BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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In the matter of: :

PRICE FORMATION IN ENERGY AND :

ANCILLARY SERVICES MARKETS : AD14-14-000

OPERATED BY REGIONAL :

TRANSMISSION ORGANIZATIONS AND :

INDEPENDENT SYSTEM OPERATORS :

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Room 2C

Federal Energy Regulatory Commission

888 First Street, Northeast

Washington, D.C. 20426

Monday, September 8, 2014

The technical conference in the above-entitled matter was convened at 8:46 a.m., pursuant to Commission notice, when were present:

FERC COMMISSIONERS:

ACTING CHAIRWOMAN LaFLEUR

COMMISSIONER PHILIP MOELLER

COMMISSIONER TONY CLARK

COMMISSIONER NORMAN BAY

FERC STAFF:

WILLIAM SAUER, Presiding

MICHAEL P. McLAUGHLIN

ARNIE QUINN

JAMIE SIMLER

EMMA NICHOLSON

ROSHINI THAYAPARAN

JOSHUA KIRSTEIN

BOB HELLRICH-DAWSON

DAVID REICH

LAUREL HYDE

MR. DAUTEL

PANEL I: CAUSES OF UPLIFT

GUILLERMO BAUTISTA ALDERETE, California Independent System Operator Corporation

PETER BRANDIEN, ISO-New England, Inc.

TODD RAMEY, Midcontinent Independent System Operator, Inc.

JOSEPH BOWRING, Monitoring Analytics

ROBERT PIKE, New York ISO, Inc.

STU BRESLER, PJM Interconnection, L.L.C.

DAVID PATTON, Potomac Economics

RICHARD DILLON, Southwest Power Pool, Inc.

PANEL II, Part 2, IMPACT ON MARKET PARTICIPANTS

JOHN ROHRBACH, ACES

MARK SMITH, Calpine Corporation

BRIAN FORSHAW, Connecticut Municipal Electric
Energy Cooperative

IVAN KIMBALL, Consolidated Edison Co. of New York

MICHAEL SCHNITZER, Entergy Nuclear Power Marketing, LLC

WESLEY ALLEN, Financial Marketers Coalition

PETER FULLER, NRG Energy

ELIZABETH WHITTLE, Retail Energy Supply Association

PANEL III: PRICE TRANSPARENCY AND EVOLVING MARKET DESIGNS

BRADFORD COOPER, California ISO Corporation

BRIAN FORSHAW, Connecticut Municipal Electric
Energy Cooperative

SUSAN POPE, Electric Power Supply Association

WILLIAM BERG, Exelon Corporation

MATTHEW WHITE, ISO-New England, Inc.

TODD RAMEY, Midcontinent ISO, Inc.

JOSEPH BOWRING, Monitoring Analytics

ROBERT PIKE, New York ISO, Inc.

STU BRESLER, PJM Interconnection L.L.C

RICHARD DILLON, Southwest Power Pool, Inc.

PANEL IV: BROADER PRICE FORMATION ISSUES

SUSAN POPE, Electric Power Supply Association

JUDITH JUDSON, Energy Storage Association

HARRY SINGH, J. Aron & Company

DAVID MOHRE, National Rural Electric
Cooperative Association

ELIZABETH WHITTLE, Retail Energy Supply Association

DAVID PATTON, Potomac Economics

BOB WEISHAAR, PJM Industrial Coalition
and PJM Load Coalition

Court Reporter: Jane W. Beach, Ace-Federal Reporters, Inc.

P R O C E E D I N G S

(8:46 a.m.)

MR. SAUER: Welcome to today's workshop on Price Formation in Energy and Ancillary Service Markets Operated By Regional Transmission Operators and Independent System Operators---Regional Transmission Organizations and Independent System Operators.

I want to thank all the participants for being here today for what I'm sure will be an informative and lively day of discussion. I also want to thank the Chairman and the Commissioners for being here today.

This workshop is part of the Commission's recently announced efforts to explore improvements to market designs and operational practices in order to ensure appropriate price formation in energy and ancillary service markets.

We will use the time today to identify and discuss the technical, operational, and market issues that give rise to uplift payments and the levels of transparency associated with uplift payments.

We will also preview the scope of the remaining price formation topics which include offer-price mitigation and price caps, scarcity and shortage pricing, and operator actions that affect prices.

Prior to describing the four panels and covering

several housekeeping items, let me turn to the Chairman and Commissioners for opening remarks.

Chairman LaFleur.

CHAIRMAN LaFLEUR:: Well good morning, Will, and thank you all for being here. You can always tell a topic is really hard when the Commissioners are sitting at the little kids' table, and all the smart staff are sitting at the big table.

(Laughter.)

CHAIRMAN LaFLEUR:: But I really want to thank every one or coming, especially the panelists, many of whom traveled over the weekend to be here.

It's a very high priority for the Commission right now to try to ensure that competitive markets are structured and operating to sustain reliability and just and reasonable rates when our electric grid is going through so many changes in resource mix and operation, and when we know we need investment in new resources and retention of existing resources to sustain reliability.

That means the markets have to be structured and operated to send the proper price signals to reflect actual market contingencies so people can make the right investment decisions.

I was talking to Mike Schnitzer earlier at the Tech Conference last September, particularly the final

panel. Many people commented that we couldn't look at capacity markets in isolation because so much of the revenue came through the energy and ancillary services markets, and we should take a broader look. And today is the kickoff, or after the staff paper, the kickoff of the workshops on that topic.

I just have two requests to the panelists on all the panels. The first is to be as concrete as you can in describing the effect of uplift on the market and on you. Try to stay out of just the economic theory, writ large, but how does it actually work? What impacts does it have on the market? And as clear as you can, and any recommendations you have for the Commission. In a topic this complicated we're better off if we kind of keep it real.

My second, harder, request I think is to try not to use too many acronyms. I was reading the prep materials last night. Possibly I was just in a bad mood because the Patriots lost to Kurt's Dolphins--

(Laughter.)

CHAIRMAN LaFLEUR:: --but it was striking how acronym-rich this area is. And every RTO and ISO had a different set of acronyms to describe basically the same thing.

So if you can appropriately use the term "uplift," please try to spell out the terms, except the

names of the ISOs and FERC. I think we're good with that.

(Laughter.)

CHAIRMAN LaFLEUR:: So thank you very much. Tony?

COMMISSIONER CLARK: Just good morning and welcome. This too is my first--actually, first chance to be here at the little kids' table, and I swear even the seats are lower--

(Laughter.)

COMMISSIONER CLARK: --over here. No, it doesn't go any higher.

(Laughter.)

COMMISSIONER CLARK: But thanks for being here. This particular tech conference and set of tech conferences are some that I've been looking forward to, in particular these issues of proper price formation within our markets that really came forward especially within the last year with some of the pricing that we saw and the impact on the market participants.

So I think it is particularly timely, and perhaps one of the more important efforts that the Commission is going to undertake this year as we move forward not only in relation, as Cheryl said, to looking at the capacity markets but looking at the functioning of the energy markets as well because they have such an important impact.

So with that, I'll turn it over to Norman. Again, thanks to staff for putting together an excellent briefing book, and to all our participants who traveled over the weekend.

COMMISSIONER BAY: Thank you, and good morning everybody. In in particular want to thank staff for putting together such an interesting and timely technical conference. I looked at the different panels today and I just think you are teeing up some great issues for us to be thinking about.

I also want to thank the panelists for coming here today. And I look forward to hearing your remarks as we focus on this issue of uplift and transparency, price formation in energy markets. These are obviously very big and important issues, so thank you.

MR. SAUER: Well thank you very much, Chairman LaFleur and Commissioners Clark and Bay, and thank you for letting us borrow your seats today.

(Laughter.)

MR. SAUER: We promise it's just temporary.

(Laughter.)

MR. SAUER: As I mentioned today, there are four panels. Panelists submitted background briefing material in advance, allowing us to skip the formality of opening statements and move straight into questions, into a

question-and-answer format.

All materials received have been posted to the calendar pages on ferc.gov and will be posted on E-Library under Docket AD14-14. Staff will be using the contents of its recently released paper on uplift to help frame certain issues and lead the discussion.

Staff views today's workshop and the entirety of the Commission's efforts on price formation to be the beginning of a discussion that will help inform the Commission and industry.

On the first panel, representatives from Regional Transmission Organizations and Independent System Operators, as well as representatives from the Market Monitoring Units, will discuss drivers of uplift in their RTOs and ISOs.

On the second panel, representatives from industry, including power suppliers, load-serving entities, and financial marketers will discuss how uplift payments and charges impact their participation in energy and ancillary service markets operated by RTOs and ISOs.

On the third panel we will hear from representatives from RTOs and ISOs, MMUs, and industry on recent market design changes that may address some of the causes of uplift. This panel will also explore potential options to improve price formation and enhance uplift transparency.

Commission staff will use the last panel as an exploratory session to discuss the scope of the four price formation topics contained in the June 19th Notice. Use of uplift payments offer price mitigation and offer price caps, scarcity and shortage pricing, and operator actions that affect pricing, and whether they cover the universe of price formation issues.

We will break at 10:45 to 11:00 and from 2:00 to 2:15. There will be a lunch break from noon till 1:00. We plan to wrap up at 5:15.

We have a lot of ground to cover in a short amount of time today. While the issues covered in each panel will overlap to some extent, we would like the panelists to keep their comments within the topics laid out for each panel.

If the discussion begins to stray outside the scope of the panel or outside the scope of the question, I may be interjecting to bring the topic back to the issue. Additionally, while this workshop is not for the purpose of discussing or hearing argument regarding specific cases before the Commission, we have provided notice of certain pending dockets in notices issued on August 14th and September 5th. Notice was provided out of an abundance of caution given the potential for ex parte communications. Please refrain from discussing any of the specifics of

pending cases and that will permit me from having to redirect conversation.

Let me close with a few housekeeping matters. Please do not bring food or drinks other than bottled water in the Commission meeting room. Turn off your cellphones if you have not already done so. There are bathrooms and water fountains behind elevator banks on each end of the building. For panelists, if you would like to be recognized to speak, please places your tent card up. Be sure to turn on your microphone and speak directly into it. When you are not speaking, please turn off your microphone to minimize any background noise.

Finally, because we are addressing six markets with different labels for uplift, please define any acronyms you are using, or avoid using them where you can. The Chairman will certainly appreciate it, as will we all.

Thank you, panelists, for being here, and everybody for traveling. I know it's Monday and you all interrupted weekend plans, and we certainly appreciate everybody taking time for what I hope is going to be a good discussion today, and I hope we learn a lot.

For this first panel, the goal of the panel is really to explore the drivers of uplift. Certainly we understand that there are a lot of technical, market, and operational drivers for uplift and that to some extent,

especially when you're talking about say voltage constraints or nonconvexities for that matter, there are a lot of programming or computational issues that can make it very challenging to solve the issue.

So in some sense the goal is not to directly get rid of uplift altogether, but to, say, minimize it and make it either more transparent through market pricing or data. For this panel, we certainly look forward to hearing about some of these market drivers and some of the challenges or limitations to making uplift more transparent.

Staff issued a white paper about a month ago, and we found a couple observations that will be informing some of our questions to this panel. One of those observations were essentially that uplift payments appear to be highly concentrated from both a regional perspective, or even a resource perspective, and that concentration was persistent year in and year out.

So what we saw is it wasn't uncommon to have say tens of millions of dollars paid to one particular resource every year. We also found that plants receiving over $5 million received over half the total dollars of uplift in all the RTOs with the exception of MISO. And sorry, Richard, we didn't have the data on the Day-2 market, so we didn't study it. So thank you for being here, though.

One of the other options, or one of the other

observations that we noticed is that uplift credits appear to be highly correlated with some market fundamentals, be it day-ahead and real-time price spreads, or energy prices in general. To some extent, that led us to believe that there are some drivers that may be outside of the control of the RTOs, and some that may be inside the control of the RTOs. Certainly we look forward to hearing from everybody about those relationships and whether we missed some relationships that are worth exploring as well.

Before we get started on questions and answers, let me just introduce the panelists real quick so everybody in the audience knows:

Guillermo Alderete from California--is it Alderete Bautista, Bautista Alderete, sorry? What do you prefer?

MR. ALDERETE: Alderete.

MR. SAUER: Okay. Peter Brandien from ISO-New England. Todd Ramey from MISO. Joe Bowring from Monitoring Analytics. Bob, or Robert?

MR. PIKE: Robert.

MR. SAUER: Robert Pike from NYISO. Stu Bresler from PJM. David Patton from Potomac. And Richard Dillon from Southwest Power Pool.

Thank you all for being here, and welcome.

For the first question, we'd like to hear about

some of the operational drivers or market or technical drivers that lead to uplift payments being concentrated on a persistent basis for particular resources.

And why don't we just start with Guillermo and go down the table, it that works.

MR. ALDERETE: Good morning. Thank you for having me. Let me start giving you a little background in terms of what the specifics of the California ISO is to putting contracts against other ISOs.

Without make-whole payments that are defined as bid-cost recovery, and also we have another fashion that is exceptional dispatch payments. These both account to what I would define as make-whole payments.

We have bid-cost recovery across markets we have for the day-ahead market and for the real-time market, and I would like to elaborate first in terms of the specific riders according to the market.

When we launched the market in 2009, we heavily relied on exceptional dispatches. Exceptional dispatches are out-of-the-market actions that the operators have to take in order to internalize how constraints that are not in the market. These exceptional dispatches are guaranteeing a payment of the bid or better. That is, either the bid, or the locational marginal price.

So when we start up a unit, we ensure that the

payments of the minimal load costs are covered. Now when we have the day-ahead market, the concern was that if we rely on exceptional dispatches usually they are after-the-fact to deal with the real-time operational challenges.

We worked in 2010 to address that, how to include that in the day-ahead market, and we came up with a constraint that we called Minimum On-Line Capacity Constraint. This constraint is cleared through the market. It's a market constraint, and it's trained to achieve somehow a better performance instead of exceptional dispatches.

This constraint is superior to exceptional dispatches but it doesn't reserve fully the pricing signal issue that we have. This is equipment constraint that requires that certain capacity needs to be online in certain area depending on the operation and constraint.

By the fact that this is equipment constraint, there will be no price signal in the locational marginal prices reflected. So even though it's internalized through the market, it is cleared through the market, it's considered and displaced according to resources, it lacks the price signal in the locational marginal prices.

This at least gets rid of the complications of having to dispatch resources on top of the day-ahead market solution.

Now it's important to say that if we don't have this constraint, potentially the cost would be higher because we would have to rely on exceptional dispatch that are inferior in that sense. That on its own drives some component of the bid-cost recovery that is related to the day-ahead market.

Now when we move into the real-time market, we also accrue bid-cost recovery, either because there were resources in the day-ahead market that now have to be basically appearing during the real-time market, or because the price fully doesn't support the commitment of the resources based on the real-time prices.

One of the complications that we have is that--and I believe this is more specific to the California ISO--we have WECC, the Western Electric Reliability Coordination criteria that basically means post-contingency we need to have the system in the secured state within 30 minutes.

We don't have explicitly a constraint in the market that achieves that job. While we have been doing these exceptional dispatches, positioning the system in such a way that we are able to have that capacity that within the 30 minutes we can achieve a secured state once a contingency occurs, we also have use of exceptional dispatches in order to position the system properly for the high loads.

Now we have done a couple of changes in the market. One of them is that in order to account for the required flexibility, we introduce a constraint. That is, flexible ramp constraint. In order to project accordingly resources to be able to meet a projected flexible ramp needs.

The other part is that we have this other contingency, criteria. So right now the market doesn't have that constraint. The only way we can achieve that is to position the resources basically manually in prevention of that state. The California ISO has been working on another enhancements that is going to be discussed in more details later on in terms of how we can achieve that through the market.

And I would say these are the main two groups I can classify the make-whole payments or uplifts that may occur in the market. And I can elaborate more on the specifics of flexibility of units. So I will just pass.

MR. SAUER: Before we move on, let me just ask a quick follow up. So you described a couple of different constraints. One is the minimal online commitment; another driver of uplift that you described was the 30-minute response from WECC and also the positioning.

Are any of those driving uplift payments to--do any of those result in uplift payments that are say

concentrated from year-in and year-out? Or what are the drivers of those concentrated payments?

MR. ALDERETE: Yes. We have estimated the effect of this constraint for the day-ahead market, the minimal online capacity constraint, and we estimate that for the last year it has been between 10 and 25 percent of the bid-cost recovery payments. That applies to the day-ahead market component.

In terms of the concentration, I have to say there are other interplays--and I can elaborate on that if you want. Specifically, the report issued by FERC posted two ideas where we have high concentrations of payments. One is in Northern California, and the other is obviously in Southern California. For the Northern California, I have to say it has to do a lot with the local nature of the system.

Specifically, for the Northern California what happens is that we have a very interesting dynamics. We have a set of units that are basically with the same characteristics. When you try to optimize that type of pool of resources, that puts a dynamics because you have exactly very, very similar characteristics of the units. What the market is going to do is to leverage on that to be able to handle the conditions of that area. It may happen that now you have a generator on, and because it's no longer needed it shuts down.

When the conditions change slightly such as when there is a load, for instance, 15 minutes later, now the market finds that it has another unit that has basically the same effectiveness, the same characteristics, and it can bring that unit on.

So what happens is that this leads to basically this flip flopping of units, because that is the most economic solution for the market to deal with based on the specific conditions that are dealing at that specific moment.

This area was problematic in that sense, that the flip flopping was causing the complication that at some point in time you run out of step-ups for the unit, because we have a specific number of step-ups for the unit through the day and we have to make sure that we don't run off the ability of the units.

The exceptional dispatches in that case was specific to avoid this flip flopping and basically stayed flat with some specific set of units. We work with these units specifically to try to break down these similarities and avoid the market to have this flip flopping, and I believe it has improved over recent months.

The conditions for Southern California are different but it still has to do with the local nature of the conditions.

First, you have a very defined static set of units. These units had a specific location that are problematic. Basically they are units that can help you to resolve the operational issues. And the typical instances, for instance let's say voltage constraints, that is a very local condition that there are only certain units that can do the job.

So when you have these complexities of addressing specific local conditions, the same resources that--the set of resources that are going to help you to resolve the issue are always the same.

So through this analysis we also found in 2011-2012 some refinements to our bid-cost recovery formula that was not that great. And that actually decreased the amount of BCR for that Southern California area.

MR. SAUER: Thank you for going into that.

MR. BRANDIEN: In New England, we've done a lot of transmission upgrades over the last 10 years, and that has significantly reduced the need for a lot of local run generation for transmission security constrained issues.

Early on we did have a lot of issues where we brought units on that weren't needed until post-first, or the 30-minute redispatch, or even post-second contingency to secure the system.

A lot of those problems have gone away, and what

we're dealing with now is more of a system-wide capacity, making sure we have enough resources online to meet our load and our operating reserve. And in New England we have a lot of sources that are large. Our DC connection with Hydro Quebec. We have two nuclear units that are over 1,200 megawatts. We have a combined cycle plant that can be up around 1,600 megawatts.

So for the size of New England, we're carrying a lot of operating reserve and making sure that operating reserve is in the right location so that we could activate our reserves and replace that lost energy becomes an issue that we have to deal with on a daily basis, and look to where those large sources are and where the operating reserve is on the system.

Most of our large sources are in the eastern portion of New England. A lot of our offline fast-start resources are in the west. So can we active, bring all the offline fast-start online and move it to the east? And there are times when we have to make sure we have enough operating reserves in the east.

Many of those units that we bring on we're looking for units that are somewhat flexible, but a lot of them are inflexible. They have a low eco-min, meaning the minimum operating level that they can be. So you can get a 600 megawatt unit operating at 60 megawatts. You know

you're going to need maybe 450 to 550 out of that unit during the peak hours, but at least you can bring it on and operate it down at a low level when it's not needed so that you're not depressing the price too much. But it's slow moving. So when you do need to start ramping up, you may have to ramp it up hours beforehand. So it's accumulating a lot of uplift.

We find that the units that have that low eco-min in the high output level, we tend to go to a lot in the operations of the system just to minimizing the impact on the market, and they end up accumulating a lot of uplift.

The other thing--and I see it throughout your report--is voltage. We have an area in western Massachusetts that tends to be a weak transmission system. It's saturated with static reactive support capacitors, and if we try to put more--the low-hanging fruit capacitors online, we end up with high voltage precontingency.

And we really need to operate some generation there so we can get the dynamic reactive support postcontingency.

The models know when to bring those units on. And as long as they're on and synchronized to the system, we have that dynamic reactive support. But it's not pricing the--it's pricing the, you know, the whole LMP is looking at pricing megawatts not pricing that reactive support of these

units.

And these units tend to be out-of-rate most of the time. The system is weak. We bring them on often. So there is a concentration of VAR support to those units, and you see it in your report year after year after year.

There is some transmission upgrades coming. I would like to have them already in place, but at least it's worked through the planning process; now it's got to go through the siting, engineer, construction, and implement.

So we do see some relief on the horizon for some of those voltage support issues that we see.

The other issue that tends to drive large uplift payment is either in the summertime when we have to bring oil on early so that we have it there during the peak hours, and it may set the price for those afternoon peak hours. But with their long min-run times, they may not set the price for many hours during their long run times.

They tend to be finicky units. And when we know we have multiple hot days coming, they don't cycle well. And we may have to hold onto them from a reliability perspective and not take them offline and then bring them back online. So they may be operating longer than their minimum run times just from a reliability perspective because we know if we take them off, the probability that they're going to develop a tube leak or some other problem

is high, just based on our operating experience with these units. So they can incur some uplift during the summer months.

In the wintertime, it's kind of a flip. Gas prices in New England, it doesn't take much for the gas prices to jump. You get a little bit of cold weather, you get into the 30s, it starts to climb. You get into the 20s, teens, it skyrockets.

A lot of our fleet is combined-cycle gas turbines. We really had a changeover of our fleet in the late '90s, early 2000s. Many of those aren't dual-fuel capable, and they have high minimum operating levels relative to their max output. And with high gas prices, they're out-of-rate many hours of the day with the high minimum operating level, and we quickly accumulate uplift charges on those units.

And when you look back at the last couple winters in particular, the winter of say '11, '13 and '14, you really see the spike in particularly January, maybe some days in February. So the fuel costs significantly play into that, and it goes back to the, let's say the inflexibility of the resources and our inability to push them down to a lower level, or to take them offline and then to bring them back online.

We have to deal with the minimum down times of

the unit as well. So we can't just bring them on for the morning peak, try to shut them down through the afternoon, then bring them on for the evening peak. We're left operating those units throughout the day.

Those are really the main drivers that I see in New England.

MR. RAMEY: Good morning. Just talking about the classes of uplift that we have at MISO that I'm going to talk about, one is our revenue sufficiency guarantee payment. This is the standard payment that is made to generators when our asset owners are following commitment instructions from MISO and the net of their revenues against their costs leaves them short of covering their full costs. Those units are owed an uplift payment.

Those calculations are made at the unit level on both the day-ahead and the real-time market. We also have another category of uplifts that applies to the real-time market. These are price volatility make-whole payments. These are essentially lost-opportunity payments that are made to generators when they are following closely our five-minute dispatch instructions. When their settlement comes out against their hourly settlements, there are opportunities for them to lose some opportunity payments, and price volatility make-whole payment is in place to compensate generators for that situation.

There's another category that applies to MISO, given how we allocate these costs, and that's a real-time balancing congestion. There's a circumstance in the real-time market where the amount of transmission transfer capability in real-time proves to be less than what was assumed and sold in the day-ahead market. Essentially there is a cost that's incurred to buy back those positions that were sold day-ahead to get the transmission in real-time down to what can be accommodated.

There's no source of funding for that kind of congestion. In MISO, those costs are allocated to load. So those are kind of the three primary categories of uplift we deal with at MISO.

The drivers themselves are really pretty basic. I think that the staff white paper covered in pretty good detail the most significant drivers of uplift in the MISO region. Those are the nonconvexities that we've talked about quite a bit, making commitment decisions just to cover the adequacy requirements of power balance constraint for the system, and for congestion management nonconvexities; just solving those kinds of issues can result in the requirement to make uplift payments.

