that, too?

MS. FLANNAGAN: We haven't signed.

MS. MOLER: There's a 30-day period of time to develop an implementation plan for how to fold Illinois Power, Commonwealth Edison, and AEP into PJM. There is a parallel track that will be our business discussions with National Grid, whereby we will determine to actually form the ITC or not.

If we come to a successful conclusion, great. If not, then we will join, and there is a commitment in the MOU to join PJM simply as TOs without the ITC.

AEP also had previously entered into its own MOU with PJM. It was sort of the initial domino. Nothing is very explicit in the MOU; nothing in the current MOU is intended to adversely affect that MOU, but it makes very clear that we are committed during the 30-day period, and our first preference is to work out something acceptable with National Grid to form an ITC under PJM.

CHAIRMAN WOOD: How would that work if you're an ITC for half of these in MISO? You would take the legacy system that you all developed for the Alliance and work both things on day one?

MR. WINSER: We would use the BridgeCo systems slightly differently on each side of the interface. The BridgeCo systems on the west would be used to get to roughly the functional split that came out of the TransLink and Alliance orders.

We've worked out plans with Midwest ISO on how to get best use out of the BridgeCo systems, how to get there as quickly as possible. On the eastern side, we would get up and running, using those systems, with a very thin PJM oversight, initially, and then PJM would gradually take on functionality towards what's termed Day Two in the agreement.

To the extent that PJM then adopts quite a lot of the functionality quite quickly, and the ITC works on the

Day Two functionality and the MOU, and SMD comes in sometime thereafter as the Day Three implication.

CHAIRMAN WOOD: Has NERC weighed in on the security and reliability issues with either of the interconnections?

MR. TORGESON: Not that I'm aware of.

VOICE: They wouldn't until the reliability regions filed a revised security plan.

MR. LAUGHLIN: NERC is actively debating the model and putting names on various things. In actuality, the RTOs are going to assume a number of the functions that are being defined by NERC. So we're going to be maybe doing two or three of the things, which possibly different people do today, but that's an open debate.

COMMISSIONER BROWNELL: I'm glad that NERC is redefining the world, and putting names in boxes and stuff, but at least three of you here today have raised reliability and security issues. Almost every state commissioner raised it.

I'd like to hear them weigh in on this, because I think that it's great, that if people are working on these relationships, ultimately we have to address what is appropriate.

I don't know about my colleagues, but I need to get a whole lot more comfortable than I am today.

CHAIRMAN WOOD: I'd like to get that kind of independent assessment on reliability issues here, about the configuration we are splitting. Since the early days of the Alliance, we split ECAR into different regions. So the issue is probably not new, but I'd like to just know what they are, if they are, if there is anything we need to worry about or not.

Off the top of my little engineering brain, I think they are something I need to worry about. I'm just not sure if something like grid being the glue over the top of that for the transition period is enough to kind of bubble-gum and paper-clip this thing through this and be into this map, or if that's still a problem.

MR. CANNON: Just a question for clarification, Nick. On the second to the last page where you have National Grid sort of acting as this bridging mechanism, is that what's the subject of the MOU, or is that sort of a different proposal?

MR. WINSER: That's if. The MOU is really a fork in the road. If the parties decide to go ahead with an ITC with National Grid as managing member, that would form that National Grid continuum across the footprint, which may help mitigate some of the issues.

But I would reiterate that it seems to me that SMD does solve the market issues, but doesn't solve the transmission functional control issues. So, that isn't just an interim issue.

MR. CANNON: I thought you said that involved skipping Step 2 under Betsy's formulation.

MR. WINSER: That diagram, in itself, doesn't require that, although as a separate observation in terms of the operation of the markets, I would say that over such an intricate interface, running the current Midwest, current PJM "market models," in quotes, as elected, seems to me to be problematic.

MR. CANNON: Is that also the subject of these MOU discussions? It seems to me it's sort of talking about two ways to address a very complicated scenario for some period until SMD comes in.

MR. WINSER: Yes, the MOU does lead to a discussion of the use of the BridgeCo systems to go forward in the interim. The MOU does envisage, though, going to the Day Two arrangement, which I do have some concern about in the sense that that will put the midwest and PJM current market arrangements in place across this rather confused boundary.

MS. MOLER: Mr. Chairman, can I comment on that? I don't mean to be cavalier, and I say this, having thought about it a lot.

But right now, we have PJM in operation, and there are seams all around PJM. And we transact across multiple borders every day. That doesn't threaten reliability, so the fact that you have different market models, different places in the country, to me, while it is not ideal, it's not the desired end-state.

I don't really worry about reliability from that point of view. We would have a PJM market expanding. It will interface with the companies that are in MISO, if MISO is the single operator.

But it happens today with lots more companies than that.

CHAIRMAN WOOD: You've got ECAR and you've got MAIN out there doing their job. Do they just keep doing their job until we fold those biddies into what? Into what? The mega RTO?

MS. MOLER: Our MOU -- and look at the appendices, you know -- we envision, if there is National Grid, that they would become the security coordinator. If we do form an ITC, we envision that they would be the security coordinator, and they would assume a lot of the MAIN functions.