Other kinds of drivers, again covered in the white paper, are more local constraint type issues. Load pocket issues, which essentially reduces the size of the

relevant market to a set of generators particularly within a load pocket that may be called upon to solve reliability issues within the pocket.

Local voltage support. For the MISO footprint that was in place for the period of the analysis of the white paper, the region was fortunate that we had very few load pocket issues. There was one--there's one small load pocket in the upper peninsula of Michigan that requires some uplift payments, but generally speaking pretty low load pocket issues, relatively low local voltage support issues in the Midwest. So not a huge driver of uplift payments compared to some of the more critical operating regions in some of the other RTOs.

So our approach at MISO to managing uplift is really just fundamentals. Start with, one, trying to minimize the uplifts that are generated really starts with looking at market administration processes. Inefficiencies in administration of these markets can quickly lead to accumulation of uplift payments.

It really starts with focusing on how you build and administer your day-ahead market. Any unit that is committed and finds itself running online, if there was a reasonable opportunity for that need to be seen and that commitment to be optimized in the day-ahead market, you're most likely going to be getting much more efficient overall

unit commitment outcome which tends to reduce the need for uplifts.

Those units that we do have to commit in real-time, we try to again minimize those costs by looking at the fundamentals of the processes used to make real-time unit commitment decisions, looking at improving the efficiency of the information delivered to the operators through the tools that we use.

We develop specific standards and expectations around headroom management associated with that real-time unit commitment process, and we have metrics in place that are reviewed on a daily basis. So daily performance reviews of unit commitment outcomes, including looking at those uplifts that are generated.

Some situations can occur that are out of the ordinary and may be driven by transmission outage that can lead to issues that are limited in duration, maybe three or four weeks in duration. If you don't see those kinds of issues quickly, you can generate quite a bit of uplift, millions of dollars of uplift, in just a few days.

So looking at those uplift totals every day helps us analyze what those drivers are and consider alternatives that may reduce uplift.

So with that, I think I'll turn it over to Joe.

MR. BOWRING: Thanks. So I was going to focus on

concentration, the concentration of receipt of uplift payments.

So in PJM, as we've been documenting for some time, there's been a high degree of concentration of uplift payments almost from the beginning of PJM. And as you identified as well in the staff report.

Even more relevant to the concentration, again as you pointed out and noted in the report, there are a small number of units receiving very large sums of uplift payments, which results in the concentration numbers.

There are two broad reason/areas where this occurs. One occurs in part for units turned on almost every day to at least in part support what's called "the PJM-ConEd Wheel." But the underlying issue is not the allocation, but it is the nature of the units. So the units have inflexible parameters, and again there's nothing wrong with those units; those parameters have been checked. They are a result of the physical nature of the units. It's not-- somebody's not doing anything wrong there; the physical nature of those units.

Part of the solution has to be, first of all, to better identify the reasons for dispatch. There's another area in PJM where the primary reason for uplift payments are reactive payments. Those are driven in significant part by relative gas and coal prices. So it's not so much the

absolute level of prices as it is the relative level of gas and coal prices.

And as we've seen, as gas and coal become more competitive--for example, coal plants against combined cycles--you see more uplift payments being required to coal units.

But in addition, we have inflexible parameters there, and as well we also had the issue of what's called "FMU adders" in PJM. But part of the solution is that this data and the information about these particular units is confidential.

You raised that point in the report, and we as well have very explicitly now recommended, because it has persisted for so long in PJM, that much more data be made available. In fact, we're recommended that all of the relevant data about units receiving large amounts of uplift be made public.

And the reason for that is to induce competition and to induce some market response. The fact that we've had the same units receiving massive amounts of uplift, or disproportionate amounts of uplift for a very long period of time, suggests that the market doesn't know about it, or is not reacting.

So there's no competition. There's no possibility of competition. In addition, it's not, as far

as I can tell, incorporated into the PJM's RTEP analysis, so they're not either transmission solutions or generation solutions.

For the reactive issue that we've seen recently, that reactive was carved out of overall uplift, made explicit, separately identified, and then allocated as reactive. It was required to be allocated to--effectively, to zonal load.

So simply by doing that, it brought it to everyone's attention much more starkly. It wasn't rolled in to all of the uplift. It brought it to the attention clearly of load, who had to pay it, as well as PJM who became much more aware of it.

So PJM we believe has reacted to that well and has operated the system somewhat differently in that area. But the common theme there is transparency, removal of some confidentiality of the data so that there can be transparency and can be competition.

And I think that really is the only solution that we can think of to this level of concentration. If it remains opaque, if it remains nontransparent, the market cannot solve the problem.

Thanks.

MR. PIKE: Thank you. I guess maybe to start, from New York's perspective, really focusing this

conversation on uplift as it relates to big production cost guarantees, and what we would call a day-ahead margin assurance payment. These are all both driven by ensuring that the price and schedules for resources are consistent. We want a resource to know he's going to recover his costs so that he has no uncertainty about following a schedule. So we want to provide these cost guarantees for that purpose.

In New York in our review of the uplift and those categories, what we see is about half of uplift is really being generated by economically committed units out of our market conditions--either our day-ahead or our real-time market outcomes. And really what this is saying is the resources--what are the lowest cost resources to pick?

They were chosen, but they're not recovering through intermarginal costs, non-energy costs. So not their start-up and their min-gen. What we see with those is they're going to be naturally distributed. There isn't a high concentration of that. We're just really trying to recover start-up costs and min-gen costs for these units to the extent the LMP revenues don't provide that additional stream of revenue.

The other half of uplift costs that we see generated are more for local conditions--local reliability constraints, particularly in some of our very heavily

congested areas in New York City and Long Island--looking at how to keep resources online and available.

We have numerous commitment constraints that drive units to be online to meet system needs, but that aren't necessarily dispatch needs. Some examples, you're heard voltage talked about several times. So post-contingency voltage support is a condition.

We also are trying to manage for loss-of-gas contingencies in these two regions, which requires us to have certain units online. Again, those are commitment constraints. So what we're incurring are start-up and min-gen costs to have these resources available, but they're not dispatch constraints. So it doesn't force a resource to be dispatched up and incur or set LBMP payments.

Those are naturally going to be more concentrated. They are looking at addressing very specific problems, and there's usually a very small subset of resources that we can call upon to address those needs.

To the extent those conditions will exist over an entire summer, those resources are simply going to be needed. We do see a lack of flexibility driving a lot of these costs. To the extent we can't cycle these units, they're certainly much older units and need to stay online so that they can be ready for the next day's system operation.

It is important to note that we make sure we capture those costs as local costs and allocate them back to the local region in which they're incurred. So they're not distributed across a broader region, but those cost recoveries are made within that local region where they exist.

Similar to some comments that Todd made, we do have a very active oversight of uplift throughout the markets, all sources of uplift in the market, with a daily operational review, looking at the previous day's settlement, understanding if conditions have changed, have we incurred a new type of uplift that we haven't, and what we can do operationally, what we can do through the markets to address those, lower the uplifts, and make sure things are incorporated back into LBMP.

But in many of these cases, they're not incremental energy costs that you're trying to recover. So it's a challenge, or even questionable whether you want to incur them through the LBMP revenues.

MR. BRESLER: Good morning, everyone, and thank you for having us this morning. It's a pleasure to be with you. I'm Stu Bresler from PJM.

Recognizing that you're spending quite a bit of time on your very first question this morning, I'll try to be brief and not be too repetitive. But similar to the

other ISO/RTO markets and what you're heard from the other ISO/RTO representatives already this morning, PJM does have a bid production cost guarantee as part of its Tariff for generation resources that operate at the RTO's direction and follow PJM dispatch.

We do have separate calculations of uplift in both the day-ahead and the real-time, wheel balancing markets as we call them. In PJM we call them day-ahead Operating Reserve and Balancing Operating Reserve. Those are the large buckets that contain the various categories of uplift, if you will.

Historically in the day-ahead market, uplift has been the result of production cost minimization. So the objective function of the day-ahead market is actually different than the reliability commitment. In day-ahead, the objective function is to minimize total production costs for the entire 24-hour period that is being scheduled.

And so historically the majority of uplift in the day-ahead market has been the result of scheduling resources that were not economic, per se, for all 24 hours of an operating day, what are the most economic resources to carry forward for the peak part of each day, even if they had to be operated uneconomically in the off-peak hours.

We have seen some of the real-time reasons, real-time reliability reasons for uplift that I'm going to get

to, get into the day-ahead market more recently, and I'll get into why that is, as well.

But in the real-time, the vast majority of the reason for uplift that we find in real-time is for the operation of resources in order to maintain the reliability of the transmission system.

And as the other representatives have already discussed, there's really two primary types of constraints for which we operate resources in real-time that will collect uplift.

There's what you typically consider to be your normal transmission constraint, your thermal type constraint, where we have power-flow limits on transmission facilities and we operate resources such that those flow limits on those facilities are not exceeded.

The primary reason for uplift for operating resources in order to manage those types of constraints are the limits in unit flexibility that have already been discussed where once you bring a unit online it either has to be scheduled far enough in advance or you may not get it for the hours that you really need it, or it has to be held online for a certain amount of time after it's on due to those physical issues of actually operating the units.

The other types that again have already been discussed are voltage constraints. Voltage constraints are

somewhat more difficult to model because they must be translated into a thermal constraint in order for the dispatch and pricing algorithms that we use to be able to optimize those resources and actually set locational marginal prices appropriately with those units.

Unit flexibility can also enter into the voltage constraints as well, but it's more primarily that translation of voltage constraints into those thermal-type constraints that leads to the uplift for resources operating for voltage conditions.

This leads me to another sort of reason we've seen in PJM, probably more specifically than maybe the other ISOs and RTOs over the last several years with respect to uplift in our market, and it deals with the fuel transition that Dr. Bowring started to talk about where we've actually started to see some of these coal unit retirements as a result of the economics of the system.

That's actually led to several interesting phenomena. Number one, we don't necessarily operate units just for low-voltage conditions anymore, so they have more units operating in order to support voltage. We've actually seen a fair amount of conditions over the recent years where we have to operate generation in order to control high-voltage conditions.

So we have to bring generation resources online

to absorb reactive power in order to manage a high-voltage condition. We see this on the Bulk Power System as a result of lower transfers across the system, where we see high voltages on the 500 kV system. We've also seen it more locally, where we've seen higher voltage on the lower voltage type systems where we have to run generation in specific areas, which Dr. Bowring referred to in his discussion of the concentration of uplift payments in certain areas of the system.

So in addition to the reactive operations of the units that collect uplift, we've also seen in other areas like blackstart. So certain units on the PJM system that we need to operate in order to secure sufficient blackstart operating on the system--it's a big counter-intuitive--actually have to be online and operating to provide blackstart in what we call "automatic load rejection" or ALR units where they provide blackstart service by virtue of the fact that if we saw a system-wide loss of load, those units can actually keep operating, keep spinning without actually serving any load and can actually assist in restoring the system by virtue of the fact that they continue operating.

These units used to operate as baseload units, and therefore were economic to operate and provide that blackstart service. Again, given the changing economics of the system that we have seen, it has become necessary over

recent years to operate those units uneconomically--in other words, to operate them above cost and compensate them through uplift payments such that the system has sufficient blackstart capability always operating.

Last but not least, I'll just hit on another area that has already been discussed: lost-opportunity cost. So these are units that are following dispatch instructions in real-time either because they are backed down in order to manage a transmission constraint and the hourly integrated nature of the LMP does not result in an hourly integrated LMP that follows the offer of the unit, or in PJM if we actually schedule combustion turbines, so short-term units, in day-ahead that we then do not call on in real-time, but the real-time LMP exceeds that unit's offer, it's eligible for a lost-opportunity cost payment again in order to provide that incentive to follow the dispatch instructions of the operator.

Lost-opportunity costs. We haven't talked at all about ancillary services yet. It's also the place where we see some uplift in the ancillary service markets. Part of that is product substitution cost between energy and ancillary services, but it's a very small number so I'll just mention it very briefly and move on.

Again, in the interest of time, I do agree with what Dr. Bowring said as far as the primary reasons for the

concentration of uplift in the PJM system. Regardless of the reason why we need units to operate, the bottom line is we have certain areas of the system that are chronically experiencing transmission constraints.

And if the resources that are necessary to manage those constraints are inflexible because of their physical operating parameters, they can collect large amounts of uplift, and that is really the primary reason that we see for the concentration of uplift in PJM.

I'll wait until we get on to the solutions panel later today before I start talking about how we have been addressing some of the transparency issues in order to hopefully allow the market to better resolve those issues.

Thank you.

MR. PATTON: Good morning. First of all, I'm David Patton, Potomac Economics. I work with MISO, New York and New England. So I may be commenting on any one or all of those markets.

I think this is a great technical conference. A little secret, for the last 10, 15 years the occurrence of uplift is actually a trigger for the state-of-the-market report recommendations. When we see uplift pop up, it's an indicator to us that there's some dysfunction in the market that I would say probably a third of our state-of-the-market report recommendations target the various drivers of those

uplift costs.

So I've identified five principal drivers, and I'm just going to move through them really quickly, and I'll try to identify which ones result in the concentrated uplift payments. I think you hit some of these in the papers, but not others.

The first, and I think you did mention this, is that when you have reliability requirements that are not reflected in market requirements, then you're naturally going to end up with uplift. Because it puts an onus on operators to take out-of-market actions that sometimes are extremely costly to satisfy the reliability requirements, because the market won't do it by itself. And those costs are, because they're not included in the market requirements, they're not going to be priced and therefore are going to require payments to be made outside the market. Almost the locational variety of those is what leads to the concentrated uplift.

And one thing we've seen in almost every market is that there are areas where RTOs have to manage to a second contingency standard. And generally the reason that is is they look at their system and they say, okay, that's this going to look like after the first contingency happens?

If I don't have gas turbines or something I can bring on quickly in a local area, I'm not going to be able

to respond to the next first contingency within 30 minutes. So I have to precommit my system to satisfy both the first and second contingency.

When you do that, you're essentially establishing an operating reserve in the local area. And if you don't have a local operating reserve product, there's no chance of pricing it and therefore you're going to generate uplift.

You can see with the big increase in uplift in MISO that occurred with the integration of Entergy, most of that--or MISO South--most of that is related to two areas in the MISO South region where we have second contingency requirements. We commit every day to satisfy those requirements, and we generate a sizeable amount of uplift.

So that's an area where, you know, we made a recommendation to think about a local reserve product to address that.

Secondly--and this is a difficult area to tackle even when you are consistent between your reliability requirements and your market requirements, there are a variety of reasons why your market prices may not fully reflect the marginal cost of the actions that you're taking.

The one that you identified is when you have inflexible resources you're relying on, the real-time markets won't naturally allow those units to set price. And

sometimes they're demand-response, which is probably our most inflexible class of resources, if you want to call them resources.

But they can be marginal. The most frequent--the most frequent class that causes problems with most RTOs is gas turbines that tend to be inflexible. So New York probably 12 years ago tackled this problem with their hybrid pricing. MISO is now implementing something very similar that we're going to talk about later today, which is extended LMP, or ELMP. It's pretty much patterned off of what New York did.

But beyond that--and this is the harder part to handle--is the operator going to routinely take actions. While you may be able to price the gas turbines, it's much harder to price the expensive actions that operators take to maintain reliability, particularly as you approach a shortage.

So you may have great shortage pricing, but the operators are tasked with taking actions to prevent shortages. So you don't--many times, you don't actually get to the shortage. And the actions they're taking may be more costly than the shortage pricing itself.

And so when you don't price those, when any of those actions have the effect of lowering prices--and most of them do--you end up generating sizeable amounts of uplift

in those periods.

Now I will say that most of those two causes don't lead to concentrated uplift payments.

Third, a mismatch between dispatch and settlements. And this largely affects those markets which PJM and MISO are good examples, where the dispatch interval is 5 minutes, or 15 minutes, and the settlement is hourly.

And so there you have a class of payments which MISO calls the price volatility make-whole payments; I think PJM called them opportunity-cost payments, where you may for 10 minutes tell a cheap coal unit to ramp down, and then at the end of the hour they're sorry they ramped down because the hourly integrated price was higher than their all-in cost. And that in MISO had caused a lot of our flexible units to operate very inflexibly.

So we create a class of make-whole payments called price-volatility make-whole payments that basically holds them harmless for following our dispatch instructions. It had a big impact on them being flexible, but ultimately if you want to get rid of those--and we really want to get rid of those--is the RTOs should be settling on the same time interval as their dispatch to ensure consistency between the dispatch instruction and prices.

Fourth, shortage pricing not being fully effective. I think I'll defer discussion of that until the

last panel because I think you actually mentioned that.

Lastly, the fifth cause of uplift that is concerning to us is when you see inefficient commitment dispatch, or scheduling decisions made either by a RTO or by market participants. One of the truly systemic causes of uplift is poor scheduling between the RTOs.

What you see in high load periods is that when prices fluctuate in two adjacent RTOs and participants respond to it, what will happen is the RTO operators can't rely on what's going to be coming across the interface. So they'll commit units. And then if prices happen to be high for 10, 15 minutes, they'll get a flood of imports from their neighbor, and all those commitments then end up looking uneconomic and get paid huge amounts of uplift.

Again, it doesn't lead to concentrated uplift payments, but it is an issue that just creates uplift on a continuing basis. So there are issues, or there are initiatives underway to help bring much greater coordination between the interchange between the RTOs. And when that coordination occurs, the operators can rely on it more--can rely on efficient schedules occurring, and can be slower to commit resources and therefore generate less uplift.

The other class of inefficient commitment in dispatch that I would mention--and some of the RTOs have addressed this--is real-time commitment of resources.

Because the dispatch software runs on a 5-minute basis, or a 15-minute basis, depending on the RTO, and is just making a dispatch decision, then you have to ask yourself, well, how do you make the commitment decisions? Because units that you're committing in real-time are the ones that are getting paid all the uplift.

So those RTOs that have implemented economic models to guide the commitment of turbines, largely peaking resources, have made great strides in reducing uplift. And if you want to see an example of that, look at the uplift in New York before and after they implemented their real-time commitment software. MISO calls it "The Look-Ahead Commitment Software."

So the better that software operates, and the more that the operators adhere to it, the lower your uplift is going to be because it lowers uneconomic decisions that are being made in real-time.

MR. SAUER: And just so I understand that, it sounds like what you're ultimately saying is prior to that software, you might have a resource that's say dispatched for, or an operator wants to say dispatch it for a couple real-time intervals because it will be economic for that point in time in the near term? And this model enhancement that you're talking about will essentially assess the minimum run time of units and help predict whether it will

be economic for that entire time?

MR. PATTON: Correct. So, yeah, there are two decisions that they're making, and both of them are equally important. And that is, when do I turn it on? And when do I turn it off?

And those two decisions largely are economic, but if you don't have the sort of model then often what you have is operators relying on rules of thumb that can lead to much less efficient decisions being made. And the less efficient those decisions are, the more uplift you're going to have to pay those resources.

MR. DILLON: Good morning. Thank you for inviting me. I'm Richard Dillon with the Southwest Power Pool, and I'm in a unique position here.

The unique position is that the environment for Southwest Power Pool is all regulated. There is no retail open access in that environment. And that causes some tweaks in the way we operate.

Having said that, we operate at a real-time balancing market for seven years, and the majority of the uplift during that time was related to congestion rights. Now that is carried forward as in all the markets. Congestion rights are always a fun topic, but operationally all of a sudden when we brought in the day-ahead market, which was about unit commitments, centralized unit

commitment, the uplifts magnified.

And the majority of the magnification came from really two specific areas. One is what we call headroom, which is committing resources above and beyond what you expect to need because of risk avoidance. And there are several factors of that that I'll go into in a second.

The other one is related to local reliability, that there are items out there that quite frankly the RTO cannot see that we rely upon the local operators to identify, or they can't be modeled in the dispatch engines and still pursue.

As in anything else, this industry has been evolving over time. Some of the items that have been mentioned are as a result of the evolution, such as what Dr. Patton just mentioned is that we tend to in the industry schedule interbalancing authority, or Inter-RTO, on an hourly basis. ramping from 5 minutes before till 5 minutes after. And then you throw on-peak and off-peak into that economic equation and what you have is the entire interconnects are scrambling at, in Central Time, 5 minutes till 7:00 a.m. till 5 minutes after, and then 5 minutes till 11:00 p.m. until 5 minutes after, really playing hot potato between the RTOs.

Because the load still is what the load is. We're just readjusting the entire interconnection for those

balances. That's an item of evolution. We have not yet moved beyond the 5-minute.

Now part of what Southwest Power Pool implemented in March was that there was 5-minute settlement. And the 5-minute settlement means that for those schedules you will end up seeing higher prices. And hopefully that will incent trying to move off of everybody playing hot potato at the top of the hours.

Now I deviated from the headroom topic. Headroom, or committing excess capacity, we tend to see that because of uncertainty with the load or the resource forecasts. And you will have that, especially in the day-ahead market because forecasting next-day is very difficult, especially when you throw in the renewables on top of that.

And in Southwest Power Pool, our renewable is about 9 gigawatts out of a 46 gigawatt load. So it is a very substantial amount of renewables that everyone tries--as a matter of fact, the day we started up we had a call from the renewable forecasting entities saying because the cold front is coming through, the actual output will be somewhere between zero and what we sent you.

(Laughter.)

MR. DILLON: Needless to say, in our terminology of headroom, we had to commit sufficient capacity to presume that there would be nothing on in regards to renewable the

next day. So we have that item.

Another item that was mentioned tangentially is the ramping needs. Both the top-of-the-hour and also as generation moves on and off, you have two different types of ramping needs going on.

One is to make sure we have sufficient ramp, and that is the top-of-the-hour type situations, or if you have significant industrial load coming on and off.

The other one is the fact that essentially you have two different styles generators, very fast movers and very slow movers. You can almost think along the terms of you've got some semi-trucks and you've got some sports cars. And when you have to get something, get the load delivered, if the semi can't get there fast enough you offload and run it up with the sports car, and then bring them back as the semi moves up.

And that results in uplift, also, because you have peaks and valleys going on that impacts both of them equally. So we have ramping, again an item of evolution, because the ramping design in this industry was for 10 minutes. The market is a 5-minute market.

So the standards were set up: Can you get there in 10 minutes? But we're dispatching every 5 minutes. Another item that has not yet aligned in the industry, and that causes price fluctuations that result in uplift

payments to generators to make sure that they are kept whole in their costs.

One other item that I will mention and then hand it back in the interest of time is run constraints are already there. That you can only run generators for so long before you have to do maintenance. And if you really run them up and bring them back, then the maintenance goes up.

Well there's also the emissions. The emissions have been out there, and the emission, as we know, will continue to be out there; that a generator can only be used so many times before they start hitting their emissions constraints.

At the moment, even though we are all struggling with it, there is not a perfect solution for how do you balance the equation. When the air conditioner doesn't come in in the summer, it doesn't matter what the standards were; my air conditioner is not on. And we have yet to come up with a balance of all these externalities that exist.

With that, I will conclude.

MR. SAUER: Well thank you very much, everybody. I know that was--as a couple of you pointed out, it was a longer answer session, and I'm sure it'll be longer in the other answers here, but in my mind it's the most important thing for us to do is to understand the drivers before we can move forward. So we appreciate the length of that

discussion and everybody sharing their knowledge there.

One thing Stu pointed out was how the voltage constraints can be modeled by modeling them as a thermal constraint, essentially. One thing we'd like to hear a little bit more about is kind of along the lines of where Stu was going there, which is what are the challenges of modeling some of the constraints that were pointed out as being the main drivers for concentration?

And whoever wants to start, go for it.

MR. BRESLER: Well since I started it, well I'll go ahead and start if that's okay, what we do at PJM.

MR. SAUER: Okay.

MR. BRESLER: Starting with the voltage constraints, for what we typically think of as a voltage constraint, where again we need to operate resources in order to support voltage--so to keep voltage higher, in other words, up at an acceptable level.

PJM, and I know all system operators probably, have been operating for constraints that are translations from reactive or voltage constraints into thermal constraints. In PJM, we typically call them our "transfer interface constraints." And they are sort of wide-area, multi-element 500 kV type constraints where for the loss of a 500 kV transmission line you can see a significant voltage drop in other areas of the system.