But, you know, transmission owners will still be there; we still have control rooms. Eventually, they, too - - we will get some synergies by collapsing the control rooms. It's a massive transition issue, but I don't think it is a reliability issue.

I think it is less worrisome than the situation we have today.

CHAIRMAN WOOD: I don't think I disagree. I guess my standard is, what is the world that we could get to? And you guys maybe have chosen differently, and if it's not that much quantitatively different, then I'd probably just -- I'm probably just going to walk and say, fine, let's go.

But if we've got the opportunity to say maybe you need to dance with him and you need to dance with her, that will make this thing 50-percent better from a reliability point of view than what we've got today.

Then the choices today -- clearly, the choice is, as awkward as they may look on the map, are better than not having any choices at all. I agree with that, but I think that's a pretty low baseline, and I think anybody ought to be able to jump over anything you do. But let's set the standard high for these good markets.

MS. MOLER: The standard, to me, is a standard market design. Clearly, you have to delineate who has the security coordinator or whatever the new NERC word is going to turn out to be.

CHAIRMAN WOOD: Reliability authority.

MS. MOLER: Reliability authority/functionality.

I think it's well worth the Commission's time to think about and come to a conclusion based on the public interest on who has that function in the end state.

I understand that, but one of the questions is, you know, do these decisions represent a threat to reliability, particularly if the decisions are implemented on slightly different timeframes until you get to the implementation for the standard market design.

We're going to be better off, once we get these two entities up and running. We will be even better, better off, once you get standard market design with the security coordination responsibility delineated there.

MR. BAKER: Commissioner Massey, two weeks ago, called us the backbone of the EP system. As such, I wouldn't go lightly into any decision, if I thought reliability was threatened.

I'm very comfortable that this can be worked through. I'm also very comfortable with PJM's desire to work through any issues around seams. It becomes incredibly important to us to make sure it happens, not just to put off thinking about it until SMD, because we're going to end up with seams, no matter which place we go.

We're going to have seams with a lot of people who are in other systems, or aren't in RTOs. So this is something that has to be done now in anticipation.

And I don't think we should make changes in the decisions, as much as really identify if there are any reliability concerns. As I say, I don't believe there are, and if there are, figure out solutions to those, so that it works out all the seams.

CHAIRMAN WOOD: What would help me -- and it's my hope, particularly since Bill isn't here today. I would have wanted to give you some feedback from all of us today. I think we can certainly give you a little bit more crisper before we close this out.

What I would like to do is, between now and the next meeting, which is when I hope we could just get on with this, have Bill give his input as well -- is have the member companies, but particularly the two of you all and NERC and Grid as well, sit down and talk through some of these reliability issues.

And then Jim can write out some concerns to the state commissioners there with some quantification of that. And I think if you could share that with these other folks, and with the NERC folks, it would help me.

I'd just as soon call NERC up to bat here and say, you know, here's the ball, which way are you going to go with it, and see what their take is on that deal.

I understand your concerns. They make logic to me. I want an independent, third party in on that, too.

If I were to just tip my hand today, based on what I thought and what I've read, my thought on this still is -- my lingering concern is with the Illinois companies and if that is the appropriate fit.

I understand why. It's a company, and for your state, actually, I appreciate, Ms. Patton, your candor. I don't think it helps us when everybody kind of sweet-talks around things. You just kind of cut to the chase about this gets you to markets faster.

I wish maybe that would have happened long before I came to this Commission. I might have been able to pick another job in my life.

But we aren't in markets; you all want to get to markets; you say you do. I'll take you at your word, that the PJM ticket probably looks like a faster way of getting there, and I'm sympathetic. I want you to get where your state legislature wanted you to get.

The rest of the companies, First Energy, quite frankly, it is a little -- I mean, I looked at the topographic map as well, and I think that certainly it's a little easier. It's not quite as pronounced for me, the concern about First Energy going west, as it is about the Illinois companies going east.

As to the rest of the choices, I don't have anything, and I don't anticipate having anything that I would bring up about those choices. I'm not sure that I will about the Illinois companies or FE, either, but these are the ones that I do have concerns about, and my concerns really tie back to Order 2000's issue on configuration, which was my original concern about the Alliance Company, too, as a stand-alone, that it rests with those three companies.

So I think that anything that can address the concerns about the integration of those two grids, your two, and then the FE grid over here on the east, with the interconnections you all have chosen to go with, and what implications that has for the rest of the midwest market, would certainly give me some good data that I don't quite think I have.

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Certainly the trading patterns are important. I'd like to hear from the NERC folks what the actual physical flows are so I do understand among the eight functions was to internalize loop flows. I do want to understand where the loop flows are, and I understand we got some data on that last week or last time we met from -- who was that from, Phil? Phil and Jim both I think. I'd like to relook at that.

But the physical loop flow information, if we are going to accomplish what we wanted to accomplish with Order 2000 on RTOs, it will end. There may be a few overtime rounds, but it will end, that we really do base it on some factual information that we can say really did address Order 2000 as opposed to just expediently get you folks out of here so you can get down to putting your markets together, which is the endgame here. That's where I am.