And so, you know, since well before I started at PJM we have been translating those voltage-drop type of constraints into interface thermal constraints, where we monitor the flow on a collection of transmission lines and ensure that the flow on that collection of transmission lines does not exceed a level at which that post-contingency voltage drop does not become unacceptable. Because when it hits the unacceptable level, it can lead to voltage collapse, as we've actually seen historically.

The more difficult ones are the ones that I think are somewhat more localized. So we see typically actual low-voltage conditions in certain smaller areas of the system, and there's a very small subset of generation that can actually be operated to resolve that low-voltage condition.

Unless we pick sort of, again, a kind of a cut set of lines, if you will, on which we can monitor flow versus a flow limit, it can't get into the price.

And so, absent that translation into that thermal limit, the unit that needs to operate is really going to have to be paid uplift in order to make his cost back because it's not going to be in the LMP.

Again, the harder one that we've seen more recently is when we have to operate units to control high-voltage conditions. Because we have a way to come up

with a way to model that thermally, that there doesn't seem to be a straight-forward mechanism for modeling a thermal flow, if you will, that can say, you know, below that thermal flow I can turn the unit off; if you're a little bit above it I need to turn it on. It just sort of doesn't work that way.

So that one is still challenging, and we haven't come up with a solution for that one yet.

MR. PIKE: If I can continue on--

MR. SAUER: Yes, please.

MR. PIKE: --so a couple of challenges, and Stu highlighted the voltage constraints very well. New York has a central-leased voltage constraint. It's a voltage-collapse constraint, and forever we've managed it through a translation into a thermal limit on the constraint and solved that constraint with a marginal-cost dispatch that keeps flows below a targeted level.

But the challenge really becomes more in the load pockets and the very tightly constrained areas where a lot of times we're committing for a second contingency voltage support event and trying to model that as a second contingency event in the system that would translate into a marginal energy dispatch constraint and set price is a challenge.

I think it also kind of leads us to a secondary

question, which would be: Is LBMP the right price signal to send to correct the underlying condition? Is it another resource that you need? Or is it another reactive resource that you need? And if it's truly just a reactive support condition, LBMP might not be the best choice of a price signalling mechanism.

The other challenge that we face is we have a loss-of-gas obligation in New York City and Long Island that's driven by the New York State Reliability Council, which essentially says for the loss-of-gas pressure in the system you have to have enough resources running on an alternate fuel that they can maintain synchronization to the grid and then ramp back up on the alternate fuel.

So again it's not a megawatt dispatch obligation; it's a commitment decision to have a certain subset of resources online in the city and in Long Island at various load levels. So it's not a dispatch constraint, it's a dual=fuel obligation and resource.

Now we have seen over time that some of the newer units that are coming into these locations have fuel swapping capabilities. So they can detect the loss of gas and automatically switch to an alternate fuel. And we're trying to leverage those types of resources to provide these services because it's essentially a zero-cost solution after the capability has been built on the resource and you're not

incurring any additional cost on that resource until the actual contingency event happens and they burn into the alternate fuels.

But, you know, that's a changeover in the fleet before you can truly be able to address that completely with those types of resources.

MR. SAUER: And pardon my ignorance here. I guess I'm curious to understand whether that constraint, the loss-of-gas constraint, is in the market, or priced as part of the day-ahead or real-time market? And if not, what are the challenges associated with incorporating that constraint?

MR. PIKE: It isn't today. It's done through a commitment decision from the local operator at various load levels at the prescribed out-of-time. It can be a selection of units. So it's usually typically like one-of-three units, or two-of-five units.

We do incorporate that into the optimization, so we are looking for the lowest production-cost resources to meet that constraint. But it's just a commitment decision. It doesn't demand a megawatt dispatch; it just commands a commitment of the resource.

So to think of that in the real-time market when the unit is running, it's fine to be running on a blend of oil and gas and dispatching along that cost curve, the idea

being if we have a gas contingency and we lose gas supply, the unit will ramp back but it will still be burning an oil-based fuel to keep the unit online, and then it can ramp itself back up after it's stabilized on the alternate fuel.

So there's no "dispatch." There's no incremental megawatt condition off of this type of resource. It's a be-online and be burning this alternate fuel for your minimum generation levels.

MR. SAUER: I think Joe and David were at the same time, so--

MR. BOWRING: Go ahead.

MR. PATTON: I was just going to jump in real quick on the gas contingency question. Clearly historically planning and commitment and dispatch have all been focused on electric system contingencies, and I think increasingly gas system contingencies have been something that RTOs have worried about, not only contingencies but also just your garden variety market phenomenon in the gas market, and availability of gas where some generators might not be able to get gas on the day you really want them to have it--not because there's a contingency but maybe just because gas is scarce.

But I think it is something that, you know, we've certainly talked about as a potential market design improvement as explicitly recognizing gas system conditions,

or gas system contingencies in the creation of ancillary service products.

For instance, you could imagine an operating reserve product that was a non-gas operating reserve, which is effectively what New York needs. Right now, most of these concerns are being addressed by those RTOs that are most concerned about them. Most of them are being addressed by manual actions taken by operators to position the system to reduce its reliance on gas. But you could certainly imagine market requirements that would reflect those. It's just not something that I think any RTO has really done the research on to figure out how you would specify such a product, and when would--you probably don't need such a product to be utilized 8,760 hours; you'd probably just need it under certain conditions.

MR. BOWRING: So just to comment briefly on something that Stu and Rob both said, some reactive constraints you can model thermally and capture in the price appropriately, and some you can't. And it's important not to try to do it in the latter case because you can have unintended consequences.

And then secondly on the gallon-of-gas matter, it's also important not to concede too much to the limitations on the gas system. That is, not to permit uplift for example for--and require 24-hour notification

periods, or long run times simply because of limitations on the gas which result from economic decisions about what kind of gas service to take.

You need the right set of incentives in the capacity market and the energy market to make sure that you're not paying uplift inappropriately there.

MR. SAUER: Any other perspectives that need to be captured?

MR. ALDERETE: I will just add that, as the other ISOs stated, in some cases you may be able to translate in the voltage constraints related to the thermal limits, there are cases where you simply cannot do it. Specifically for the California ISO, as I mentioned earlier, in cases where we don't have that option what we do is to impose market constraint, a commitment constraint, basically to ensure that we have enough resources in that area to be online for the time that they are committed.

Again, the drawback is that this is a market constraint but it's a constraint reflecting the LMPs.

MR. SAUER: Switching directions a little bit, we've heard from all of you especially about some reasons behind some of the drivers for concentrated payments. One thing we'd like to explore a little bit further is whether some of the reliability needs driving uplift payments are incorporated into say transmission planning purposes, or how

those reliability needs are used to assess grid reliability decisions.

Richard?

MR. DILLON: I eventually remembered [referring to the name tent].

So again you end up with reliability needs that are incorporated in the transmission planning process. A lot of what we talked about can be included. Voltage is a little bit more difficult. Over-voltage is real difficult to include because you don't know when it's going to hit, or a lot of times what's causing it.

But a lot of the items that we talked about, the uncertainty resulting in commitments out there, are not a transmission issue. They're an uncertainty with trying to make sure that the reliability of the real energy stays up. And that really can't be captured in transmission planning.

We could have the best transmission grid out there, and we still with the uncertainty of load and other things going on in the system, would end up having commitments that you may have a generator sitting on minimum which automatically means, assuming the pricing is right, that they're going to get a make-whole payment because they're sitting on minimum.

Every generator that we have sitting on minimum, whether it be for voltage or just to make sure we have the

ramping capability, et cetera, you can almost consider that that is automatic uplift. And those--the uncertainty is after we get our transmission grid to a nice level, the uncertainty is actually the major driver.

MR. BRESLER: Thanks, Will. From PJM's perspective and the regional transmission expansion planning process, largely areas of the system that are chronically constrained we do see transmission upgrades being triggered either for the reliability trigger which is the most common; we have seen a couple of market efficiency upgrades result in the process as well because of the economic effects of transmission constraints.

But more recently, given the uplift we have seen in the PJM market, we have another category in our RTEP planning process which is called "Operational Performance." And we are looking to see whether or not we can find upgrades that will be beneficial for the system that consider a lot of these uplift payments that we have seen in the market. Because uplift is another signal, even if it's not through LMP and the congestion dollars, it's another signal that the system is chronically constrained in certain areas.

We have seen planning upgrades go into the system over the last couple of years in the form of reactive devices--static VAR compensators and those types of

things--which have resolved some of the voltage issues I described in my earlier comments. But we are looking to incorporate these uplift payments, especially where they are significant and where they are concentrated into developing additional upgrades in the system, as well, that might be able to resolve those issues.

MR. SAUER: Just a quick thought there. So that transmission performance look, essentially does it try to weigh the economic benefit associated with the uplift credits that have been paid out, or may be paid out for the future, versus the cost of the transmission--

MR. BRESLER: Yeah, there isn't a direct cost/benefit threshold like there is for an economic project where I think it has to be--the benefits have to be 1.25 the cost, I think. There isn't a bright-line test like that.

But the thought process is that uplifts again can be signals of the need to operate out-of-market resources in order to solve, you know, transmission congestion issues which can be a signal that there is operational performance issues going on that could trigger transmission upgrades. So we're looking at that as potential driver in the future, yes.

MR. BOWRING: So I mean I agree with what Stu said, but it's also the case that RTEP transmission planning can be a way to address persistent, long-term concentration

of uplift payments. And I don't think it's being done adequately now. As Stu has indicated, PJM is moving in that direction. I think that makes sense, and probably even a more formal indicator. Again, it's not going to solve, as Richard said, it's not going to solve all uplift problems but it can address these persistent concentration issues at times when there is at least a potential transmission solution.

MR. PIKE: One success story I can relay. We had a problem in our north country transmission limitation that was requiring us to really extensively run a unit up in that region to be able to deal with support on a post-contingency basis.

It wasn't a formal process, but through an informal process working very closely with the Public Service Commission and the local transmission owner we were able to go through the uplift costs that were being generated to keep this unit running, and ultimately build out the transmission system to be able to address that and avoid that going forward.

So it's not a formal process, but we do an active communication with the New York State Public Service Commission of the uplift costs that are being incurred for local reliability needs, what the source of those are, so hopefully we can take up initiatives aimed at reinforcing

the transmission system.

MR. PATTON: I think in general we see the sorts of constraints that are generating the uplift included in the planning process. I think one of the problems that we see, though, is that most of the models that would be used to calculate the benefits of resolving a transmission constraint may not fully reflect the true benefits in operations.

So, for example, those models may simulate what the dispatch costs are for handling a certain constraint, but in real-time what some of these drivers cause is for example if I'm in a load pocket committing peaking resources that aren't setting prices, and that real-time price signal is not getting sent back to the day-ahead, and so you're not going to schedule as much energy in that area, so you're not going to get as efficient a commitment coming out of the day-ahead as you would predict in your transmission planning model. So you'll be generating more cost than your planning model may indicate that you're generating.

So I think most of the time I would say I don't think the planning models are missing constraints that are generating uplift, but they may not be fully accounting for some of these drivers.

MR. BRANDIEN: I agree with most of what everything that's been said here, but from an operator's

perspective a lot of times we have to make a decision this afternoon for tomorrow based on the flexibility or inflexibility of the resources.

So when we get into real-time, Dr. Patton spoke about efficient use of the ties, letting the ties swing in when the price signal is there, that's great when we get into real-time and we benefit from that. But the decision I made yesterday afternoon because I had to get that resource rolling and get it online to ensure reliability, I can't sit back and say I hope the ties are going to swing in to me. I need an operating plan that meets the NERC Reliability Criteria to operate through the day, and it really goes back to the flexibility or inflexibility of the resources that you have to make your decision on.

And once you've got those units rolling, the uplift is coming.

MR. SAUER: One item that hasn't come up in discussions yet which we'd like to hear more about, certainly from some of the RTOs, it appears that some of the uplift may be generated by commitments that aren't made by the RTOs themselves but may be made by say the transmission owner.

How common is this practice across the RTOs? And what implications does that have on the ability to decrease uplift payments?

MR. RAMEY: A situation like that occurs in MISO often during high load conditions. And it's generally associated with the self-deployment of load management type resources that our asset owners or LSEs may have.

So in the control room, as Pete mentioned, even inter-day, we're making a commitment plan to cover expected requirements three, four hours out, six, eight, ten hours out within that same day.

It may look like a load forecast error when you get to the peak period and the load hasn't manifested quite like it was forecast to be, commitments decisions were made, prices are depressed as a result, which can lead to pretty significant uplift payments for those hours.

At least within MISO, we don't have currently good process procedures where we're getting information from our LSEs that have some of these load management capabilities. So sometimes in those high-load days you're already into higher priced fuel resources. You can make pretty significant commitments to try and cover those requirements that don't materialize, and that can lead to daily pretty high spikes and uplift payment requirements.

MR. SAUER: Stu?

MR. BRESLER: Yeah, I think from PJM's perspective I don't think we've identified sort of self-scheduling of generation resources within the RTO as a

significant source of uplift.

To Todd's point, I think where market participant action probably hits us more significantly is actually in an area that Dr. Patton brought up earlier, which is the volatility of interchange.

I think that hits us particularly hard on the peak days that Todd was talking about. So when we see conditions where prices begin to really rise on days where the system conditions tend to get stressed, we can see significant amounts of interchange. So, you know, energy imports, depending on your perspective, but from PJM's perspective imports into PJM that can cause the commitments that the operators made as recently as an hour or two before suddenly become uneconomic.

And the market really sort of kind of suffers a double whammy there, if you will, because the interchange gets paid the LMP at the interface where the energy comes into PJM, but the market still has to pay the bid production cost guaranteeing the resources that were previously committed. So you're sort of paying twice, if you will, for the same energy.

So we have been working, as Dr. Patton said, on efforts to better coordinate interchange with our neighbors, recognizing not all of our neighbors are ISO/RTO markets. So we're certainly doing everything we can there, but we

also are searching through our stakeholder process says to better manage interchange in particular on those days where we really hit peak system conditions where again we can really hit sort of the hardest, if you will.

I think from the perspective of the issue Todd brought up about sort of load management on peak days, I think from PJM's perspective I think that's some of the advantage we've seen of the fact that a lot of the load management in PJM's system actually comes through the market, is i think we have a lot better knowledge of what's happening with load management on those peak days than we otherwise would.

MR. PIKE: I'd offer, we don't see local reliability commitments being driven frequently in the Upstate regions. Frequency is really driven by peak load conditions, and more importantly maintenance conditions. And this is where a local transmission owner will see, because of some maintenance work they're doing on their lower kV system, they may need a specific unit.

So it's not a significant contributor to uplift in the Upstate region, but certainly something that we do acknowledge that those units need to be run at times.

MR. SAUER: Just very quickly--I'm sorry.

MR. QUINN: Just a quick follow-up. You said there's not a big issue in the Upstate. Is it a big--it is

a big issue in Long Island and New York City, kind of a local PO kind of commitment of resources?

MR. PIKE: In New York City and Long Island, there is a lot more from that, but it's not generally transmission related. It will be second-contingency preparations, voltage preparations, loss-of-gas preparations. So rather than a specific thermal limit that will be driving it on a lower kV system, in those regions it's more the other types of voltage commitment type constraint.

MR. SAUER: Joe.

MR. BOWRING: So just very quickly, a couple of folks mentioned demand response. So it's important to remember that all demand response payments in the energy market are uplift. And that's one of the things that wasn't mentioned as a driver, typically not sometimes even included in the total uplift calculations but it is important to remember that.

MR. ALDERETE: Well from the California perspective, I would say that one of the other factors that we have to consider is the fact of not just a flexibility of the units physically speaking, but also the practices for coming to the market.

One of those is setting scheduling. Once units are coming and we set the schedules, your room to maneuver

the system is reduced.

As you know, California ISO is an importer, either internal imports, resources coming we set the scales, usually pose a challenge in terms of how much room you have to maneuver.

MR. SAUER: We've got about 20 minutes left, so let's switch to the, kind of the last observation from the finding, or from the paper that we pointed out, which would be, we saw relationships between day-ahead and real-time price differences in uplift, and also energy prices for that matter.

I'd like to spend some time focusing on the day-ahead/real-time price divergences in particular and hear about how actions--how actions impacting supply in one market may impact say prices and uplift in another.

And I'll just turn it back.

MR. BRESLER: I'll just go ahead and start out a little bit with the PJM experience there with respect to day-ahead versus real-time.

I mentioned through my initial comments some of the phenomenon we saw with operating units for blackstart and reactive for the purposes of making sure we could maintain real-time reliability.

Over time, as those commitments increased, those commitments were being made only in the real-time market, we

began to see an increasing sort of systemic mismatch between day-ahead and real-time. Because the resources that were being utilized to maintain power balance in real-time were different than, I would say in some case significantly different, than the resources that were being scheduled as part of the day-ahead market.

So we began an effort a couple of years ago now to make sure that when we knew that we had to make those commitments in real-time we reflected them in day-ahead as well and made those commitments in day-ahead. It did have the effect of increasing uplift in the day-ahead market, because by definition those resources weren't economic or they would have been committed economically day-ahead, but it did decrease that mismatch between day-ahead and real-time which decreased the balancing uplift that was being paid, and also in particular decreased the category that I referred to as lost-opportunity costs.

Because what we saw was, in day-ahead we saw fairly systemically commitments of combustion turbines, UTs in day-ahead, that were then not necessary to operate in real-time because we had the extra injection of energy from those additional reliability commitments in real-time.

And so once we started sort of aligning day-ahead and real-time better by reflecting those reliability commitments in day-ahead, the LSE payments reduced

significantly because we didn't have that mismatch of scheduling the CTs in day-ahead and then not needing to run them in real-time.

So one example from PJM's experience of how, recognizing what's necessary for reliability in day-ahead can better align those two markets with better results, both in pricing as well as uplift.

MR. DILLON: So we've had an interesting startup, and I don't know to what extent this is indicative of other areas, but one thing that pops up that totally is aside all the discussion about virtuals, et cetera, is the schedule differences, the inter-RTO schedule differences between day-ahead and real-time. And in our case they're actually swinging signs that in the day-ahead they will be shown as a net import, and in real-time net export, or vice versa.

And that in itself results in a commitment change that really hits the real-time--not even the day-ahead reliability unit commitment, it also increases the risk. Remember I keep going back to the uncertainty. Because you are not sure as to what wholesale transactions will be moving across the interface, a lot of those come in closer to real-time than in any day-ahead activity. And the day-ahead activity is more of a hedging activity, a pure market activity.

Those swings create a lot of disconnect between

the day-ahead and real-time prices. And they're hard from an operational standpoint; they're hard from a virtual standpoint to guess what's going to happen. And so that's one item that we have noted swinging our prices between day-ahead and real-time and the commitment activity.

MR. PATTON: So I think there are a couple of different things going on. The way you did your correlation we I think you looked at monthly uplift against average hourly differences by month.

And what you'll tend to get when you do the analysis that way is the months with highly volatile real-time prices will pop up in that sort of analysis as being problem months.

You could have perfect correlation in those months; it's just that if--in other words, the day-ahead market is producing an expected value of the real-time price, but if you're in a high load period where the real-time price is going like this (indicating), that sort of month is going to look terrible.

Now we generate a ton of our uplift in those periods because those highly volatile real-time months are months where load is really high and a couple of these drivers really manifest themselves. One is the inefficient interchange, which I think we've talked about a bunch; but secondly is the operator actions to respond to potential

shortages start to play a really big role.

You know, most of the RTOs now I think have pretty good shortage pricing. We designate what different classes of reserves cost. And when we're actually short, we'll set appropriately high prices.

The problem with that is that the operators aren't constrained by those values. If the operators forecast a shortage in an important class of reserves, the fact that that class of reserves says it has a value of X in committing these unit costs five times that won't stop them from committing that unit will prevent the shortage and will result in a ton of uplift.

So I think some of that correlation may be related to the inability to price a lot of those very expensive actions that are taken.

But as far as day-ahead and real-time prices go, I think the biggest sustained driver of uplift is the underpricing of real-time energy by not allowing the high-cost inflexible units that are effectively marginal a lot of the time to set price, and we make them marginal more when we don't allow them to set the price. Because, again, it's the feedback to the day-ahead.

If I'm running--you know, it's interesting. We did this study of the benefits of RTO markets prior to the start up of MISO, and then when MISO actually started the

benefits seemed lower and we were trying to figure out why. And the reason why was we were running peakers a lot more than what we predicted.

And part of the problem there was, when we ran peakers and they didn't set price, it didn't motivate anyone to schedule more so that we could schedule something other than a peaker in the day-ahead market.

So if you don't solve that problem, then you'll have a sustained disconnect between your day-ahead and real-time that can only be resolved by allocating that uplift to deviations in the day-ahead, forcing the day-ahead price to be higher than the real-time price to account for the fact that the real-time price is effectively depressed.

And that allocation problem I know is something that has taken up a lot of the Commission's attention over the last six or seven years, and I think it's still not fully resolved in most of the RTO.

MR. BOWRING: So just to pick up a little bit on what David was saying, I think it's important to look beneath the surface of the correlation.

So when you see a relationship between, the difference between day-ahead and real-time and uplift, just take January in PJM. There were lots of moving parts there. You probably saw a significant difference between day-ahead and real-time, but it was--the underlying cause for the

uplift was primarily conservative operations in response to disproportionately high outage rates early in the month.

So what was nice about--one of the nice things about the study was it was trying to look across all the RTOs and look for common features, and that's what the correlation shows. But as you know, that's the first step in the analysis on things like this.

And what I would suggest is drilling down one step further. But in addition, there are issues in for example the lost=opportunity cost payments where the calculation in PJM is simply being done incorrectly algebraically. The opportunity cost assumes that there's no startup and no load cost and imputes that to profit, where in fact of course it wouldn't actually be in that revenue in the lost-opportunity cost.

So I mean that's a nontrivial contributor. It's obviously not the source of the issue, but it's a nontrivial contributor.

MR. SAUER: Any other thoughts on that, real quick?

(No response.)

MR. SAUER: Certainly we've heard a lot of discussion on the interchange and how different expectations or uncertainties about interchange can impact uplift.

I think we heard in particular from, certainly

from Richard, and I think we heard from Stu as well about it. Is this a common theme for a lot of the RTOs, or how is it impacting one RTO more than others?

MR. BRANDIEN: I'll jump in as New England.

We see it as an issue particularly in the wintertime. We receive a lot of energy from Quebec. If you take a look at Quebec's load profile, they have a large peak. They're pretty much all-electric. A very large peak in the morning. I believe they're morning peaking, and it really dies down through the daylight hours, and then they get a large evening peak almost to what the morning peak was. So it's really, you know, the shape of an "M" or a camel hump.

So we see the interchange disappear in the morning load pickup, and we get energy during the afternoon hours where we have the resources to supply, because our load ramps up during the light time hours, and then a large jump in the evening hours. And we're not sure what that interchange is going to be at two, three o'clock in the afternoon, and we know it when we get there.

So there's a lot of uncertainty around that. At the same time, we can see the New York/New England interface swinging to us because our prices tend to be higher than anybody else in the Eastern Interconnection.

The other thing that we have to wrestle with is

how the combined cycle gas units can run. Is the pipelines gonna put 'em on a 1/24th take? And we lose the flexibility very similar to California where they almost look like a self-schedule and we lose our flexibility to be able to redispatch the system.

We have to take a lot of that into account. We have to put a good operating plan in place to deal with those uncertainties, and you see it result in, at times we hit it out of the park and we're exactly right; if we guess wrong, we can incur a lot of uplift. But we need to make decisions to ensure the reliability of the system.

MR. PATTON: Okay, so one reason I brought this up initially was this is one of my favorite recommendations. We first made this in 2003 and have faced the red herring argument for--you'd think I could have overcome this in more than a decade with some thought--

(Laughter.)

MR. PATTON: --but the red herring argument that to solve this RTOs have to get involved in the market in a way that is inappropriate in some fashion.

And that argument sounds really good, because what we first said is the RTOs ought to coordinate the interchange so that the power is worth more in New York than in New England, and they ought to be adjusting the interchange to New York.

And participants said, hey, wait a minute. We schedule power and you're effectively asking the RTOs to engage in a market transaction in competition with us. So that argument seemed to have some sway.

Where we're moving now, and I think the Commission has seen this, is allowing participants to put in basically spread offers that say if the spread between what the RTOs forecast in this market versus that market is greater than X, then schedule my transaction.

So that achieves the same sort of coordination between the two. But importantly what it allows the RTOs to do is have some ability to rely on these massively valuable interfaces.

I mean, the ability to move 2 or 3 gigawatts from one area to the other is, from a reliability perspective is enormously powerful. But what you're hearing from New England--and I don't think they're doing anything wrong--is they have no idea what's going to be happening, so they can't rely on it.

They've got this really valuable interface with New York. If they knew there were offers sitting there that could be struck if some unit went out in New England, or power was valuable in New England, they wouldn't have to start up their very costly oil resource that you have to make a decision on six hours ahead of time, or whatever, is

definitely a big driver, probably bigger for ISO-New England because they don't have as much quick-start resources so they can't wait as long to make decisions as some of the others.

But probably the most dysfunction occurs on the PJM-MISO interface just because it's massive and it's very flexibly scheduled. Every 15 minutes it can change by large quantities. And so when you see any sort of price spike on one side or the other, you just get these potentially large swings in power that are not coordinated and they can be very inefficient and lead to massive amounts of uplifts during the real tight days.

So I think it's an enormously important issue. There's almost nothing that will produce more production cost savings than scheduling interfaces efficiently between the RTOs, in my opinion.

MR. SAUER: Todd, and then Bob.

MR. RAMEY: Yeah, thanks. Most of my comments were covered by Dr. Patton, but as he said for MISO during high load conditions this is a big deal. When prices are volatile, naturally just because you're up in the part of your supply curve where plus or minus 2 to 500 megawatts of total requirement can take you from a $200 marginal resource up to a $500 or $700 marginal resource.

So you've got natural high levels of interval-

level price volatility combined with the current scheduling practice of market participants reacting to price differences.

As Dr. Patton was saying, the problem with the situation today is that we can produce, MISO can be printing at $200 price for one interval, PJM may be at $500 higher than that. Market participants see that. What they don't know, they know that there's a price difference; power needs to move from MISO to PJM in that circumstance. But what they don't know is if it's 1,000 megawatts that'll bring the prices together, or whether it's 200 megawatts, or whether it's 5,000 megawatts.

So invariably the net of the market participants' reaction is they're going to get the volume wrong. They just don't have the information.

So in those tight operating conditions, the way that interface is scheduled today, you can get very volatile interchange as a result and, you know, plus or minus 500 or 1,000 megawatts of interchange can have a dramatic impact on the pricing outcome of both MISO and PJM.

MR. PIKE: I can't resist the opportunity to just put the plug in that PJM and New York will throw the switch on coordinated transaction scheduling in two months' time.

So, absolutely critical. Certainly something that's very important is understanding where transactions

are going to go to manage your fleet of resources.

Getting the prices right at the borders is really the key to that. The transactions will follow the price, so you have to make sure you can get that price correct and get the opportunities to get scheduled so the power can flow.

MR. SAUER: I think Guillermo then Stu.

MR. ALDERETE: From the California ISO's perspective, I would just say that we're an importer. The balancing authorities are not market-based. And we don't have the price base and interchange, but rather what we expect to happen in the real-time is, one, we already cleared the day-ahead market, and usually that happens in the summer or spring time, is that we have to deal with unscheduled flows because there are transactions outside our system that simply has to come through, partially through our system.

So that shows up only in the real-time. So we have just simply to meet that, and that puts a challenge for the real-time operations because there is no projection of how that is going to show up.

MR. BRESLER: Thanks. I just wanted to make a real quick comment, first of all seconding the advertisement from Rob on CTS.

And by the way, Chairman LaFleur, as a result of CTS, most primarily we now have a common acronym, CTS.

(Laughter.)

MR. BRESLER: But also, in sort of Dr. Patton's defense, I don't think the argument was that much of a red herring as far as the ISOs/RTOs getting into making, sort of becoming market participants, if you will. So I hope he doesn't feel like he spent a decade not being able to get over the hump that wasn't really an argument.

I do think CTS is a significant step forward with respect to that. But it's also important to recognize that we're not taking away market participants' ability to schedule interchange on their own.

So the sort of spread bid, if you want to call them that, between the ISOs/RTOs, you know, are not going to be the only way interchange gets scheduled. So I think we do still have the potential for significant swings of interchange on the basis of market participant schedules in the future.

There may be more that we can do, is what I'm getting at, to make sure that interchange is scheduled efficiently with respect to between the RTOs. That's all I was trying to get at.

MR. SAUER: And that takes us to just right about 10:45. So--unless there are--oh, pardon me.

CHAIRMAN LaFLEUR: I just wanted to say that I got as much from listening to your questions as anything I

could ask.

While we have the ISOs up here, I'm interested in how you see the forward trajectory of these issues. You all have various resource-mix changes happening, sometimes quite acutely. Do you think that will exacerbate some of the things you talked about? Do you think there are things happening that might alleviate some of the issues?

I know that's a big question, but I'm interested if, before we get the market participants up, how you see this evolving.

MR. BRESLER: I'll go first again. I think it's an extremely interesting question. I think from PJM's perspective I can see, absent any further changes, I can see the issue is probably being further exacerbated, if you will.

Gas/electric coordination is one thing that we really need to work on if we're going to make progress with these issues. Again, as the fuel mix continues to evolve.

And I think as ISO-New England has done, as PJM has now proposed to do, changing some of our capacity market rules in order to make sure that we adequately compensate resources for the flexibility that we need in order to operate the system not only reliably and making sure we have the resources we need to maintain reliability, but also efficiently, will also be an extremely important step

forward to keeping as much of the system operation in the transparent prices--which is really all of our goals--to ensure that going forward we incent the necessary investment and minimizing that which comes in through uplift which does not have the transparency and the stimulus for investment that we really need.

So I think these changes that we're working on are very important in that regard.

MR. PIKE: I don't think these problems are going to go away without us actively addressing them. I think we're seeing a fleet changeover, and miraculously when the fleet changes over we find local reliability rules that we never knew existed.

So I think we need to do some very active looking at that to make sure we're not surprised by those findings, that we can address them proactively so resources can retire, if that's the appropriate action for them to take, and we can get new resources in that do have some of these advanced flexibilitas and capabilities that we're looking for.

MR. BOWRING: So just to--I would agree with Stu that there are a number of things that need to be done in PJM in particular, and that there are actions in those directions at the moment.

It's not going to solve itself. The problems are

not going to go away. At the same time, it's important to remember that there always will be uplift. We're not going to get rid of uplift. But there are some drivers that have been talked about that can be addressed, and some levels of that uplift can be eliminated.

MR. BRANDIEN: From New England's perspective, I think we have a lot of things going. We do have to remind ourself that uplift isn't, like the report says, the magnitude is large but the percentage of the overall energy and ancillary markets, it's not that great.

But between, you know, better pricing reserves and the operators' actions with the changes to our capacity market, and hopefully the investments that asset owners make which will translate to more flexibility of those resources, and we are working with New York on the CTS similar to New York and PJM. All those together I'm hoping benefits the operators and we don't have to make as long lead time decisions and impact the market.

MR. ALDERETE: I think everybody understands that uplift is not going to go away completely. There isn't a hidden piece in the market. However, there may be drivers for which we can go after to minimize the uplift.

In terms of the California ISO, we have been actively targeting specific improvements to try to incorporate into the market the actions that we are doing

right now outside the market.

One of them is the flexible ramping product, and the other one is the post-contingency ramping capability in the system.

So we believe that incorporating those through the market to generate a price signal will minimize the uplifts in that regard.

MR. PATTON: I think over time generally the RTOs are doing a better and better job of addressing the underlying drivers. The reality is they're resource-constrained. So, you know, we lay out six recommendations that will all address different aspects of these drivers. They can't do them all simultaneously. And some of them are really, really hard.

So it's going to take some time. I think going in the other direction, things that are likely to maybe cause concern down the road is it does seem like transmission security standards and issues are significantly increasing.

So we need to keep a close eye on that and make sure that the markets evolve as fully as we can to address the transmission security requirements, either through operating reserve requirements with appropriate shortage pricing attached to it, as well as in the capacity market.

MR. DILLON: So it's an interesting question, an

evolutionary question that you asked. Because with the change in the mix that we have going on right now, and the fact that this industry, unlike many other industries, is a lot like an iceberg. There's the small part that you're seeing on top. There's a huge amount of basic needs that are underneath.

As the existing generation stack gets replaced, I think we're going to find that there's not enough cost recovery in new generation in the current paradigm that we have.

It's probably going to require review of what does it really cost to ensure the reliable delivery of energy? And to what extent are the markets actually delivering that?

Not that the market has to deliver 100 percent, but to what extent? Because we all have a tendency to upsize things--let's add this next little item. Well upsize also translate into uplift.

And so I think we're all looking at a total review of what does it take to ensure that the air conditioners come on.

CHAIRMAN LaFLEUR: Thank you, very much. Thank you.

MR. SAUER: Thank you very much, panel. We certainly appreciate learning about the drivers, and we look

forward to hearing about impacts from the next panel.

Let's take a break. So, eleven o'clock. Let's take a break until eleven o'clock.

(Whereupon, a recess is taken.)

MR. SAUER: Okay, everybody. Thank you very much. Actually, I realize that we had one last-minute participant who wasn't--or panelist who wasn't able to make it. Certainly, John, if you want to move over and sit at the head, you're more than welcome to. Or if you want to stay there, stay there. It's up to you. Whatever you're comfortable with.

The goal of this panel is to better understand what impact uplift is having on market participants, and whether we should revisit market pricing rules. Essentially it's to help us understand is uplift a big issue? And understand some of the possible next steps that we can take.

Some of the observations from the paper were, or the paper touched on was the volatility of uplift costs. It appeared high in some of the RTOs, and we just want to better understand whether volatility of uplift cost is an important issue and something that we should focus on.

We also noticed that uplift rates were--tended to be much higher, quite a big higher for that matter, in the real-time as opposed to the day-ahead. Part of it is we

want to understand whether--or how that may be driving participation in different markets.

As part of the issue, or as part of the agenda, we basically said we're going to start with suppliers and then go to load-serving entities, and then financial marketers. We're going to tweak it up a little bit and instead go by subject matter to hopefully have a better discussion.

So sorry for load-serving entities and financial marketers who were hoping to sit on the side for the second half--

(Laughter.)

MR. SAUER: We're going to put you on the spot, so I apologize about that.

We're going to try to follow three general topics. One is market pricing rules related to uplift. The second is transparency--and think of it as both near and long term. And the third will be allocation practices.

It's three topics. We have two halves. We will see how we break it out. It will just depend on discussion. This is a panel on impacts. I know it can be very hard to divorce impacts and solutions. Where possible, keep your comments focused on impacts. We'll cover solutions in the next panel. I know it's going to be hard, but we'll try to keep to that.

Lastly, thank you, Commissioner Moeller, for attending. And before we get to questions, let me just introduce the panel so everybody can hear.

John Rohrbach from ACES. Mark Smith, Calpine. Brian Forshaw from CMEEC. Ivan Kimball from Consolidated Edison. Michael Schnitzer from Entergy Nuclear Power Marketing. Wesley Allen, representing Financial Marketers Association. Peter Fuller from NRG. And Elizabeth Whittle representing Retail Energy Suppliers Association.

For the first question: Uplift seems to be, I guess the best way to put it, an inherent part of electricity markets due to modeling complexities. One thing we want to figure out is how does not pricing uplift related issues into the market, how does it impact market participants' participation in both the near and the long term?

Ivan, you can start--or, sorry, John.

MR. ROHRBACH: Thank you. John Rohrbach, ACES. I'll just take a quick stab at that. I think it's clear that, you know, there's really two types of uplift.

There's what Dr. Bowring this morning called "persistent uplift" which is sort of your grandfather's uplift. Then there's these spikes in uplift which occur periodically, like this past January in PJM when there was $607 million in uplift in one month.

I think if we could separate those two for a second, I'll deal with the latter category first. I think it is a surprise to market participants. It's often not foreseen. But as my documents prefiled show, it's largely a function of overall billings for the month. In fact, so far into this year in PJM uplift is actually less than--for the first six months, is less than, on a percentage of billings basis, less than 2013, including January of 2014 which was unprecedented.

So I think we have to just keep that in mind before we go down a path of over-reacting to spikes in uplift.

MR. SMITH: Thanks. It's Mark Smith. I'm with Calpine and thanks for being invited to the panel, and we appreciate it.

Calpine, as you know, has 26,000 megawatts focused really in three large geographic regions: the Northeast, Texas, and California. Most of that capacity is gas-fired capacity, although we have a very large renewables component in the State of California--just so you understand context.

That said, I don't think any generator wants to live in a world where there's a lot of uplift. Uplift by its definition means that someone somewhere isn't recovering the costs that they bid--their bid revenues, right? That

there's an imbalance. That there needs to be a make-whole payment.

To the extent those make-whole payments are necessary because of any of the variety of reasons that you've heard this morning--because of a capacity constraint being imposed in the energy market; because of units being taken outside the market entirely, for instance many would call it exceptional dispatch--for any of those reasons, those units generally are run at minimum load. Those units that are run at minimum load cannot set the market clearing price.

So we see many, many circumstances in which in the various markets we'll have units that are running at, say at 12,000, 14,000, 20,000 heat rate, running when the market clearing prices are 8,000 or 9,000 heat rates.

And what that tells us is that at the margin there are units that are necessary to run but they're not setting the price. And indeed, those units that are at the margin that aren't setting the price shift that supply curve out to the right, reducing what would otherwise be the market clearing price.

So we see when we have uplifts it's a symptom of a great problem. It's a symptom of units that aren't being priced. Now what does a generator do in that circumstance, and how does it affect us?

Well if the best I can do is recover my variable costs through an uplift payment, I'm going to be disinclined to make capital investments of any kind. The kind of capital investments that in each of these RTOs probably might be no-brainers in other--for other reasons. Things like investment in flexibility. Things like investments to reduce my minimum run times which could be causing needs for out-of-market calls in the first place.

So the units at the margin aren't going to make any investments. The units below the margin, in which case you have for instance combined cycle units in many markets, not all markets, in many markets are below the margin, are looking at less headroom to recover their capital costs and make investments. So they're going to be disinclined to make investments.

So the lower prices that result not directly from a payment of uplift but for the fundamental flaw that requires the uplift really affects capital investment and resource allocation. And by "resource allocation" I would mean how capital resources might be allocated between regions, and how resources within a region are deployed.

For instance, if you have prices that are otherwise lower than they might be because of the clearing, the higher price at the clearing, you're going to see less energy efficiency, less demand response, all the other

functions, too, may not be incented.

So at its fundamental reason, no generator wants to live in a market that has uplift payments because the true and marginal clearing price isn't being shown in that market.

MR. FORSHAW: We look at uplift in the markets in general maybe from a little different construct than some others. We look at uplift in terms of, you know, what are the basic objectives that we're trying to achieve?

It's reliable electric service to consumers at a reasonable cost while providing adequate compensation to asset owners, and recognizing that there are policy and risk objectives that are out there that are going to drive things.

That drives us to wanting to get prices that, you know, can achieve those four objectives. And that means you've got to really look at uplift in the context of the overall markets: Capacity, Energy, Ancillary Services.

And from that perspective, uplift is, you know, as it's allocated to loads anyway, a relatively small percentage of the picture. The staff report acknowledges that. With that said, what we try and do is we try and manage uplift as a part of our overall portfolio management function. We look at how do we minimize our energy costs, you know, our reserve charges, and uplift as

part of that.

That means paying attention to your day-ahead load forecasts to make sure the load that you clear in the day-ahead market is as close as possible to what you're going to see in real time.

It means that when we do our bilateral contracting that we contract for resources so that we're hedged to meet that real-time load in the energy market. And part and parcel of that then also drives down the level of uplift, at least the real-time economic uplift, that gets allocated to our company.

And we probably--our cost of uplift on a dollar-per-megawatt-hour basis is less than half of what the average for the New England Region is.

So I think it's important as you consider further questions in addressing this issue, keep in mind the over-arching, the larger objective in price formation, not just uplift.

Thank you.

MR. KIMBALL: I'm Ivan Kimball with ConEdison. I think that our perspective is that we really kind of agree with all three of the previous speakers. And when you look at the long-term perspective for the market. Obviously we're not short-term players in the market, and we're looking at markets that really work in the long term. And

we're just cautious that, like John said, that we don't react to something that is not persistent uplift; that we take the time to examine what's causing the issue; that we're transparent and open about what is causing the issue.

If it's something that's persistent and is an issue for the markets, we want to make sure that there are sufficient resources available, as Mark said, you know, to make sure that the markets are working effectively and providing the economic incentive for the generating resources that are out there.

So we're trying to work within the parameters of the New York-ISO and the stakeholder process to make sure that we don't change what we see currently as a small portion, or a small impact in the markets, compared to what we think is driving that. When you see gas prices changing from December of '13 to January of '14 like they do, that's obviously a bigger concern for our customers than an incremental adder on that for uplift.

So we're trying to address any kind of systemic issues in the markets.

MR. SCHNITZER: Thank you. Good morning, and appreciate the staff and the Commission hosting this conversation. I think it's timely and important.

I guess I'll start I think really where Mark kind of indicated, that when you have a set of prices that are

insufficient to produce the generator behavior that is needed to reliably serve the grid, that's not a criticism of the dispatch; that's a symptom that there's something wrong with the pricing. And that's the perspective from which we view this.

We don't have any qualms or criticisms with the operators. We're basically trying to figure out how do we get the pricing to be more consistent with what the operators are doing.

So I think before we get into the specific impacts on market participants and baseload generators in particular, I just want to comment for a minute on the metric.

It had a lot of conversation in the staff paper and in the earlier panel about uplift payments as a percent of annual energy revenues, and that metric may have some utility. But I think if you're trying to get a sense of how much off could the prices be, it's not a very good metric at all.

And if you look on an hourly--well, a daily basis is really for transparency purposes of what a market participant can see, but if you look at a daily or a monthly basis with the transparency of the data, and you look and see how much could the price have been off, must the price have been off? How much per megawatt hour above the market

price did somebody have to get paid to perform? You're not going to see numbers like one percent or two percent. You're going to see much more substantial numbers.

And so I think that's, I would suggest for the staff, and I see a little head nod, you already know this, but that if we're trying to figure out how important is this, and how big an impact can it have on market participants, generators in particular, the one percent/two percent old adage about you can drown in water that's six inches deep on average is true about uplift payments.

You know, so we need to look at when they're really big per megawatt hour. And we need to ask ourselves: What are the bad things that can happen from understating prices that massively in those periods of time?

So with that metric in mind, I'd like to suggest a couple of places to look where that kind of price suppression can have a significant impact.

The first, and perhaps most important depending on where you sit, but from where I sit this morning, it gives poor incentives for the--or retaining merchant baseload capacity. If those are the resources that get most of their revenues in margins from energy markets, and if you miss the price badly in some number of hours, that can add up to pretty serious money pretty quickly.

And so I think that's a concern for merchant

baseload, merchant nuclear in particular. Under my hypothesis, the 2 percent isn't right. There are some periods of time when the missed pricing is much more significant.

Right along with that, obviously you'll get the wrong incentives for DR. You'll mute the incentives for DR and for fast-ramp, or quickstart capacity by averaging this uplift payment over a lot of hours, instead of showing higher prices when the prices really should be higher to avoid the uplift.

Perhaps most importantly, after this winter you weaken the incentives for fuel infrastructure development. If you miss price, the energy prices on the coldest days in the winter, those are the price signals for dual-fuel capability, those are the price signals for pipeline expansion, those are prices you don't want to miss.

And to have to try and compensate somewhere else in the market structure for fundamentally that you're missing the pricing signals on cold days is I think a serious problem. That's obviously part of a merchant baseload problem, as well. Those two run hand-in-glove.

And then finally, and I think the evidence suggests this, and staff may have already looked at this, and if you haven't I think you can, that you weaken the incentives for load to offer day-ahead in the extreme

conditions, temperature conditions both winter and summer, when you have a likelihood that prices will be out-of-whack, suppressed, if you will, in real-time.

That's not a virtuous cycle to get into for these markets. That aggravates the need for the operators to posture the system, to protect the system, which they have to do. And as you heard in the first panel, you know that that is a contributor. That's a driver to uplift.

And so we have a vicious cycle. The more we have this kind of chronic, predictable under=pricing under extreme temperature conditions in particular, the more we are engaged in a nonvirtuous cycle which is reinforcing, and we need to break that.

So those are some specific impacts on market participants that I think result from the type of uplift that I've been talking about. I think if we go up one level of abstraction, I think if you look at all those collectively that's a problem that undermines the wholesale markets and is going to lead to higher costs over the long term, which are not good outcomes.

So I think it's a serious issue. I'm glad, as I said, I'll end where I started, I appreciate your having the session because I think these are problems that, the uplift problems are significant and important in the areas that I've just described.

Thank you.

MR. ALLEN: Good morning. My name is Wesley Allen. I'm representing the Financial Marketers Coalition. My job, though, is CEO of Red Wolf Energy Trading. We're a small virtual trading shop that trades in a lot of the ISOs, mainly New York ISO, MISO, ERCOT--I know that's not FERC jurisdictional--and up until recently we were transacting in PJM.

We'll get into some of the allocation stuff, which is perhaps the most important part of this to our sector, but as far as incorporating prices in the real-time I think that that is of the most utmost importance. That's one of the reasons why, you know, we stand behind the ELMP initiative in MISO.

I think as much of the prices you can incorporate in real-time the better it is for the market. You enable the market to react and to price into the day-ahead reliably. And, you know, I heard from panel one that a lot of the drivers behind uplift is the need to, you know, call on units for reliability purposes.

And if you have a day-ahead market and you have a real-time market and you have the shadow uplift market that lacks transparency, you're not going to enable the market to react to price reliability into the day-ahead as much as if you had reliability priced into the real-time.

Furthermore, you mute the investment signals. Some of the other panelists have touched on that. I think that's entirely true. There's not a lot of transparency--actually there's no transparency in a lot of these markets as far as where resources are needed, where the problems exist, and how can we expect the market solution if we're not providing market signals?

I think that's of paramount importance--huge importance, especially as we move forward, especially as the mix of generation online changes that we have the appropriate signals to where voltage support is needed, and so forth.

So anyway, that's about where we stand. And, again, I thank you for letting me be a part of this.

MR. FULLER: Good morning. I'm Pete Fuller with NRG. And as has been said, thank you very much for the opportunity to be here today to talk about this very important topic.

It's always challenging being at the end of a line like this to say something new and different, but hopefully I can convey and maybe present some of the same ideas but maybe in other ways that might also resonate with you.

Uplift has been described by several folks as a symptom, and that's definitely the way we see it. It's not

the issue in and of itself; it's a symptom of deeper underlying price formation problems.

And as we see it, the approach here, or the focus should be on that: How do we get the best real-time prices that best reflect the cost of providing the reliable service?

And that is not always the next dispatchable increment, as is generally the case for an LMP type of model. So we again want to focus on the price formation problem, and uplift is just a symptom and a metric to help us kind of get at that.

When we think about the markets, as well, we think about them in totality and why real-time pricing and uplift as an indicator is so important. Real-time pricing of course affects real-time operations, both production and consumption decisions. So it has huge impacts on what actually happens at the time.

It also translates into day-ahead pricing. It also has ramifications for ancillary service pricing, and it also ties back into capacity market pricing and revenue requirements.

So basically what we've seen over the years is a lot of work--uplift being one piece of it--that sort of tries to compensate for the fact that we don't have good real-time pricing. And I liken it to the bad hip. You have

a bad hip and you start limping a little bit, but you figure it out and you work it out. And pretty soon you've got so many hitches and, you know, ticks that you really--it's hard to recognize what's going on.