The three of you all want to get more comfortable with that, and I want to understand where the NERC folks weigh in on the reliability issues. And then importantly, I think I did hear there is a potential glue role that, Nick, you company could play in some of this that might be workable in my mind, that I hadn't thought through until you laid that out today.

COMMISSIONER BROWNELL: Maybe we could add to the list, just keep us posted. Maybe Dan can do that in his new missionary role, about the discussions about the two tracks, ITC, no ITC. That would be helpful to understand where that is as we strive to incorporate that into some of our thinking as well.

So we've all learned to know and love Dan for his role in the MISO developments. We're going to learn to know and love him well in the PTU development. When is the state commissioners transcripts? When will that be posted?

CHAIRMAN WOOD: Ten days from yesterday.

COMMISSIONER BROWNELL: You might want to just take a look at that and see what concerns they've expressed.

COMMISSIONER BREATHITT: This has been very useful to me. There's not a lot of secret about where I've been on these issues all along. I was comfortable with letting ERCA go forward and getting to the super regional rate. I think there's a lot of merit in the decisions that all of these companies have made for market reasons. I do think there is something to be said for being able, for those companies that chose to go to PJM to get up and running quickly.

I am pleased that I don't see empire building in these discussions, and I hope that doesn't creep into it, because I think that's important also. And I also know that we've got NARO, who is the successor to NERC, that's going to be around and may be providing a very important reliability function going forward, even as markets are being restructured and standard market design will be implemented because the Chairman's keeping all of our feet to the fire with very good reason, as we've heard again today.

So as I look at this map, which is the one that you passed around, I think it's doable. I think that Nora, you and Pat, though, have asked some important questions, that if I'm hearing you correctly, you want to have more discussion on at the next meeting.

CHAIRMAN WOOD: I'd like to actually have us give everybody firm feedback.

COMMISSIONER BREATHITT: And our thinking at the next meeting.

CHAIRMAN WOOD: And just kind of wrap it up.

COMMISSIONER BREATHITT: I think we need to do that, because I've heard companies saying we just can't spend any m ore money right now, and I think we need to do that.

CHAIRMAN WOOD: We will.

COMMISSIONER BREATHITT: So that's sort of where I am.

CHAIRMAN WOOD: Good. That helps. We'll talk with Bill as well on these configuration issues and NERC. I want to ask MISO, PJM to take the world as it would be if these folks' decisions all stay where they are, and lay out for us what would be your next day's effort. In other words, what do you do on day one to start making this thing work together?

I want to know where the role of national grid as the glue for both sides of the divide here can be a constructive way to bridge between now and the implementation of the Commission's SMD and I'm still not sure -- I want to get comfortable that this is more than just a pretty PowerPoint. I get the e-mails every week and all that stuff, but this can be a whole lot easier for me, this whole discussion we've had here gets a whole lot easier for me, if in fact I know that this really is an outcome that is a single market, is a single security coordination, is a single security constraint market dispatched through a single energy market, and all the things that we're envisioning it to be.

Betsy, I think I've heard you say it before at the beginning of the day, the endgame is the SMD. All the rest of this stuff kinds of falls into place afterward, and I think you're right. I just want to make sure that you're right. So we've got a lot of things to do to make this happen. And quite frankly, sitting here banging heads with you folks for another two years is not my idea of a good time or yours.

I want to give you a pat on the back and wave you off into the sunset as you and your happy customers go that way. But I just want to make sure I did my due diligence before you get there.

I've got some fundamental concerns about this process, but I probably should ask those as a state regulator, but I still have an agenda, and I want to get there, and I think I came with a few more answers. We'll have the staff follow up with specific detailed questions as we digest this stuff this afternoon.

My expectation would be that in the July 17th open meeting of the Commission, let's think about before everybody wastes a lot of plane ticket money to come back, but we'll find out who we need to be back here and be in touch with you before July 4th about how we want to script that for the next meeting.

MS. SHELTON: Cindy, anything you want to add here?

(No response.)

CHAIRMAN WOOD: Anybody from the Alliance companies or Nick want to add anything here?

(No response.)

CHAIRMAN WOOD: Thank you gentlemen for coming down today. Before we close out the meeting, we need to transact a little business for our closed meeting. I'd like to postpone that until tomorrow. I need to ask the Commission to waive the Sunshine Act requirement to give seven days' notice of the meeting to agree to have the closed meeting tomorrow, June 27th, between 12:00 and 5:00 p.m. at Hearing Room 5, with specific time to be posted on the Web site and to incorporate by reference of prior notice general counsel certification that the meeting can be properly closed.

So it'll basically be a shift of our meeting schedule for right now to tomorrow afternoon at a specific time that we will post.

COMMISSIONER BROWNELL: Aye.

COMMISSIONER BREATHITT: Aye.

CHAIRMAN WOOD: Aye. Meeting adjourned. Thank you.

(Whereupon, at 3:20 p.m. on Wednesday, June 26, 2002, the meeting was adjourned.)

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