We really have to go to that fundamental problem. As far as impacts, NRG and a number of other folks here, we represent obviously very large generation portfolios, very large interests in sort of that traditional role, and LMPs or real-time pricing, and all of the off-shoots and ripples from that have a huge impact on how we think about the markets and their attractiveness for investment purposes.

So to the extent that there are uplift issues, or other quirks that lead to counter-intuitive real-time pricing, it absolutely affects investment decisions and our preferences for where we would allocate capital.

We also represent a substantial load-serving side of the business, and some 3 million customers at the retail level across the country. And so we see it very clearly from both sides. The uplift problem, which again is an offshoot from the real-time pricing, is hugely damaging to our efforts to price and provide to customers predictability and reliability.

Because as has been said many, many times, although I'm not sure I've heard it today, you can't hedge

uplift. It's unpredictable. It doesn't trade out there in the market. You can't take forward positions in it. It's simply a cost of doing business that you have to try to price in. And when we try to price a fixed deal to a customer, that's a risk that's just very, very difficult to manage.

So we see the uplift question really driving to real-time pricing. And at the risk of perhaps moving into the solutions, what we are really looking for is some sort of an intuitive predictability that, as demand on the system goes up, price goes up. As stress on the system goes up, contingencies happen, price goes up.

Too many times we see in all of the pools--and I'm sure there are anecdotes aplenty--we see the situation where a really bad thing happens and the price drops off. The temperature shoots through the roof and we miss the load forecast and the price drops off. It's just very counter-intuitive and it creates the question both from an operational point of view and an investment point of view of what's happening out there? Who's pulling the strings on this stuff? And how do we manage in that kind of an environment?

So I think the appeal that I would put out here for all of us to think about is: Can we get to an environment that has zero to little uplift, and has that

basic feature that the worst the system gets--you know, sort of intuitively--the higher the price goes? So that there's some predictable rationality to that.

So I look forward to further questions. Thank you.

MS. WHITTLE: Good morning. I'm Elizabeth Whittle. I'm representing the Retail Energy Supply Association today.

RESA is a nonprofit trade association made up of independent corporations involved in the competitive supply of electricity. RESA's members are actively involved in retail electricity markets throughout the United States, including in each of the Commission-approved RTO/ISOs.

The benefits that retail competition provides are significant, and the main feature--although there's a wide variation which is why I think it will be difficult to really narrow it down too much in specific contracts if it goes that way today--but the main feature is that retail LSEs come up with and derive and devise fixed-rate products to benefit customers.

And as I think some of the panelists have noted before, if you--if uplift is either having some aberrations that haven't happened in the past, or if uplift spikes or is for some other reason inconsistent over time, it's very difficult to price. Because unlike energy and capacity,

it's unhedgable.

So what retail LSEs are left to do is, you know, come up with an estimate. And that works until you have a January 2014, you know, Polar Vortex, or some other aberration like what happened with reactive supply in PJM last year, or the New York-ISO loop-flow issue in 2008.

And those sorts of things are very difficult to hedge. And what makes the retail LSE different than the incumbent utilities is that, unlike incumbent utilities retail LSEs have no way to defer costs.

So if you were a Consolidated Edison or another big electric utility and you received a large bill, for some reason, you have ways to deal with that. Retail LSEs enter into fixed-rate contracts, generally speaking, fixed-rate contracts for a specified term.

And if you can't recover that cost, then you can't recover that cost, whether it's a legitimate cost of the market or an aberration or for whatever reason. So while I agree that the uplift is small in relation to the overall energy and capacity market, it is a significant risk for retail LSEs in the markets.

So because--and I think that leads to a natural, I think one of the things we agreed with a number of these panelists, is that it is beneficial to have as many market-based costs into the energy and capacity markets so that

they can be hedged. But it's also important to try to come up with a mechanism to address volatility.

And also, just so that I say this disclaimer, the comments expressed in this presentation represent only those of RESA as an organization and not necessarily the views of each particular RESA member.

Thank you.

MR. SAUER: Thank you, all. We certainly appreciate the overview.

Go ahead.

CHAIRMAN LaFLEUR: It's hard to come up with a decent question.

First, just a comment in response to what Pete Fuller said. He is correct that the real goal is to ensure correct price formation in the markets. And our wonderful team here tried to unpack that to look at uplift, look at scarcity pricing, look at mitigation; but if there are topics that we missed or other ways to do it, then that's what the last panel is for and we welcome everyone's comments.

I don't think it's quite like a hip where you can just put in a new one. It's more like a Rube Goldberg machine where--

(Laughter.)

CHAIRMAN LaFLEUR: The question I have is, in the

last panel Joe Bowring made the point that transparency, particularly of consistent uplift in the same places, would hopefully bring market solutions; that the invisible hand would take care of this because people would either put their plants in the right place, or build transmission.

Here we have a batch of market participants. Is there information that you're not getting that would help you act? Or do you have other reactions to that idea? And then I'll turn it to my colleagues. I won't turn this mike off.

MR. SMITH: Great. Thank you. It's Mark Smith. I'll just jump right in, then. You can't price that which you cannot see. And I think in many ways the staff paper highlights how difficult it is to find out not only the absolute level of uplift, but also--and way more importantly--the drivers of that uplift.

I think that as you see concentrations of uplift in a geographic region to a particular unit, it should get easier and easier with diligent review and consideration to figure out what it is that's driving that.

And at this point I'll just give some props to the California ISO because they have begun the process to expose some of those drivers to uplift. They have begun to expose, for instance, how the MOCC, the Minimum Online Capacity Commitment that many of us find distasteful, is

affecting prices.

So, Chairman, you can't price that which you can't see.

MR. SAUER: And we'll go with Mike, then Pete, then Elizabeth, then John and Brian.

MR. SCHNITZER: Thank you. Well I think as to the transparency question and what ills will transparency cure, I think there are some that transparency can help with, local voltage-related uplift being the one that comes most quickly to mind; that if people can sort of see, oh, these are costs that are associated in this very small region and they're associated with voltage, then you can focus attention on transmission or generation alternatives, et cetera.

But I think even transparency in those limited circumstances, in my view limited circumstances were as helpful, it's no substitute for pricing. And the far more powerful tool is pricing. And if I can just elaborate on a couple of examples of that based on the first panel.

What you heard from the first panel this morning, my words, I think, but I think a fair summary, is that there is a pretty good substantial driver of uplift which results in a mismatch between the assumptions that the operator made when they protected reliability and dispatched the system and the assumptions embedded in the pricing algorithm.

And transparency won't do a thing about that class of problems. The only solution to that is to conform the assumptions underlying the pricing algorithm to the assumptions that the operator was making at the time. And Dr. Patton had some comments about operating reserves, and fuel reserves, and so I think that that is a whole class of solutions which I hope gets a lot of attention in panel three and is totally divorced from transparency. Transparency is not a way to get at that particularly.

Similarly, the remaining uplift issues associated with the nonconvexity, the fact that now in this instance that cost I incurred a minute ago is sunk, and so now my cost, my marginal cost looks lower. Being transparency about that is really not going to be particularly helpful to somebody who wants to invest money in improving their fast-ramp capability--because all they'll know is, if the prices were right they would've made money because they have increased transparency about what the cause of the problem is, but they won't actually have the opportunity to earn the money.

So, you know, transparency in my view is a good and necessary first step, and it can be helpful in certain limited circumstances, but I would urge the staff and the Commission to keep their eye on the pricing goal as being the one which has the largest payoff and the largest benefit

here.

Thank you.

MR. FULLER: Yeah, I think everything that's been said so far rings true to me. I think, you know, the first goal of all of this stuff, whether it's a chronic, concentrated uplift situation or more transient kind of stuff, is to get those assumptions or constraints into the real-time model so that the pricing actually reflects them.

Then it becomes a question of the accessibility, if you will, or--of those dollars. If someone comes in to try and access that and solve a problem, do we have essentially a binary situation where it was constrained yesterday but you built your new plant and now the constraint's gone so this is a really cheap area now.

And that's a tough problem, and I don't pretend to have a solution to it, but I would suggest that there's probably work that ought to be done in, you know, just the demand curve kind of realm. As I mentioned in my opening, the idea that we don't all automatically go from 0 to 100 in general.

And the system ought to be structured in a similar way that as things are getting worse you should see some effect of that. And so I don't have a real answer to it, but I think that's another characteristic we ought to be

looking for in solutions both to chronic localized things as well as general pricing algorithms.

MS. WHITTLE: From the retail LSE perspective, transparency is critical and would help I think the retail marketers in their ability to price their--derive a price for their product.

In terms of transparency on the retail LSE, it's important to know the reasons for the uplift. And an example is that if there is an anomaly in an uplift account and it continues for a week, a day, a month, a year, retail LSEs are faced with deciding, well, what's causing this? We don't know. Is this a new issue that's going to be affecting contracts, long-term contracts? Is this something that's a blip? How do we price it?

All those kinds of things are very difficult to deal with when we don't know the reasons. So understanding the reasons for the uplift, the likely duration, those sorts of things will go a long way in helping retail suppliers.

Because when retail suppliers price their products, of course, for energy and capacity there are hedges available, and for uplift there aren't hedges. So retail LSEs build in premiums.

And in developing those, uplift is a component of it. And so you'll have better pricing and premiums to benefit the retail LSE and retail customers ultimately to

the extent you can manage and understand these and price these accurately.

MR. ROHRBACH: Thank you for the question. I'd like to again just break it up into the two categories that I've laid out for the uplift charges.

One is the persistent uplift. And again, the PJM State of The Market Report is very detailed. Nevertheless, one cannot necessarily understand where the persistent uplift is occurring such that I would potentially be able to make an investment, or a merchant entity I would think, make an investment to relieve that, or to capture that. It's just not--you know, there's a lot of data there, but it's just not--I'm just not sure the market is really aware of it.

That being said, when we move to the second category, which is I'd say the--so let me go back to that for a second.

I think what the State of The Market has recommended is that, and my background materials point out, is that confidentiality rules were designed to protect competition. To the extent that they do not allow competition to occur, that is something that should be addressed.

Moving on to spikes in uplift, I think Mr. Schnitzer and Mr. Fuller make interesting points.

Mr. Schnitzer in particular points out that we should want to move everything--well, suggests that there's aspects of uplift in the huge uplifts we had in January, that transparency would not necessarily help.

That's probably true. I would say, though, that he recommends that we have two possible solutions. One is prices. And so in PJM we have two main price vehicles, one we use an LMP market and a Capacity market. If we take the latter as a vehicle to express that, we run the risk of paying a Demand Charge for something that's a rare event, and we'll pay it many times over than what the initial uplift cost is, even though it potentially might resolve the issue that he's talking about.

And I'll just give--the Chair asked us to give a concrete example, and I think I can tie together a concrete example of two things here.

One is the transparency and one is an example of how something may or may not help uplift. And that is, the State of The Market Report, to the extent it can, I believe, and I haven't discussed this with Monitoring Analytics, but it presents as much data as it can. And in reading it, I observed that in its autopsy, if you will, of January '14, it discussed, I think it was page 153 or 157, it's in my slides, what happened on six days in January.

And it has a graph, and there are some words, and

if you basically draw a line across the graph with a ruler you can almost get to the amount of megawatts that are committed in the off-peak hours in January.

In PJM--and probably in the East, who knows--the question is what would those payments, what do they really reflect? What's going on there?

I think if you read that State of The Market you can sort of understand that what's going on there is a reflection of a ratable take constraint on a pipeline, and this is what some of the panelists have addressed, is is that something that's amenable with changes to an RTO's pricing, either Energy or Capacity?

And it may not be, and you may end up in a situation where you're essentially paying more prices daily or for Capacity, for example, or Energy, and you still haven't resolved what is the pipeline's ability to effectuate a ratable take constraint?

I mean, it could be. I'm just saying we ought to tread lightly in that regard. Thank you.

MR. FORSHAW: Thank you. I guess my first response to the question from the Chair is that transparency is sort of the first step in understanding what's going on. Since I have Ray Hepper (phonetic) sitting right behind me, I'll take the opportunity to give props to ISO-New England.

Every month when the NEPOOL Participants

Committee meets, the ISO's Chief Operating Officer makes a monthly report to the participants. Inevitably, questions about uplift come up, specific instances of uplift, specific days, and VOMCI does a wonderful job of walking us through, giving us insights into what's happening, why it's happening, and some idea about whether it's a predictable event or not.

An observation that I made in my prepared remarks is there's a strong correlation between the incidence of real-time economic uplift in New England and days when the ISO has to take actions--when the day-ahead commitment schedule didn't provide enough operating reserves and replacement reserves to meet the Minimum Requirements for the region.

And, you know, that's something people can focus on. There's information that's out there--the Morning Report publishes the level of supplemental commitments as of 8:30 every morning.

The challenge, though, is being able--it's not being able to understand necessarily, it's being able to anticipate what those conditions are to try and take action for it. And that's going to be something that, you know, is more of a challenge for folks than anything else.

Thank you.

MR. SAUER: One quick question. I think one

thing I forgot to mention is that generally the RTOs and the Market Monitors can respond, or add additional discussion if they feel it would help facilitate the discussion here.

I know that the ISO made one, and also that PJM reports pointed out, just giving a quick look over to see if they want to discuss it. You can come up to the table if you want.

MR. BOWRING: No, this is fine. So just very quickly, so the question was about transparency and the extent to which transparency can help solve uplift.

Of course it can't solve all uplift, and hopefully I didn't say that it would. However, when there is concentrated, persistent uplift, no matter how closely you read the State of The Market Report, you don't know what it is. And that is by design, because it's confidential.

And I'm sure there are confidential things in New England briefing, as well. You don't know what companies and what units are causing uplift. And when they're persistent, transparency is really the only way to solve it other than, in addition, adding it to RTEP.

So I agree that it's not the entire solution to all levels of uplift, but you have to separate them. And the part I was talking about was concentrated, persistent uplift. And I do think there is no alternative solution. As we've seen in PJM, we've had the same units receiving the

same amount of uplifts for 15 years. Clearly something is not working.

MR. PATTON: Okay, to give sort of the counterpoint and a caution on how much we can rely on transparency, I mean transparency is always good. And so there's no argument I think that can be made that we shouldn't be more transparent. I just don't know what people have in mind as far as what solution is going to come about.

If I--I think RTOs vary in the level of transparency they provide, but in no case do I see a solution really emerging from a private market participant, just because they happen to know that uplift is occurring somewhere.

We had uplift in the Upper Peninsula in Michigan in MISO that was large voltage-related. Everybody sort of knew where it was and knew why it was occurring. Nobody is going to do anything about it, regardless of how long it lasts and how big it is, just because there's no product that somebody can make money off of by investing something there.

So if we don't fix the pricing and don't create a product that reflects some of these missing requirements, then you can be very transparent but not really solve the problem.

I think where transparency comes about is perhaps in the planning process, that if you know the problem that is causing reoccurring uplift, then from a planning perspective you can upgrade transmission or do something else. But largely those planning processes are driven by the RTOs, and they know what's going on.

So I feel like that part is already being handled. So I would sort of endorse what Michael Schnitzer said. That is, that you need products and you need pricing. Transparency alone I think will have a limited impact.

CHAIRMAN LaFLEUR: Thank you.

MR. SAUER: Going off a couple of those remarks, let me just ask a question. I think certainly Mark pointed out incentivizing, not having the money to incentivize flexibility, or particular aspects. David just pointed out not having products.

What is it in market pricing today that gets it wrong in terms of--or that results in incorrect price formation. Is it not incentivizing, or not valuing particular attributes of a resource? Or what can be improved? Mike?

MR. SCHNITZER: Yeah, let me give a partial answer because any of us could probably go on for a long time about that. But I think that, you know, the pricing problem that I want to talk about is the one where the day-

ahead market clears based on a certain set of constraints and security requirements.

The ISO or the RTO determines after the fact that that just doesn't provide enough of something for tomorrow, makes some supplemental commitments, and we have a pricing algorithm that is based on the assumptions that underlay the first set of analyses not the second set of analyses.

That just means we got the Energy prices wrong, right? And the consequence of that is going to be, if it's a winter day, you know, that we--the operator determined that we needed more reserve and we're going to incur a substantial cost to provide that additional reserve. But the co-optimization and the pricing of the reserves, both in day-ahead and real-time didn't reflect that.

The legion of bad things that can come from that, you know, the list is long. But it's all the same--it's all the same thing. It's basically saying the day-ahead price is probably wrong because it didn't have the reserve, the extra reserve quantity and price embedded in it, the dynamic reserve kind of calculation. And the real-time price was certainly wrong for the same reason.

So that's basically going to provide inadequate incentives for somebody to invest in fast-ramp capability because you just crushed what would otherwise have been, you know, 14 hours of modest prices, and then a big increase.

And so you've basically done away with that through your pricing algorithm.

You've under-priced the value of fuel security in that day, substantially. So it's not--I think in my mind the solution to this is not to say the problem is I don't have incentives for fast-ramp, what's the tweak to the market that will fix that problem? That would not be the end of the telescope that I would, you know, focus on.

I would basically say the problem is I have a mismatch between the constraints that underlay the pricing algorithm and the constraints the system operator actually used. And I have to get consistency between those constraints, have the prices then fall out of that, and then I'll be better off than I am today.

There may still be some more things to do, but at a first blush if we can't get congruence between the constraints and conditions embedded in the pricing algorithm and the constraints and conditions that the operator was basically making real decisions based on, then it's going to be hard to make much progress if we don't get that piece right.

MR. SAUER: Pete, Mark, Brian, and Wesley.

MR. FULLER: I think the question was asked as what are the problems. And I think as Mike decided to focus on one, and I'll just focus on one rather than trying to

come up with a laundry list.

One that has continued to confound me throughout the years is the issue of, you know, it could be a fast-start resource, it could be some other operator contingency action, or demand-response activation where, because the algorithm says that we will price our Locational Marginal Price on the next dispatchable increment of Energy, we get turned-around prices.

You know, the example that I always think about is we're cooking along, everything's under control, you've got to pick a number, a $50 a megawatt hour unit on the margin. Something goes wrong. Something happens that requires us to ramp up some quick-start capability quickly. And so that's maybe $150 a megawatt hour.

Generally you might see that price for a very short period, or not at all. But as soon as that block energy displaces that $50 unit, the price goes back to $50; notwithstanding the fact that we had this contingency, the system is under stress, we're running much more expensive stuff to keep the system together.

So again that idea that we don't always capture in the real-time what it's really costing us to run the system.

MR. SMITH: Thanks. My message is very similar, and that is: How you dispatch the system in real-time

should determine how prices are formed.

In each of the organized markets we have these incredibly complicated machines on a day-ahead and on a real-time basis to solve prices. Something happens once that market closes. And that "something" is generally and often what creates uplift.

I might say that some of the most dangerous people in each of the operators' organizations in terms of uplift are those that run that residual unit commitment process. That is something that happens after the markets clear.

That residual unit commitment process can be triggered based on any variety of factors. And you've heard throughout the day many of them. System operating limits. Any kind of capacity constraints. Ramping constraints that we saw pop up in the West with the incredible penetrations of renewables that we've seen.

And once we see those, and once we understand what those changes are, we're not telling the operators to not do it, because they need to do what they need to do for reliability. But show us what it is.

That's a necessary but not sufficient condition. Once they show us what they have done, find ways to price it. And I think there's a lot of creativity in this room and out there to find ways to price many of the uplift

issues--certainly not all of them.

I think we all recognize that there are elements inherent in multi-interval forward markets that create uplift that are simply unavoidable. So show us what you've done. Find a way to price it. Base it on what you've done in real-time.

MR. SAUER: Brian.

MR. FORSHAW: Again, getting back to a comment I made earlier, I think part of what we see emerging is, in terms of market results, is--really stems from the fact that the commitment schedule that comes out of the day-ahead settlements doesn't provide the system operators the resource mix that they're going to need to meet real-time needs.

And, you know, again the analysis of trying to unpack what's going on that we've done on days when the system operators have to make supplemental commitments--and they have to make them. I don't think anyone here would dispute that that's their job one to do that. But on days when the supplemental commitments in New England, since January 2012, the day-ahead LMP actually was less than the real-time LMP.

So in fact it didn't depress prices. I think, although I don't know, the reason for that is that we don't have a co-optimized Energy and Reserve market in the day-

ahead which we do in the real-time. So when Reserves get tight, the LMPs go up.

So again I think it's important when we focus on this to look at solutions that make that day-ahead process provide what the operators need, and then a lot of these problems start going away.

MR. ALLEN: Thank you. A lot of comments from the panel about the differences between day-ahead and real-time causing some of this uplift. One of the things I would point out is that the types of transactions that we do, virtual transactions, or I like to call them "competitive bids," how do you profit from doing that type of activity?

The only way you can earn a profit is if you converge the day-ahead and the real-time. So inherently the entire existence of what we do--I mean aside from competition and market power mitigation and stuff like that--is to converge the day-ahead and real-time.

And we saw in the FERC paper that there's a high correlation between the degree of uplift and the correlation between day-ahead and real-time.

So here's a sector of the market that is tasked with helping solve these problems. And if you think about it, if you price a lot of this reliability into the real-time, you enable the financial participants to help converge the day-ahead and real-time and thereby commit the

reliability units that are needed in the day-ahead. So it's of profound importance.

Similarly, if you look at the amount of virtual activity in the different ISOs and then compare it to the amount of day-ahead and real-time spread in those different ISOs, it's a very telling story.

In the ISOs that have a lot of virtual activity, the delta between day-ahead and real-time is smaller than it is in ISOs that don't have the virtual activity. I don't want to touch too much on allocation just yet, but that's the driver behind why you have activity in some markets and not in others.

MR. SAUER: Certainly we'll throw out some allocation questions in the second half and look forward to it.

(Laughter.)

MR. SAUER: I have failed at my responsibilities, in that it's ten minutes past lunch--I'm sorry. Commissioner?

COMMISSIONER CLARK: I'm going to help you fail even more here by asking one last question.

(Laughter.)

COMMISSIONER CLARK: So a couple of things stick in my mind from this morning's conversation in total. One would be that uplift is a symptom of an underlying cause, an

underlying problem in the marketplace.

That problem is something that's not going to be fixed by itself; it's going to have to take an affirmative change by industry or FERC. You can't correct for all of it, so you've got to focus on the big-ticket items.

To kind of bring a little bit of clarity to FERC's work going forward, if you had to pick what is the one big-ticket items that has the biggest dollar value impact that we should be making an underlying change to fix, what would it be?

And hopefully you can handle it. It should be a fairly focused question, so you can do it fairly quickly before lunch.

MR. SAUER: We'll just go left to right.

MR. ROHRBACH: Thank you, Commissioner, for the question. It's an excellent question. I would say that we have to look at this from a long-term perspective, and it depends what product we attempt to roll this into.

So, for example, if we attempt to roll everything into the PJM Capacity Market, that might be--we might end up worse off on an annual basis than paying sporadic uplift once every 10, or 5 to 15 years.

On the other hand, I think some of the confidentiality issues that Dr. Bowring alluded to, if they could be remedied we might see an entry that could deal with

the persistent uplift issue.

I'd say that I just would ask--so I'd just leave it there.

MR. SMITH: Commissioner, it's Mark Smith from Calpine. The one thing we think would have the best benefit is finding ways to price circumstances when a strong number of units are sitting at minimum load.

Those units at minimum load, or if they're at maximum load, typically are not allowed to set price in these markets. But they shift the supply curve out to the right and reduce the otherwise clearing price. That we think would be the single biggest item that would benefit these markets.

MR. FORSHAW: Commissioner, as I said before, to me the biggest single thing, or the initial effort where the Commission should focus on is to try and help assure that the results that come out of the day-ahead commitment schedule provides the system operators what they need in real-time.

We've been working on that in New England for awhile now. Additional areas that we're investigating, we haven't concluded yet, but would include allocation of uplift costs; and also working on getting the price impacts, reserve price impacts, incorporated into the day-ahead dispatch.

MR. KIMBALL: I think that the biggest issue would be first identifying where the persistence occurs, whether that's a day-ahead or real-time mismatch, whether it's an information issue, and making sure that those are the ones that we address.

I think that when we have issues where it's either infrequent or something that is driven by a particular event, I agree that the market itself is not always going to present that solution. So we need to really focus on the persistent items that are causing market inefficiencies.

MR. SCHNITZER: Commissioner, my hypothesis I think would be the same as Brian's, that there's a strong correlation between and after a close of the day-ahead market set of supplemental commitments and then uplift that follows from that. Although that's something that the staff could verify, and I would encourage them to look at those data.

But under the assumption that that's true, that that is, you know, kind of a big driver of when we see uplift incurred, then I think the creation of different types of Reserve products that would price what the operator was doing into the real-time and the day-ahead pricing would accomplish what Mark was describing, that it would avoid all these units sitting at minimum and having nothing to do

about pricing. The co-optimization of the Reserves would set the prices at a higher level.

So if that hypothesis is not true, then there might be a different first priority, but I think that would be my best guess as well, that that is the number one place to look.

MR. ALLEN: I guess the number one thing I would look at is ultimately the allocation. And, you know, cost-causation, just and reasonable rates are terms you hear all the time, but the reason why that matters so importantly is that it creates the proper incentives.

If you are participating in such a way that you're causing more uplift, and then you're allocated more cost, you stop doing that type of behavior. And the converse is true, as well. If you're transacting in such a way that you lower uplift and you get a credit, and then you want to continue doing that.

So it creates the proper incentives in the market. It's not just that it's just and reasonable, it creates the proper incentives so people can own their own through the market mechanism lower uplift.

MR. FULLER: I think my number one would be a variant on some of the things that have already been said, which is basically to reflect in real-time pricing the full cost of what it takes to maintain the Energy and Reserves at

the time--be that units at min load, units quick start, units supplementally committed, operator actions, demand response activation, whatever it is, but it would be to find ways to reflect that full cost in the real-time price.

MS. WHITTLE: For the Retail Energy Supply Association, I don't know that I can pick a particular one. I think reserve issues, operating reserve costs in PJM allocated to deviations is an issue that they're very interested in. However, I'd have to survey everybody and see if anybody had consensus.

So I think I'll have to pass on picking one particular one and get back to you with a supplemental comment, if there is consensus. Thank you.

MR. SAUER: With that, we will break. Enjoy your lunch and caffeine. We'll convene, we'll give everybody about ten extra minutes, so we'll begin at 1:10.

(Whereupon, at 12:45 p.m., the technical conference was recessed for lunch, to reconvene at 1:10 p.m., this same day.)

AFTERNOON SESSION

(1:12 p.m.)

MR. SAUER: If everybody will take their seat, we'll continue the panel in a couple of minutes.

(Pause.)

I hope everybody had a good lunch and finished it with plenty of caffeine. Uplift is not--or is a dense, dry topic at times--

(Laughter.)

MR. SAUER: But we will move straight into allocation practices, and from the time we have left we will get into transparency. I know that Leslie was very kind and itching to talk about allocation practices, but held off, so we'll move on to that.

Before I ask a question, would you like--

CHAIRMAN LaFLEUR: No, thank you.

MR. SAUER: No problem. As we said in our staff paper, one of the observations were that real-time uplift charges were quite a bit higher than the day-ahead charges.

I'd like to get a sense on what incentives those high real-time uplift charges may create. So is it incentivized participation in one market versus the other? And how--assuming that those charges were equal, more or less equal, how would your behavior differ?

Brian?

MR. FORSHAW: I'll start off again. I think I alluded to it in the earlier session before lunch, but from our perspective, you know, the uplift--real-time uplift allocation really does make a difference in how we perform. We actually try and incorporate uplift as part of our decision criteria when we plan our portfolio.

In New England, real-time uplift charges are based on deviations, load deviations. So the difference between your day-ahead cleared demand and your actual real-time loads, you know, the bigger they are, the more uplift you get.

We also, when we plan our portfolio to cover our Energy costs, we procure--make purchase contracts that settle in the day-ahead. And so that's just part of the whole process.

Probably about three years ago, maybe a little longer, we invested an awful lot in our day-ahead load forecasting capabilities, with a goal of really reducing as much as we can those real-time deviations.

And part of that consideration was that's one of the tools we have in our toolbox to try and minimize the uplift that gets allocated to us. It also, you know, helps out because that assures that we can clear, you know, the resources we use to hedge our load obligations, which clear in the day-ahead, also match what we see in real-time.

So in terms of that, allocation makes a difference. Allocating to deviation makes a difference. And, you know, that's a tool that we use and we think others can use when you look to settle to sort of minimize the composite costs of energy, ancillary charges, and uplift charges.

MR. SAUER: John, then Wesley.

MR. ROHRBACH: Okay, thank you. I just wanted to just contextualize PJM for a second.

Unlike I think ways described by Brian for New England and PJM, there is a deviations charge. I think the footnote in your paper nicely summarizes it. I think I'd add to it, and I can't recall it exactly, but if there's the absolute deviations vis-a-vis real-time, so even down is a charge--is charged BOR for deviations.

To the extent, though, that there's real-time uplift in PJM and it's due for say the reliability bucket, let's call that, and that's due to conservative operations for example as it was in January, that is a real-time necessary and exigent circumstance that has to be reflected, a cost that has to be incurred.

And as my previous panelists pointed out, that's just necessary and part of life. I think to tie it to an example, I know of a co-operative that went from paying roughly in the $100,000 range for uplift, total uplift in

December to $5.2 million in January.

So this captures all the topics we've discussed this morning, plus then this cost allocation topic. The thing, though, is that when you have this real-time exigent circumstance that it's simply necessary to pay, or to reflect conservative operations in payments, that is--it's rare, but it does get allocated in PJM to load in real-time and it's hard to imagine another place to put it.

So I can't really quibble with that. So thank you.

MR. ALLEN: Thank you. Allocation is probably my favorite topic.

(Laughter.)

MR. ALLEN: It would probably be a good idea to just back up a little bit. As I stated earlier, in the company I own we transact the New York ISO, we transact in MISO, it transacts in ERCOT. Up until recently, we were transacting in PJM.

And the reason we are no longer participating in the PJM market in any capacity is because of the change in allocation, or potential change in allocation methodology of uplift. That's very recent.

So I thought it would be a good idea to kind of give you a little bit of an education, if you don't already know, but there's two basic products that we transact.

There's an Energy product, and then there's a Transmission product.

Not all products exist the same in equal markets. They all have different names. Energy product, that's what you know of as an INC and a DEC. And whenever you deviate with an INC and a DEC, you're charged an Energy Uplift.

There's also a transmission product which is a simultaneous buy-and-sell. There is no actual injection or withdrawal of energy, or even a virtual injection or withdrawal of energy. It is a purely transmission position. It's a spread.

It's a spread between two nodes within the footprint of the ISO.

MR. SAUER: Commonly called "up-to-congestion" in PJM?

MR. ALLEN: Well it's up-to-congestion in PJM. It's point-to-point in ERCOT. So it's a different product--the same product, different name.

To go a little bit deeper in that, I think it might be helpful to think about how that transmission product that has no energy deviation, how can it have energy uplift, how it would be treated in different markets.

New York-ISO doesn't charge uplift to virtuals. So obviously it wouldn't be charged any there. MISO nets their virtuals. So you wouldn't have any uplift there.

California nets the virtuals, so you wouldn't have any uplift there.

The point-to-point product, the transmission product that exists in ERCOT is charged a penny-and-a-half day-ahead make-whole payment.

In MISO, MISO's a complicated allocation for virtuals, but it makes a lot of sense. They have two different--they have two basic rates. They have the CMC rate, which is the Congestion Management Charge, and that's what would apply to a transmission or basis trade.

They also have the DDC rate, which is the Deviations Rate. That's what would apply for someone who, you know, virtually injects or withdraws electricity and it doesn't show up in the real-time.

So that's a broad overview of how it works. But the MISO construct I think works really well. It makes good sense that if you have an Energy deviation you can be charged a deviation rate.

And to give you an idea of how extreme that rate is, it can be pretty high. It can be pretty volatile. But it's based on cost causation. So if your specific transaction causes uplift to be incurred, I mean the rate could be as high as $30 or $40 a megawatt. On average, it's $1 a megawatt. That CMC rate, which is what applies to someone who simultaneously is buying and selling and there's

no Energy deviation, that rate can also be volatile but on average it's about 2 cents a megawatt.

So if--and in PJM, PJM is a different animal. They kind of view everything as a deviation. Everything has to pay. And I kind of--I like analogies, I really do, and I was trying to think of a good analogy for this. And the best thing I came up with is the gas guzzler tax.

I think in MISO, what they do is they say, you know, if you consume a lot of petroleum, if you drive a big SUV, you've got to pay the gas guzzler tax.

In PJM, they don't care if you ride a bike; they don't care if you take the bus; everyone pays. And unfortunately it's that type of allocation methodology that is, you know, is going to have a profound impact on the amount of virtual transactions in their market.

ISO-New England, I didn't even tough on ISO-New England. When I was putting together our materials for this, we had to dig pretty deep to figure out what the rates are because no one transacts in ISO-New England that I know of, no virtuals. And I think it comes back, you know, to what you see in the FERC paper.

If you look at a day-ahead and real-time spread in ISO-New England, it is the highest of any of the other ISOs. It is because the allocation is so high on virtual transactions that how can they converge the market? They're

squeezed out. And it doesn't take much. These are low margin transactions.

In PJM, switching back to them for a minute, they did some analysis kind of unrelated to INCs and DECs, but they did some analysis on what's the average profitability of an INC and a DEC. I think they studied five days, and I think they came back with 52 cents a megawatt. And that's, you know, 52 cents for a financial marketing company, that's pretty good. That's a great rate of return.

Unfortunately, the operating reserve allocation is $3.38. So there's no way you can converge the market. The allocation is too high. You know, not to beat up on PJM too much, but it hit a nerve point. As a part of EMU, Energy Market Uplift, sorry for acronyms--

(Laughter.)

MR. ALLEN: As a part of EMU, Energy Market Uplift Task Force in PJM, we asked some questions about how many of the incremental offers and decremental bids in PJM's footprint are at West Hub?

And this is a very interesting topic for me. Forty-one percent of all decremental bids in PJM are at West Hub. Fifty-two percent of all incremental offers in PJM are at West Hub.

So what does that tell you? That tells you that at a minimum 41 percent of all the virtual transactions in

the PJM footprint are settling against someone else's virtual transaction, which means they have no impact on power balance; they have no impact on unit commitment; they have no impact on dispatch. But yet all of them are paying uplift, uplift that they have no probability or possibility of creating.

And while we're speaking about unit commitment, I love it whenever the justification for virtual transactions is that they commit units, or they change dispatch. I think that's great. Isn't that what you're supposed to do? Aren't you supposed to commit units? And aren't you financially incentivized to commit units that lower uplift? And if you don't do that, you lose money. The economic incentive is already there so that you don't continue to do that, self-limiting.

So if you ever hear anyone say the reason why a certain transaction should pay uplift is because it commits units or it changes dispatch, I think your next question should be--and the question that's never been answered in the PJM footprint--is: Is that commitment, or is that change a positive or a negative impact?

And the principles of cost causation would drive you to say that if you lower uplift by changing the commitment, by changing the dispatch, then you should be credited. And if you increase the cost of uplift, then you

should be charged.

And that's what's so great about the MISO construct. It follows the strict cost causation principles to the point where you create the proper incentives for the virtual transactions in the market.

Now unfortunately every time I come up to FERC, I end up speaking on the benefit of the products to the market. That seems to be a frequent point of discussion: Do virtual transactions actually add any value?

I think it's unfortunate that we have to go there every time we're here. Kind of in line with transparency, I don't think it's unrelated, we've asked for studies to be done by independent economists to ascertain the value of virtual transactions in the market.

We've started down that path. And when it comes to releasing the data--with a signed confidentiality agreement to an independent economist--we hit roadblocks at every ISO.

And unfortunately we're in a situation where we have to prove our worth, that we have a place or a reason of existing in these markets. Sometimes it's better to be lucky than good, and I think we got a little lucky.

A guy by the name of Frank Woloch, who used to be part of the California Independent Market Monitor--or, I don't know, part of California's Market Monitor--and he's

also a Professor of Economics at Stanford University, decided to do some analysis on the impact of what they call "convergence bidding," which is INC and DEC markets in the California ISO.

What he found is in the first year of convergence bidding in CAISO, the ratepayers saw $70 million lower cost to consumers. And if you're concerned about environmental concerns, they also saw a 500 million ton reduction of carbon. And that's just attributable to virtual trading.

And I think oftentimes when we talk about the value of virtuals, INCs, DECs, Congestion products, we talk about the competition. We talk about mitigating market power and stuff of that sort. So I think if you want to study where our benefit is, look at where it was and where it's not. Look at where it wasn't and it is. Because I think it's a little bit more difficult to ascertain the value of it in markets where, what's the value of competition in a market that already has competition? It's much more difficult to ascertain.

So I think California is a great example. It's a small RTO relative to some of the others, so $70 million in a small ISO in first-year virtual trading I think is pretty good.

But, yeah, look at it in New England. You know, how--what's the impact been of the lack of competition in

ISO-New England since the allocation of virtual transactions killed virtual transactions in that market?

So, anyway, I'll kind of leave it--well, one last point--

(Laughter.)

MR. ALLEN: --and then I'll get off my soapbox. In the Energy Market Uplift Senior Task Force in PJM, there's a bunch of different proposals that are out there. And I picked on PJM a lot, so I'll pick on the IMM a little bit.

The IMM's proposals, as far as how it charges uplift to a transmission deviation, is that a transmission deviation will pay twice the uplift. So that means if Peter here from NRG puts in a path from A to B, and I put in a path from B to A, and we both clear, same volume, same hours, I get charged twice, he gets charged twice; meanwhile, if a generator trips offline and actually causes uplift, they get charged once.

And if you want just and reasonable rates, if you want something that makes sense, if you want the proper incentives in the market, that type of stuff cannot exist.

Off the soapbox.

MR. SAUER: Michael, then Elizabeth.

MR. SCHNITZER: Well I'm going to switch gears just a little bit, and maybe this is kind of a little bit my

role. I just want to talk a little bit about the allocation issue versus the pricing issue, and in particular just to make the point that I understand that allocation is important and I understand more than I did 10 minutes ago about some ways that it is important, which I appreciate.

So I'm not here saying that allocation doesn't matter, but it's not a substitute for what we spent the before-lunch period of time talking about. I think--I won't put words in Wesley's mouth, but he might well agree that the best form of allocation would be to put as much of it in the prices as we could, the real-time and the day-ahead prices, so we wouldn't have anything left to allocate.

And I think that ought to be the, you know, the first best objective, if you will. And just, Will, just one comment on the way you sort of intro'd and framed this, is that it is true that, as the staff report shows and as the ISOs and RTOs report, that more of the uplift is, in quote, the real-time.

But again as we talked about before, before lunch, and as you heard from the first panel, what that really captures is all the uplift that was occasioned by everything that happened after day-ahead, which includes the supplemental commitments and all that other stuff.

So I think that we really just, you know, can't let ourselves think about well that whole bucket is just

really what actually happened in real-time. I think a lot of it happens right after the day-ahead market clears and supplemental reserves and supplemental commitments costs are incurred, but they're not put in the pricing algorithm.

And allocation of uplift is not going to do anything about that. It's not going to solve any of the problems that we talked about before the break.

MS. WHITTLE: I just wanted to highlight for a moment the effects of the aberrational or cold weather Polar Vortex type spikes in the, and in particular in PJM with the BOR accounts. And I think the extraordinary costs are somewhat minimized as, well, this is going to happen sometimes.

And I guess I disagree. I think if some of the things people have been talking about today actually do result in some changes in uplift, those sort of things may not be as significant and severe.

But just to put this in perspective, in the PJM in particular their Balancing Operating Reserves I think in January 2014 was approximately $550- or $560 million. One-third of that was collected in the deviations bucket, so a hundred and seventy something million. And the rest was collected in the Reliability.

So if you were really good with your deviations, you may not have paid much of the $170 million, but there

was nothing you could do about the, you know, the rest of it. And the impacts on retail LSEs was devastating.

You know, the retail LSEs have long-term fixed-price contracts, as we spoke about. There's no mechanism for recovering those sorts of costs generally, unless they were reflected, you know, in the beginning in the pricing.

And so I think--well, to be sure we hope it doesn't happen very often. The fact that it did was very significant for the retail LSEs. And even though the load benefits from the reliability aspects of the actions implemented and the costs incurred, load didn't really pay. The retail LSEs absorbed those costs.

MR. SAUER: Picking up on your--oh, sorry, John?

MR. ROHRBACH: Briefly can I respond to my colleague, Mr. Schnitzer, here? I mean, there's aspects--when I was referring to the real-time, I was really referring to everything after--you pointed out that it's really either in lieu of or right after the day-ahead market. So I was just, for shorthand, using that.

But there's aspects of that that are operator decisions that are not always--you cannot capture the LMP because they're simply conservative decisions, double contingencies, they're just hard to reflect.

So I'm not sure if you're assuming that we can

all reflect that ahead of time, and that's just what I would throw out there.

MS. SIMLER: I've got one thing to add, Mr. Schnitzer. When you respond to that, can you kind of unpack this idea of the products, the products that you're seeing developed in the ISOs, or through the stakeholder processes, or other ideas you have? Thank you.

MR. SCHNITZER: All right, I'll try.

So I think, you know, John, I would agree with you that they presently are not reflected in the price, and I think that's sort of the start of the problem, is that the pricing algorithm that is used, be it day-ahead or real-time, you know, is not in most cases designed to reflect the fact that there was a double contingency constraint.

There was a posturing of the system in a more--you know, in a more conservative stance because of something somebody was concerned about, or that there was a fuel vulnerability issue that was actually reflected in either the day-ahead or the supplemental, you know, kind of commitment kind of thing.

So they're not in there right now. And that's the problem, if you will, from my perspective.

And so, Jamie, to your kind of follow up, it seems to me that the potential solutions kind of relate to the underlying cause. But let's just take a simple example

where the operator looked at what came out of day-ahead and vis-a-vis what they thought was likely to happen the next day and said, I'm short reserves. You know, I cannot go into, you know--I don't want to go into tomorrow postured the way I am. And so I'm going to commit X, okay?

Well, you can do a calculation that basically says if I'm committing this unit to provide this much more of a particular kind of reserve--and we can talk about whether it's 10-minute or 30-minute and whatever--you can back-calculate what you were spending per megawatt hour of that kind of reserve. And you can basically say that must be my demand curve for this particular reserve for tomorrow, and you can reflect that.

You know, the RTOs I think are pretty good about putting various kinds of demand curves into their solution solvers, and also their pricing solvers. So that would be an example where you could basically say I took the decision that was made, I'm not second-guessing the operator, the operator committed something that was the equivalent of $350 a megawatt hour for the next blank megawatts of 10-minute reserve. That wasn't in my pricing run. My pricing run's got a demand curve that says I only need 3 percent, and above 3 percent I don't give any credit. And you can modify on a dynamic basis. You can modify the demand curve.

And I don't want to get ahead of the next panel,

but I think PJM is exploring some of these kinds of concepts in sort of a dynamic operating reserve perspective. Dr. Patton alluded this morning in the earlier panel to the fuel setup.

If you've got a constraint that basically said when load exceeds a certain level in Long Island, or in the Manhattan and Lower Hudson Zone, and you need to commit some more oil reserves, you can define that product. You can co-optimize against it in the various pricing algorithms, and you may not eliminate all the uplift. I don't want to portray this as a panacea, but my hypothesis is that these kind of enhancements are easier to graft onto the existing software than some of the more complicated full-constraint relaxation type approaches.

Other people on the next panel may--can agree or disagree with that. And there are people who are more knowledgeable than I am about that. But if that hypothesis is true, this is kind of a good place to expend some effort, see how much you get out of it. See what the residual uplift would be after some of these reserve-based products have been tried.

They may also be amenable to back-cast. You know, that's something that I--an idea I'll throw out for the staff as to whether, you know, whether it's possible for the ISOs or RTOs to go back and look at the data and say if

we had done X, you know, what difference would it have made? I don't know how much effort would be involved in that, but that's another thought that may be worth exploring.

So I don't know if that answered your question, Jamie?

MS. SIMLER: Thank you.

MR. SAUER: Mark.

MR. SMITH: Thanks. I'm just going to take it one step deeper and talk about some actual experiences that we've had in California. Maybe you're aware of these already.

But by decomposing the post day-ahead processes, by saying, okay, what happens after day-ahead, the residual unit commitment, there's one that's associated with the day-ahead, there's one much closer to real-time, and then there's one actually in real-time. By decomposing that algorithm, we can point our fingers to issues that are driving to uplift costs, and probably driving to a persistent price spread between day-ahead and real-time.

The couple of the things that we found that you've already heard about here is that--and the ISO was the one that led the effort on this--was they needed ramping capability. They foresaw a very, very different dynamic because of the secular changes that are occurring in California, moving from gas to renewables.

They saw enormous ramps, you know, to the tune of 12,000 to 15,000 over a 3-hour period. And they said, our normal operating reserves, and our normal energy market clearing function will not position the system in a way that it can meet reliably that ramp. So we need a new product.

And they have engaged this thing they call the "Flexible Ramping Product," which hopefully will come to you in the next six months maybe, that will have some form of opportunity cost payment, potentially different incremental payments as well. So if they hold me back, even though I'm economic to be run, I'll be compensated for that.

The second is this replacement that you may have heard about for the MOCs, the Minimum Online Commitment Constraints. Those are the system operating limits, the N minus 1 minus 1, sort of these deeper contingencies.

And in a similar fashion, the ISO has said let's try to develop a reserve product for that. So the generators who are positioned in a way to meet that 30-minute response would be compensated for any lost opportunity plus potentially some capacity component of that, as well.

So this concept of developing reserves to meet the needs of the things that the ISO does after the day-ahead closes is something that can be replicated out into the future, all the way down, if necessary, to the point of

having a nodal reserves market where individual units or locations, if they needed for voltage support, can be used to meet that need.

So, Jamie, that kind of takes the concept that was described here and breaks it very down into an operational example. And I think those sorts of things are translatable to other markets as well.

MR. SAUER: Let's turn to volatility, if you don't mind. One thing we'd like to hear about, and certainly one of the observations in the staff paper is that uplift seemed to be somewhat volatile. And certainly we've heard from Elizabeth and others about kind of these aberrations in large events and we'd like to learn a little bit more about how volatile uplift charges are, and how market participants deal with that.

Is it something where market participants try to project whether uplift is going to be really high on one day and kind of step back and say I can't manage this, and pull out of the market on that day?

Or are there real mechanisms to hedge uplift that market participants can essentially ride through volatile times?

MR. ALLEN: Volatility does matter, volatility of uplift charges. I think it depends, though, how it works in different markets. The amount that volatility matters is

different.

I think going back to MISO's market, MISO has an hourly RSV or uplift. Other markets have a daily rate. So in the MISO market with an hourly rate, it's actually--this seems counter-intuitive, and with the stricter following of cost-causation principles, even though--and there's a potential for just as much volatility, it's easier for market participants in our sector to handle that type of volatility, because if you're assigned--you get charged a large rate because you caused it.

I think where it's not something that's sustainable is where there's high volatility that you didn't have anything to do with, and you get charged those rates. And what it ends up doing in those markets, in those situations, you know, as I spoke to earlier, the purpose of what we do is to converge the day-ahead and the real-time and thereby lower uplift.

So we need sort of an allocation, whether it's high allocation or whether it's a highly volatile allocation that's not--you know, that you did not cause--it drives a wedge. It drives a wedge between the day-ahead and the real-time. And it's not just what the absolute average of the fee is, but it's expectation of the fee and the possibility of higher fees and the risk premium that you build in. So it creates a wedge between day-ahead and real-

time.

But the volatility can be--like I said earlier, volatility can be stomached if you know that you caused it. Otherwise, you're not going to participate in the markets, which is going to lead to higher uplift.

So, anyway, that's my thoughts.

MR. SAUER: Elizabeth.

MS. WHITTLE: I think I mentioned this at least once before, but for retail LSEs they provide a risk-managed hedged fixed-price product to customers. Customers benefit from the certainty in the pricing.

There's a lot that goes into putting together the price. I don't know all of the components, but I do know that uplift is one of them. And I think that's where there's a lot of risk because uplift is not hedgeable. It's not a liquid market. There aren't buyers or sellers. There's just nothing to do about it.

And we're not saying that uplift will ever go away, but when there is significant volatility it's bad for customers because either retail LSEs are building higher premiums than maybe would be necessary without the high uplift, or maybe there aren't as many participants in these markets able to provide these sorts of products.

So to us the volatility is critical in trying to manage that and put together a product that our customers

can benefit from. So we see a lot of effects of that and hope that through time that the volatility will decrease and the markets will stabilize.

MR. KIMBALL: So in ConEdison service territory we have a very robust retail choice market, about 46 percent of our customers are with retail suppliers, and another 15 percent are with the New York Power Authority. So ConEdison actually supplies about 39 percent of our customers.

And as Elizabeth mentioned earlier, we don't have to worry as much about the pass-through of the uplift costs, but we do have a responsibility to manage the volatility for customers as a retail supplier for those customers.

And, you know, the way we look at it is that the uplift charges and the volatility associated with that is really dependent on the uncertainty in the market. So a lot of the things that we've talked about, the certainty that the dispatch, the day-ahead dispatch, has in terms of determining what resources to commit is defined by a forecast of the demand and what you need to meet that.

And so it necessarily defines pretty clearly what your expectation is going in. And then in that gap between the day-ahead and the real-time, we have a bunch of factors that happen.

And so I think that for ConEdison, we are comfortable that there's a sufficient amount of certainty in

terms of the changes that are incorporated in that difference that retail suppliers are comfortable with being able to figure out how to price in that variation, and I guess for our service territory it's for a lot of the large customers. So they're factoring that premium, risk factor, uplift charge into the fixed-price service that they're providing to those customers.

MR. SAUER: Michael, then Brian, then John, I wasn't sure if you--okay.

MR. SCHNITZER: Thank you. And I'll be brief. But it's the same broken record. I mean, there's no question that the uplift is volatile, as the staff paper observed. But the question is what to do about that, right? And that volatility can be difficult for retail folks to hedge, et cetera. But it is a fact.

So I think it would be--it would not be a good idea to have a policy goal just to diminish the volatility of uplift by smoothing it over larger time intervals, or things like that. I think that just wouldn't make any sense.

I think again the first priority ought to be, you know, to reduce what's in the uplift bucket and put it in the pricing bucket where there are hedging mechanisms available for folks.

So, you know, I just wanted to put again that

volatility conversation in the same--in the same context. Thank you.

MR. FORSHAW: I'm going to refrain from explaining how we manage uplift for like the third or fourth time now. But I would make the observation that if you're really trying to unpack the volatility associated with uplift, there's sort of two components you have to look at.

One of them is the difference between the price of the unit that's actually running and what the LMPs are, what the market prices are. And that's really going to track your underlying commodity costs--primarily the cost of gas or oil.

The other component though is the volume. How many meawatt hours of units are running on a merit. And when you put those together, that's what will really drive the volatility.

So I think it's important if you're going to really look at the volatility question to look at, you know, both aspects of it. How much of it comes from just changes in the underlying commodity costs, and how much of it comes from the actual amount of resources that are running that aren't in the money.

MR. ROHRBACH: Thank you. Mr. Schnitzer, again I just--well, before I get to that--is correct. It is volatile. In my slides on page 12, just one example of

uplift buckets, of an uplift bucket, which is reliability based BOR.

The average month in PJM from January 10 to--so the average of January in 2010, 2011, 2012, 2013, was $10.2 million a month for BOR for reliability. It went up to $389 million, if I can read the small print, it's $386 million roughly, goes up to $400 million in January 2014.

So it is volatile. That is assigned to real-time load. The question is, as Mr. Schnitzer puts it, is what can we do about it? And I think just generally cooperatives are for the most part, we have resources and loads. We're on both sides of this. And I think in some sense we're suspicious of if we want to run everything to LMP into the--and LMP constrained, or a co-optimization formula, or something and--or the Capacity market.

We're suspicious to some degree that you still won't have uplift for reasons that to some extent span, or are beyond the forces here. For example, and I'm going to--this is going to cause me some ire, I'm sure, but Dr. Bowring this morning mentioned that--a generator's choice of a fuel contract for a--or whoever, a marketer or they sign up or the decision about fuel firm transport for example, or--I'm reading into it--but firm transport or fuel market, or that they choose to sign up with to provide their gas and fuel, sort of intimated that it was--and I'll give

him a chance to respond--is that that can drive the degree to which there is or not inflexibility in an area of the grid that leads to the creation of uplift because the RTO has to reflect the minimum run time that is perhaps longer than the RTO wants the unit for.

And it's just my observation that that is as much--that is an artifact of the gas industry. The pipelines have tariffs. They have to manage their grid, too, so to speak. And it's not necessarily clear to me that there's off-the-shelf packages available to remedy that that are not--we haven't really seen them yet.

And so there's some innovation that may have to occur before we can get to that point. Thank you.

(Pause.)

MR. SAUER: I may regret this question, but we'll see.

(Laughter.)

MR. SAUER: Are there--I guess I'm wondering if there are certain entities or types of resources that may be disproportionately impacted by allocation practices, be it physical or financial? So part of it may be--I guess part of what I'm thinking of is: Is there one resource, or a particular resource that typically will have deviations from the day-ahead schedule? And granted those scheduling practices are different across the RTOs. That may be

disproportionally impacted? Or is everybody pretty fairly impacted?

(Laughter.)

MR. ALLEN: Why is everybody looking at me?

(Laughter.)

MR. ALLEN: So, yeah, you know I was, for lack of a better word, I was a little amused when this panel first started before lunch. Some people were talking about how uplift, you know the percentage of, you know, total cost of energy is relatively small, and I'm sitting here thinking, wow, you know, that must be a nice chair to sit in.

Because as a percentage of a company that transacts virtually, it's huge. There's just no other way around it. And not to repeat some of the things I've said already, but in PJM if you're trading INCs and DECs, you know, the average profit margin--this isn't, you know, data, this is data that's provided by PJM, 52 cents a megawatt.

Now 52 cents a megawatt's a lot of money, don't get me wrong, but when you take out the allocation of uplift at $3.38, you're under water. So that's why you've seen, if you check on our meeting materials, you'll see the precipitous decline in virtual activity in PJM.

And the only reason why you have any sort of INC/DEC volume in PJM at this point is because we're fortunate enough that within their footprint is PJM West,

which is, for those of you who don't know or wouldn't know, that's where all the forward futures contracts transact, the ICE contracts.

So there's people liquidating their forward positions in PJM West. Is there nodal INCing and DECing in PJM? There's not. There's not. How can there be? I mean, if you're still in business you're not. How about that?

So, yes, it does have a profound impact. I mean, we operate, you know, on very slim margins. You know, getting back to the UTC transaction, or as we like to refer to it the daily FTR, the analysis shows the gross margin is 32 cents a megawatt.

After you take out the fees that are already paid, now you're down to 27, 28 cents. And if you think you can allocate, you know, an average of $3.38 to it and still have it exist in your market, you know, it can't happen.

And then you have to look at--you know, and that's why earlier I talked about the Woloch study and the value of the products in the market.

And not all deviations are created equal. I mean, there's energy deviations. Obviously that's one thing. You know, if you're injecting virtually or withdrawing virtually, that's an energy deviation and that should pay a higher rate. But if you're net flat, that's why so many markets net. That's why MISO nets. That's why

CAISO nets. That's why ERCOT nets.

So, yeah, it has a profound impact. And, you know, read my bio. It says we transact in PJM. That was true when I wrote it. It's not true anymore. So, yeah.

MR. SAUER: If there are no others, let's move on to a different topic and we'll talk about transparency.

So there are a couple of different ways you can think about transparency. One is market pricing, through market price. And the other is through data.

We've talked a fair amount about market pricing. Let's focus just solely on data transparency. Part of what we'd like to hear is (a) is there enough data transparency out there, be it long term or short term data transparency? And can be done to improve it?

(Pause.)

Wesley, then Brian.

MR. ALLEN: All right, I don't want to monopolize this so I'll keep it brief. I think one of the great things that we see in the MISO footprint that probably needs to be mentioned is whenever they commit a unit that's going to contribute to uplift, it's flagged.

You know, why was that unit cut on? Was it for a Capacity issue? Was it a transmission constraint? Was it local voltage?

So they flag the reason for the commitment of a

resource that may contribute to uplift. That's great transparency. So market participants know--you may not have your DDC rate or your CMC rate at that point, but it gives you an idea of what it could potentially be on that given day. And it's something I would highly recommend for all the other ISOs.

The data is there. You know why you started it. Just flag it and make that information available to market participants. That's probably the biggest suggestion I would make. MISO does a great job.

MR. FORSHAW: You know, there's a lot of data out there. There's a lot of data you can get at. Sometimes the challenge is trying to step back and think about how to put it all together. You know, there probably is additional information. We heard about it from PJM this morning, where there are some chronic, symptomatic problems on the system, relaxing some of the information policy constraints may be helpful, I don't know.

I'm not sure data in and of itself, or greater transparency is going to solve the problem without more structural reforms. But more information helps. The challenge is really going to be for people to work together to think about things: How do we pull it together? How do we unpack things and repack them together in order to provide some meaningful insights?

That was what I challenged myself to do, getting prepared to come up here, and it really did require thinking about things differently. So thank you for that. If nothing else, thank you for that that helped my insight.

MR. SAUER: You're welcome.

(Laughter.)

MR. KIMBALL: So I think that the New York-ISO has done a good job over the last couple of years of really increasing the transparency around their uplift commitments. And I'd like to just kind of go back to my initial comments in terms of working through the information--and I know there are confidentiality concerns that a lot of the generators have in terms of that, and frankly that the local TOs would have as well in terms of some different reliability constructs.

So I think it's important that we look at trying to identify the areas that are of large concern for the markets, that we use the information and work through that in the stakeholder process to try and, you know, identify and eliminate the systemic issues.

There's always going to be uncertainty and volatility in the market. Getting that to a manageable place that's sustainable for the long term is I think in everybody's interest in this room.

MR. SAUER: Mark, then Elizabeth.

MR. SMITH: Thanks. I agree with everybody that just more data isn't really helpful. What I think that would be helpful would be a daily reporting of the uplift. I mean, often people only find out about what the uplift is when it shows up in their settlement statements, either 5 or 30 or, depending on where it is, days later.

So a daily reporting of uplift, broken down by the drivers. In other words, what caused this uplift? Was it units a minimum load? Was it under-recovery of start-up costs? Was it multi-interval dispatch?

You know, what are the drivers that are causing it? And if we could get to that level, maybe that's a nirvana of uplift, if there is such a thing, but if we could get to that level, then, you know, we have information and can have reasoned debate around how to solve them, or how to roll those into prices.

MR. SAUER: I think nirvana would be none, but...

(Laughter.)

MS. WHITTLE: For RESA, I think the reasons why are really important. I hadn't though about a daily report, but certainly understanding why, what caused, how long it's going to be in place, or if it's a permanent or a longer term issue, or a shorter term issue. Knowing that kind of information would go a long way to allowing retail LSEs to manage their products.

And so I think--I don't think we need the, you know, the generator-specific kind of data. We're not asking for anything like that. But we do need to know why, when, for how long, at least a best-guess. Sometimes the answer might be "we don't know," but then if you don't know, please find out. Because we need to figure out, if we have a long-term commitment to a customer, or we're about to sign up a new customer and we're going to have to live with whatever pricing we come up with for one year, two years, three years, we need the certainty at the time so that we can come up with the best product and so that they can, the customer can rely on the best product and the market will function more efficiently.

Thank you.

MR. SCHNITZER: I don't know if this falls strictly in the volatility/more information category or not, but if we again just focus on the post-day-ahead supplemental commitment, a necessary step of doing anything about that problem will be having some transparency somewhere, with FERC, with market participants, about what were the reasons for that? Was it, you know, was it a 10-minute reserve? Was it a 30-minute reserve? Was it a ramping capability? Was it market-wide? Was it for a sub-region? Because you won't be able to identify kind of what the products that you might internalize in the pricing

algorithm are until you have some more transparency about right now the dispatch log says "conservative operations." That isn't going to help you.

You know, you're going to need to dig to the next level of what kind of--what the driver was--not disputing and not quarreling with the operator's decision--but we're going to need something that's a much more granular description of what motivated that action to be able to pursue some of the options that we've been talking about.

CHAIRMAN LaFLEUR: I have nothing at this point.

MR. SAUER: David?

MR. PATTON: I think there may have been some confusion that I just wanted to maybe clear up. It is sometimes the case that when operators are committing things after the day-ahead it's because there's some requirement that wasn't modeled, and I think that's what Michael Schnitzer's getting at, but I only heard one person really talking about uplift allocation and the importance of it.

It may have come across as somewhat self-interested, but--

(Laughter.)

Mr. Paulsen. --let me say that it's of paramount importance. Oftentimes the reason why we're committing after the day-ahead market is not because there's some

requirement that wasn't modeled. It's because the day-ahead market didn't function properly and procure what we needed in real-time. And why did that happen?

Well, maybe we had a load pocket where we could have--where we're seeing congestion in real-time and the congestion is not showing up in day-ahead. If it did, we would commit resources there and we would reduce our uplift. Well why aren't we?

The market response to buy more in that load pocket is getting dinged with allocation charges, uplift allocation charges, when they're actually helping us. It's completely perverse, which is why cost causation I think, if there's one thing that, you know, one simple thing that the Commission could do, it would be to ask all the RTOs to look at whether their uplift allocation rules are consistent with cost causation?

Because I think MISO is the only one I'm aware of that--and New York, to a lesser extent--that's really gone down this road of evaluating what deviations are causing us uplift, what are not, what are actually helping us, and trying to allocate cost consistent with that.

Because if you do that, it will increase the ability of the day-ahead market to produce a commitment that will greatly reduce the things the operators have to do after the day-ahead market.

MR. SAUER: Thank you all. And with that, let's take a ten-minute break and convene with the third panel shortly.

(Whereupon, a recess was taken.)

MR. SAUER: We'll ask everybody to sit down and we'll begin the panel in just a couple of minutes.

(Pause.)

Okay, well welcome back everybody. This panel is going to be quite, or I hope at least will be quite interesting, in that we've spent a lot of time talking about the impacts of uplift and the drivers, as well, and this is really the I guess next steps is probably the best way to put it. We'll hear some from the RTOs in particular about some of the steps that they've already taken to minimize uplift and whether there are pros and cons with the approaches that they'd like to share, and considerations for us and other RTOs in fact to think about.

And after that, we will get into other solutions that haven't been implemented yet that should be thought of, or that should be discussed at least.

It is important to note that we aren't using the solutions that have already been implemented by the RTOs as a proof-of-concept and not something that we're looking at in terms of--and we know that this approach works in PJM, well why isn't MISO doing this, or why isn't California

doing this? It's really a--we're trying to see what the possible solutions are out there and learn more at this point in time.

And with that, let's introduce the panelists so everybody can hear.

Stu, welcome back, from PJM. Bob, welcome back again, New York. Joe, welcome back, Monitoring Analytics. Todd--I'll stop saying "welcome back"--

(Laughter.)

MR. SAUER: As you know, there's a lot of repeats, which is good. Todd Ramey from MISO. Matthew White from ISO-New England. Bill Berg from Exelon. Susan Pope representing EPSA. Brian Forshaw representing CMEEC. Brad Cooper, California. And Richard Dillon from SPP.

Richard may have to leave early to catch a flight, so he's assured me that he's not leaving because of anything that anybody else says--

(Laughter.)

MR. SAUER: --or what I say. So pardon his early exit, and thank you.

Let's turn to MISO first. One thing we'd like to hear about is, so MISO's taken some recent efforts with extended LMP. We would like to hear about how modeling commitment cost as part of the electricity price has gone so far, and whether are are any sort of pros and cons and

considerations that you can share.

So thank you very much for your time, and after you're done we'll turn it over to some of the other panelists to ask questions or respond to your brief summary.

MR. RAMEY: Okay. Thanks, Will.

ELMP, it was probably six years, or a few years ago or so, we started engaging our stakeholders in a conversation about potential ways to improve price formation calculation of market prices with an eye towards potentially having a benefit of reducing uplift payments.

That led to a series of studies, development efforts, years of conversations with stakeholders around the concept of implementing a convex hull type pricing, which essentially is intended to bring in some of those nonconvexities into your pricing algorithm so that what was previously considered a limitation of LMP-based pricing, which was only being triggered and driven by energy components of resources once they were committed, is there a way to improve the algorithm?

In concept and in theory the algorithm itself could be implemented in a variety of ways initially looking at full convex hull type pricing, with an option. Through conversations with our stakeholders, a decision was made to initially proceed with a much more simplified version of convex hull pricing, really kind of an estimated, extended

Locational Marginal Pricing, and that's what we developed and filed and was approved by the Commission.

Earlier this year we implemented a parallel operation phase of the new pricing algorithm for day-ahead and real-time. We ran ELMP pricing in parallel with the current LMP pricing, which is still used for settlement purposes.

We ran ELMP in parallel for the months of April, May, and June. A couple of objectives of that parallel operation, one was just to validate the ELMP algorithm. Was it performing as intended per the design?

We did learn that, yes, it is performing as it was intended. There were a couple of aspects to it. One aspect was to bring in some startup and no-load cost information into price participation for certain resources that are committed in real-time.

There was another piece of it that allows offline resources that were not committed in certain situations to also participate in price setting.

Given the mild summer that we experienced and the narrow implementation of our ELMP algorithm in terms of which units were allowed to participate in price setting once committed, it was limited to fast-start resources with a start-up time of less than 10 minutes. And those units also had to have a minimum run time of no more than one

hour. So it's pretty limited in its application.

And just given the nature of the cool summer we had, we really didn't have a lot of opportunity where we were committing these fast-start units in real-time. So we didn't have a lot of opportunity during our parallel operations phase to have a lot of observations of ELMP impact of committing fast-start units.

We did have some, though, we we were able to validate that the algorithm worked pretty well. And it works as advertised. So--maybe I should say "worked as designed." So the way it was designed was that essentially it includes the start-up and no-load costs of the resource that's committed in real-time across that hour of the commitment period.

So it did have an impact on pricing, and in those circumstances where these types of resources were committed we did see LMP setting prices higher than the equivalent LMP during the period.

There were lots more opportunities where ELMP, with its feature of pulling on units that did not get committed that are available to participate in price setting, we did see several instances where that occurred as well.

Essentially with our LMP application and our co-optimization of energy and ancillaries, you can have

limited periods of time where you may have a 5- or 10-minute period where you have ramp constraints on the system, you are deficient of your required operating reserves for that 5- or 10-minute interval.

Pricing in that case goes to an LMP scarcity pricing curve. So it's not uncommon from time to time to see significant price jumps in LMP driven by those transient scarcity conditions. And these prices can go from $50 one interval into a transient scarcity condition where you may have $300 or $400 prices for the next interval. Then you're back down to $50.

ELMP is proving very effective at being able to mitigate those scarcity conditions. So we actually saw higher impacts during this period where the resulting ELMP was actually lower than the average LMPs.

So it worked as designed. Other observations that we had from the trial is that the reduction of those price spikes, 5 or 10 minutes in duration, actually reduces real-time price volatility. Real-time price volatility as it increases tends to increase the uplift associated with those price volatility make-whole payments.

So on net, during our period we had ELMPs that were on average lower than LMPs, but even still we had a net total reduction of total uplift across that period because ELMP had a significant impact on reducing those price

volatility make-whole payment uplifts.

So that's kind of where we're at. Dr. Patton has observed the parallel operations phases and quite a bit of analysis, shared some observations with MISO and our stakeholders, which we have evaluated as well. We think there are some opportunities to improve on the design a little bit, make some tweaks primarily around those units that are off-line and participating in price setting.

So that's my ELMP five-minute overview for now.

MR. SAUER: Thank you, Todd. Do any other RTOs have anything similar? I'm thinking in pretty broad terms here. Or do you have any other thoughts to share?

Bob?

MR. PIKE: So New York has employed what we refer to as a "Hybrid Dispatch" and it allows the capability for gas turbines, which are essentially a fixed block unit in our design--they're on/off at a single output level.

In 2001 we implemented changes to allow those resources to participate in the price setting, really under the idea that we were calling upon those resources. So we were clearly into a need for that type of resource to be operating on the system, but in the original design they didn't set price. So we would still have very low prices occurring on the system, inconsistent with the needs that we were seeing at that point in time.

So we went ahead and implemented that design in 2001 that allows them to set price. It essentially runs a first dispatch test to see if the resources are needed to meet transmission reliability constraints. And then as long as they are, it includes them in a process of setting prices.

After our SMD-2 implementation in 2005, we also added what we call off-line GT pricing. It's resources that are capable of starting on 10 minutes but haven't been given a turn-on signal yet, but we still include them in the dispatch with an amortized start-up cost over the hour to let them participate in that process.

They tend to generate very high costs, if we're going to those resources, and essentially it's saying we should be turning to those resources. We should be expecting the real-time commitment tools to be bringing those resources on very shortly because the dispatch tools are saying they are the economic resource to move to.

MR. BRESLER: This is Stu Bresler, PJM.

Just to pile on that a little bit--and I'm not going to remember the exact date when we made this change--but PJM does something very similar to what Rob just described with respect to the on-line combustion turbines where, if the combustion turbine is needed to maintain power balance respecting transmission constraints, the program

will actually drop the minimum, the economic minimum if you will, on the combustion turbine in order to make it flexible and allow it to set price.

So we have included on-line combustion turbines even if they are not flexible in and of themselves to be flexible in the price-setting algorithm, again to the extent that they are determined to be necessary to maintain power balance and manage transmission constraints.

So we do have CT setting price in PJM. We have not gone as far as Rob described in the second part there as allowing off-line units to set price as far as the real-time LMP is concerned.

So the real-time security constrained economic dispatch algorithm is limited to utilize only that which is on-line and therefore able to be dispatched. We have our look-ahead tool, which we call our intermediate term security constrained economic dispatch tool, which does that short-term unit commitment for 15 minutes up to about 2 hours out into the future for those short-term units.

MR. WHITE: Good afternoon, Commission staff and Commissioners, it's a pleasure to be here.

Two points on both Todd and Stu's previous comments. Our fast-start pricing logic is much more similar to what PJM has than what Midcontinent-ISO has. Essentially we will relax the minimum constraint on fast-start units

during the start-up phase, which can enable them to set price for a time, however.

But to ensure that what the dispatch does is fully consistent with the pricing algorithm, the pricing then respects the minimum output for most of the time when a fast-start will be running.

We think that consistency is important to assure that resources have proper incentives to follow the dispatch.

Relating this back to the convex hull, Bill and I, just before we sat down, were sitting around and I think he read my mind, because when people talk about convex hull pricing, we both thought, well, if you get seven people who do ISO stuff for a living and you ask them what they're talking about convex hull, talking about convex hull you spend the first 25 minutes trying to figure out if you're all talking about the same thing or not.

Todd noted that they have a, I think you used the word "simplified implementation" of the original pricing. There are many different simplified implementations, and they have very different properties.

We have looked into some of these, and to the theme of today's conference I think it's important to point out it's by no means clear that uplift goes down under most simplified implementations of convex hull pricing, or even

under the original sort of full-blown version of convex hull pricing relative to what ISOs do today.

In particular, for example when we've looked at some of these implementations, one potential concern is that by allowing--essentially relaxing minimum run--minimum upper level constraints, which is essentially what the simplified implementations tend to do, you create a discrepancy between the assumptions that are used in the dispatch, which enforces the minimum output, because that's a physical constraint on the resource, and the assumption that's used in pricing which is relaxing it.

When you get that discrepancy, there are situations where the other resources may not want to follow the dispatch. You can prevent that, but you need to start introducing new things like expanded lost-opportunity cost payments.

We have very little lost-opportunity cost payments in New England. It is entirely possible but largely speculative at this point since we don't have this pricing algorithm, that those payments could go up. So one could easily end up with higher, or possibly lower uplift payments using some of these different implementation schemes.

The challenge really is, these questions have no clean theoretical answers. You have to essentially build it

and run it and test it and see.

Now to that point, we actually greatly appreciate all the work MISO has done I think on everyone's behalf to start to look into this, but I would caution against a rush to judgment on any of this. Because as Todd--and I appreciate his point--pointed out, this as you all know is a relatively cool summer. Not all of the situations that one might want to see repeated to know what its effects are have played out in the data that are available for all of us to look at courtesy of Midcontinent-ISO right now.

So time will hope to answer many of these questions, but these are complicated issues that can have unintended consequences unless we fully understand how they work, because the answers aren't clear based on pen and paperwork alone.

And so we look forward to understanding more about how these work, but we see a lot of those tradeoffs as not giving clear answers, given the best available information at this time on whether these kinds of pricing innovations will at the end of the day actually reduce uplift relative to what happens today.

Thank you.

MR. SAUER: I think you were first, Brad, and then Susan.

MR. COOPER: So every year we do a process to

rank potential initiatives with our market participants and Extended LMP ranked fairly high, particularly among generators, though we've decided to defer looking at that for a couple of reasons.

Like Matt indicated over here, we wanted to see how it played out with other ISOs. And from what we understood from the Midwest ISO, it took a real long time to develop it. And, you know, given your big market changes, you know, we have the Energy Imbalance market, and several other big market design changes going on, we wanted to wait till we get all that done.

You know, we went for resource--to address resource constraints, and then, too, just to not be making too many changes at once, to let things settle out.

We do have a more limited version of allowing minimum-load cost to set prices. It's only applicable to generators where the minimum output level is very close to the maximum output level, but it's used for very few generators. But in that case, the minimum-load cost can set the LMP.

MR. SAUER: Susan?

MS. POPE: Yes. Thank you for the opportunity to talk here today. I just wanted--I participated a little in the development of the original convex hull for the MISO, and I just wanted to clarify a few things.

One is that the pure convex hull theory, the ELMP theory, is uplift-minimizing, taking into account any additional uplift of the make-whole payment variety that you might have as a result of implementing the changes in prices due to convex hull everywhere.

So the pure--the pure convex hull is designed to be uplift-minimizing. That being said, I agree that what has been implemented in different places are all approximations and simplifications in different ways to that sort of pure form of the convex hull pricing.

And that being said, I do agree that there can be unintended consequences as you work through the specific rules of how to do that.

However I did want to just, you know, return to what Rob said, which is that the New York-ISO has been doing this for quite a long period of time. So there is quite a long period of experience with what they have done with their form of hybrid pricing. And their particular form just takes into account GTs, the block-loaded GTs, in price formation.

It explicitly doesn't take into account one of the other pieces, which I think a lot of parties have talked about with sort of expanded forms of convex hull, which is taking into account the costs of minimum load blocks and minimum run times of some of the longer-start

resources.

So that is not done in New York, and as far as I know that's not part of any of the other simplifications. So that's quite a big simplification right there in going from trying to include the minimum run times, the minimum load blocks, in some form of an expanded pricing scheme to looking at well let's just improve pricing to include these fixed-block GTs, or demand-response that's used for example in Midwest-ISO, when these things are there and they're needed to serve load.

So the only other thing I just wanted to add is I think there's a real need to try to get more of an apples-to-apples comparison of the different implementations of the simplified versions of convex hull or ELMP, whatever you want to call it, hybrid pricing, that the different ISOs are doing.

You know, I tried to get some of this information, and thanks to many of you who have answered my questions, but some of them only apply in certain situations when certain constraints are binding. Some of them only apply to certain kinds of units, to only allow units to participate that have certain characteristics. Some have parameters that can be set in them so they will only apply to say a certain percentage of the upward block of a unit. All of these things have a great deal of effect on the

extent to which the simplified implementations can actually reform pricing.

And I think we need to--there's a need for improved understanding of why the different ISOs have adopted the different approaches, the different simplified approaches, that they have adopted, and the pros and cons of those. And I think some of it there may be very good contextual reasons for in the ISOs, but I think we need to understand that better.

MR. BERG: Good afternoon. Thank you for the opportunity to be here today.

Picking up on what Susan said, this extended LMP/convex hull, it is a very complex issue. The goal is simple. We're trying to minimize uplift. But the details, the algorithm and how it's set up very much make a difference.

Long-leadtime units--I put an example in my prefiled testimony where--and I think this happens often--you have a unit that has a 6-hour minimum run time. It's needed for an hour or two of that 6-hour minimum run time, and it's paid uplift for the remaining hours.

And I think it is a fair question to ask ourselves: Well when that unit is actually needed, is its variable cost, the cost of the next megawatt hour, actually the appropriate price?

And it leads to, if you follow that path and you think about how the system is changing, and you think about I had to commit a unit for six hours when I needed it for one, it created a lot of uplift, it is good for the market, good for technology choices, good on all aspects to reflect the cost of that six-hour minimum run time into the time it's needed.

That being said, I think the starting point really is to see what's out there in the different RTOs. Look at the pros and cons, and really get into the details.

And jumping ahead a little bit here, there's two paths to this equation. One is what should the marginal price be when the marginal unit is actually marginal. And the second is what Dr. Patton brought up earlier, and I also put this in my paper, is do the reliability requirements match the market requirements?

You can have the best convex hull system in the world, but if you do not reflect the fact there's conservative operations in a system that's swimming in generation, that unit's never going to be marginal anyways.

So it's both pieces of the equation I think we need to take a look at.

MR. SAUER: Going with an analogy I think we

heard earlier, I think it was Richard who said it, I think we've touched the very tip of the iceberg here and ELMP is a very big, weighty topic, but thank you very much for the preview. We will try to move on to other topics so we can try to get through this panel without talking about anything other than ELMP, because I think we could, easily.

(Laughter.)

MR. SAUER: There's another solution that I'd like to highlight that has been implemented--or that really all RTOs have approached this, to my knowledge, in some way or another and it's really taking difficult-to-model constraints and incorporating them in the model one way or another.

I'll try to get to a couple of examples. Depending on time, it may only be one. First I'd like to turn to PJM and talk--or hear specifically about their closed-loop interfaces, which is from my understanding turning an reactive constraint into a thermal constraint. There's a lot more detail to it than that, and thank you, Stu.

MR. BRESLER: Sure, Will. So as I said on the panel this morning, I think all system operators have at least some experience with dealing with reactive and voltage problems on their system, and probably for a long, long time now have translated those problems--those reactive and

voltage issues into thermal constraints that can actually be modeled in security-constrained unit commitment economic dispatch and locational pricing schemes.

As I said earlier, PJM has been doing so with 500 kV transfer constraints for a long, long time. So also for several years now we have been looking, when necessary, when we have a localized voltage issue like a low voltage condition in a relatively small segment of the PJM system, what's been referred to as a "load pocket" again earlier in this conversation today, to build an interface, if you will, that represents that area of the system that is constrained by that voltage condition. And again, typically it's a low voltage condition on a relatively localized area of the system.

The support that provides additional help in a voltage condition like that doesn't travel very well, typically, so you can't run units that are far away in order to help that localized voltage constraint.

So what these constraints typically look like, or these interfaces that we build typically look like, is what we refer to as a "closed-loop interface." Because what it amounts to is a, sort of a cut set of transmission lines that has for all intents and purposes--especially if you forget about losses for a second--one hundred percent distribution factor for any resource inside the interface,

and a zero-percent distribution factor for any resource outside the interface.

What that means is, if you raise the output of a resource inside that closed loop, it will help your voltage problem by exactly 100 percent of the output, but nothing else outside of that circle, if you will, will help the voltage problem.

And we utilize these closed-loop interfaces in order to model the areas that are affected by these localized voltage conditions such that when we turn on generation inside that load pocket where that voltage condition exists, that resource is able to set price because the closed-loop interface constraint that we model will bind in both the dispatch and the pricing algorithm.

It does get tricky in several ways, or complicated--complex, I guess to use a better word, to establish what the limit, what the flow limit on that closed-loop interface needs to be.

Because many system conditions tend to have an impact on whether or not you actually see the low-voltage condition or not on any given day, or during any different period in the day. The primary driver or drivers, I would say, is probably the load level within that load pocket and the transmission topology that you have available to you.

So it gets difficult to predict when during an

operating day that voltage condition will actually occur because you can't exactly predict what the load will be when, and other system conditions like transmission flows through the load pocket and those things, sorts of things that can also impact whether or not you'll see the voltage condition.

So modeling in real-time is not all that difficult because you actually see the voltage problem occur. You put the closed-loop interface in your real-time dispatch and pricing algorithms. The unit gets turned on, and it can set price.

In a day-ahead sense, it becomes trickier in order to know what flow limit you should put on that constraint so that you actually see that voltage limit bind in your day-ahead market under the exact same conditions you'll see it bind in your real-time market. So alignment between day-ahead and real-time can get tricky in those instances.

The other downside that I'll mention, as well, is these localized voltage problems can come and go on the system because of various conditions like outage conditions, for example, that can cause them to be there for short durations but not be there for the vast majority of the time.

And so predicting them far enough ahead of time

to get them into your transmission right models can become very, very difficult. And so what can happen in certain instances when these closed-loop interface constraints are utilized in order to appropriately reflect what is operating to maintain transmission reliability in day-ahead and real-time price, is we can see FTR revenue inadequacy. In PJM we call them FTR--sorry, Chairman LaFleur--Financial Transmission Rights. They're called transmission congestion contracts, and other things in other markets as well.

But to the extent that they are not modeled in your transmission right options, or your allocations of transmission rights in your transmission right auctions, if the flow limit that ends up being put on that closed-loop interface in day-ahead and real-time is less than the flow that was allowed in your transmission right auctions, it can lead to revenue inadequacy for transmission rights.

And if they're modeled in real-time only and not day-ahead, then one way of thinking about it is you can end up trading off one form of uplift for another form of uplift, which is what Todd Ramey referred to earlier, I think appropriately, as Negative Balancing Congestion, as another form of uplift on the system.

In PJM, we don't allocate Negative Balancing Congestion as uplift in the sense of what we lump into balancing operating reserves, in PJM parlance; rather, it

goes into the overall Congestion Fund which goes to fund FTRs. When we see Negative Balancing Congestion in PJM, it impacts the funding available for FTRs, and therefore decreases their effectiveness as a hedge against day-ahead price differentials, which is where they're primarily valued.

So that's probably enough detail for this discussion, but those are some of the benefits. Again, price transparency, energy market uplift management if you will, or decrease minimization on the plus side, but there are some consequences to using closed-loop interfaces as well to set prices on the system.

MR. SAUER: We'll do the same thing as last time and turn it over to the rest of the panelists with the question of, for the RTOs, do you do a similar thing? And for everybody else, any other comments to share?

Joe?

MR. BOWRING: So from a slightly different perspective from Stu's, I appreciate the fact, as Stu pointed out, that it's not all good. And I agree that, for example, the 500 kV transfer interfaces have been used successfully in PJM for a long time. In fact, real reactive constraints continue to be used, and used effectively.

They can be used effectively where there's a real megawatt limit into an area, where the limit actually

applies to imports in some of the area. You get into more difficulties when you're setting artificial constraints, what I would call artificial constraints, where PJM has to actually actively modify the constraint, effectively arbitrarily, to get a particular unit to set price, to get the constraint to bind.

It's not actually a physical constraint; it's an attempt to set the price at a level to reflect the reactive need. And that can have, as Stu mentioned, unintended consequences. In fact, it can be very difficult to do. The Seneca Interface is an example of some of the difficulties that can arise when you attempt to do this. It's not at all straightforward once you get away from the clean versions of this.

In addition, PJM has used closed-loop interfaces to specifically let demand side set price. And again, that strikes me as being an inappropriate use of closed-loop interfaces--again, arbitrarily setting up a set of transmission constraints into an area with the intent, with the explicit intent, of having demand side set price.

Demand side could set price if it were nodal; it's not nodal. This is an attempt to adapt for that rather than simply having the R be nodal. The ATS interface in the summer of 2013 is a good example of that.

So there can be--the unintended consequences can

include what Stu mentioned, which is FRT or revenue issues that can affect virtual bidding. It can affect broader zonal prices. And in fact, if you use it to set--for example if you need a unit running at eco-min in order to provide reactive support, the higher LMP that you induce by setting these constraints can affect--provide an incentive to produce more than is economic. In fact, you are then getting a price that really doesn't make much sense and it's not consistent with the way LMP is normally set.

Now just as a final partially relevant comment, I don't regard Negative Balancing Congestion as uplift. Negative Balancing Congestion is part of congestion and I think it's a mistake to include it in this broader discussion of uplift.

Thank you.

MR. SAUER: Brad?

MR. COOPER: As Guillermo mentioned this morning, we've implemented what's known as our Minimum Online Constraints. And it's used for voltage needs, though it doesn't address all the voltage needs; and it's also used for flow-based constraints. And what the Minimum Online Constraints do is, with a defined area it makes sure a certain amount of generation capacity is committed.

Prior to that, we just at first we did that with exceptional dispatches, and then we committed--after that,

we quit using exceptional dispatches; then we committed additional generation in the residual unit commitment process. And those both had the disadvantage then that we're flooding the market with too much energy and suppressing prices.

So the Minimum Online Constraint assures a sufficient amount of capacity is on, but it has the advantage that then it's incorporated into the market. And so the remaining energy from those units can potentially clear the market and often does, and it avoids adding too much excess energy.

When we implemented that, it had a huge impact on exceptional dispatches--or exceptional dispatch energy went from an average of 3- to 400 megawatts in 2009 per hour, to average 50 megawatts in 2010. So it substantially reduced the exceptional dispatches.

MR. SAUER: Todd.

MR. RAMEY: Yes, in MISO we certainly have experienced trying to use similar thermal-type constraints to resolve voltage issues. In fact, we may have attempted to use such an approach to solve voltage problems in the Cleveland area at some point in the past.

(Laughter.)

MR. RAMEY: What we found was that--and it's been mentioned here a few times--that certain thermal, or voltage

situations lend themselves well to being modeled with a thermal constraint, and others just do not lend themselves well to that type of solution.

In MISO, given the potential problems of trying to implement a thermal constraint type solution for a voltage situation that doesn't lend itself to that type of solution, only in the real-time has the potential to create these ripple effects in upstream markets, including real-time balancing congestion issues as mentioned, even FTR funding issues.

So in MISO we've simply abandoned that approach. If we can't use the thermal proxy to get a desirable unit commitment outcome in the day-ahead market, we won't implement it only in the real-time market as a result.

So what that means for us, we may have some manual commitment decisions that are made in order to support local voltage that's probably going to drive some level of uplift. But even in that case, we try to get those commitments in the day-ahead market so that we can just optimize the commitments around it as best we can.

MR. SAUER: Let me make sure I have that right. So if you can't get the ideal constraint, thermal constraint for that, you won't model in the day-ahead; it'll just be in the real-time and you might have some--

MR. RAMEY: No. If we're not able to replicate

the constraint so that it successfully produces the desired outcome in the day-ahead market, we will not implement it in either market.

MR. SAUER: Matt.

MR. WHITE: Thank you. We also have experience attempting to model primarily low-voltage constraints as what I'll call real-power constraints, sometimes called thermal-constraints. We do it on a limited basis when we think it will actually work and do the right things.

And a very cognizant point Joe Bowring made early this morning that I felt went by very quickly, there are times when it's not at all clear that it would work, and it probably is better not to try than to do something willy nilly and hope that it will work.

Where we--modeling the constraint, however, doesn't really solve the pricing issues that many of your early questions focused on. I think it's important to make sure the logic for that is clear.

Pete Brandien in this morning's panel mentioned that in the western Massachusetts areas we sometimes have low-voltage concerns, particularly at high load levels. We have a lot of constraints in our day-ahead and real-time market software that attempt to model the reactive power needs through real power requirements.

They work exactly as designed. The relevant

units that are needed for dynamic reactive support get committed during the times when we expect we would need them, and therefore do not need to be supplementally committed.

That doesn't really solve the pricing issue because those units will rarely set the price where they are. They are typically higher cost units; otherwise they would be committed economically without these constraints. They have economic minimum output levels, that mean they have to run at a higher level than would be economic but for the constraints. But once they're committed, they provide more power than is really needed to meet the constraints, more real power, so they don't set price.

In very simple terms, in the day-ahead market pricing stage and in the real-time market, the software says if I have another unit of real power demand at that system I wouldn't use that unit. I'd use some other unit that's cheaper and bring in more power form elsewhere. So the units simply don't set price.

However, they're fully modeled in the system. In essence, the take-away is it isn't that the constraints aren't modeled, or that lack of having the model constraints is the problem, it's back to a more fundamental issue that many people pointed out in the immediately preceding panel which is that when you have inflexible units that are high

cost and they need to run for a number of hours but they're only needed for a limited amount of time, or alternatively they're needed for a different product, a particular reactive power, the system will not see them as the resource they turn to if you're using a pricing system that's based on the fundamental logic that all ISOs have used since our creation, which is price should reflect the marginal cost of real power.

MR. SAUER: Stu?

MR. BRESLER: Since everybody's had an opportunity, I just figured I'd follow up on one or two things.

First of all I wanted to commiserate with Todd a little bit because the Cleveland interface was binding in the PJM dispatch and pricing on Friday. So I feel your pain, Tom.

(Laughter.)

MR. BRESLER: But also I just wanted to--I know we don't want to necessarily turn this into a debate so I'll stay away from anything that's a matter of opinion, if you will, but from the standpoint of what PJM models as far as these constraints are concerned, since Dr. Bowring used the word "arbitrary" in his comments, I wanted to make sure that we were all clear that a localized voltage issue on monitored transmission facilities is no less a physical

problem than a flow overload, a megawatt overload, on a transmission line.

It's a physical issue that needs to be rectified, and I think it's appropriate that the resources that are utilized to rectify that issue are made transparent through the pricing.

So when we establish the megawatt flow at which a constraint binds that we utilize to model one of these localized transmission voltage problems, it's really no different than the megawatt flow limit that we establish for our reactive interface.

That megawatt flow limit is not the sum of the thermal ratings on those lines. So they are not thermally constrained. It is the megawatt flow that the translation program determines above which you will have the voltage problem exist.

So it is really a directly analogous translation of what megawatt flow results in that voltage problem occurring, and we bind that in the algorithms on the pricing. So I just wanted to make sure we all knew what was going on there.

MR. BOWRING: So it's fair to say it's not arbitrary. But it's also not the case that that's the outcome that would result if you were setting the price based on the marginal cost of providing the next unit of

power to meet the thermal constraints. It's a different constraint that will result in a different price outcome than the LMP algorithm, and that's really the point. And it can produce results which are inconsistent with it.

So the question is whether you have--whether you're pricing the reactive product or the energy/thermal product, and whether you can really do those simultaneously. If it were easy, it would have been done a long time ago. There are constraints where it can be done straightforwardly.

I think there are some--and I think PJM has done some recently--where it can't be done straightforwardly and there's been some significant negative consequences. So I think it's worthwhile remembering that this is not--like any of the other solutions, this is not a solution to all the problems. It can be a solution in a narrow set, but it's certainly not a solution for all the issues.

MS. POPE: Just to echo what was said a number of times in the previous panel, I think that a number of people are on the page where they'd like to see prices set consistently with the unit commitment in the dispatch, whether that unit commitment, for example, is purely the result of a model run with no additional commitments based on operator intervention, or whether the unit commitment is the result of a model run that may be a subsequent operator

intervention for something that the model didn't pick up.

Either way, the prices should be set based on what comes out after the operator has finally taken a look at it and said this is my final reliability=based least-cost unit commitment.

Listening to what's going on here, I'm starting--trying to think about these voltage constraints, and these complicated constraints, and I'm kind of seeing a 2 x 2 matrix in my mind here. So I'm thinking you've got one axis which is, well can you capture the constraint in your unit commitment program? Can you actually model it? Is it one of these that you can get a thermal representation of it and you can model it? Or maybe you can't.

And then the other axis is, well whether, leaving aside the first question, can you represent it in your pricing algorithm, or can't you?

So we've got four squares of this. And I'm not sure in some of the discussion which of those blocks we're talking about, okay? So it seems like there--it sounds like there are some types of voltage constraints and difficult type of constraints on the system where not only can you model them possibly in software, but you can also represent them in the pricing algorithm once you've got them in the software.

And then maybe there are some where you can't

price--you can't represent them in the software because that's really, really difficult; but once you know the constraint--once you know the operator committed something because of the constraint that it couldn't model, can't you take the knowledge that the operator did that and represent that constraint in the pricing model?

And some of what I'm hearing here sounds like, well, maybe yes, maybe no, because, what Matt was saying is sometimes once that unit's on, maybe the constraint doesn't bind anymore because it's producing more than it really needed to resolve the constraint.

So it seems like that's a box to work on. You know, the one where maybe we can get it in the pricing algorithm even though we can't model it in the unit commitment. And then, well, the bottom right-hand corner box is pretty much impossible.

But anyway, that's the box that I'm the most interested in. And I guess I'm still looking for some clarity on whether there are additional constraints that would fall into that category, where we might not be able to model in the unit commitment but maybe we can get them into the pricing.

MR. BERG: Just real fast, these closed-loop interfaces or these very detailed technical issues, I think it's important to ask ourselves what constitutes success?

What are we trying to do?

And I believe the goal should be to move uplift, persistent uplift or general market uplift, into the market prices so that we can get--you know, we can get the correct market signals and the responses that follow.

But I believe that's what closed-loop interfaces started with. There were a set of units--and I could be wrong here--but there were a set of units that were consistently needed for this local condition. And absent some action, they were going to show up as uplift. So this is an attempt to do that, which I believe is a good goal, and it brings it back to what constitutes success, what are we trying to do.

MR. BRESLER: Just so that's not hanging out there, yes, that is correct. That's how we started out with these closed-loop interfaces, is we had units running for transmission that we were not getting in the price, and so we utilized these to make that happen.

MR. SAUER: Let's take a step back for a minute and think about broader solutions. So we'd like to hear some concrete examples of both near- and long-term solutions for addressing the drivers for uplift payments.

This could be introduction of new products. It could be getting into modifying pricing rules. It could be the treatment of certain resources with modeling of

constraints. Please think of that as broadly as you want.

And I imagine everybody will have something to say here, so we can start left and go right, if that works, if that works?

MR. DILLON: From my left?

(Laughter.)

MR. DILLON: Good afternoon. Needless to say, we've got our plate full. But even with the plate full, there's a lot of wishes that are out there.

One item I had mentioned earlier in the day was commitment for ramping purposes. And there were two aspects of that. There was having sufficient ramp, which is kind of a closed--no pun intended, a closed-loop type thing, because if you don't have it, then you want it; and if you get too much, then it doesn't have any value.

And one of the items that we are looking at is not a separate product, because we get more products and then you have interactions, but actually looking at giving it a value in the calculation of the LMP, a step value that would have a dual effect of delaying some dispatch of the faster rampers for when you really need the ramp, but also set the price a little bit higher when they're deployed so that the net revenue still comes out the same for those faster rampings even though they're producing less megawatts.

That is a long term product, but we looked at--the tendency is, let's create more products. And then the interplay results in unintended consequences, which also translates into uplift.

So we're looking at items that don't create more products so much as incorporates it into some of the pricing algorithms. We're also taking another hard look at what's necessary for operational purposes versus pricing purposes.

We've had a couple of items where the right thing for a power flow analysis is not the right thing for price, and taking a look at that.

Will that get rid of uplift? Absolutely not. There will always be uplift. But hopefully in zeroing in on some of these items, we can start managing and saying, okay, do we really need to commit 300--which sounds small--300 extra megawatts that we know is going to sit on min, except for when we hit the accelerator, which means it all goes into uplift.

So those are a couple of items that we're looking at.

MR. COOPER: So I guess we're taking a slightly different tack. We're developing a bunch of new products.

(Laughter.)

MR. DILLON: I'm always the outlyer.

(Laughter.)

MR. COOPER: So the first one we're in the midst of is we're calling it Contingency Modeling Enhancements. And this will improve on the MOCs, Minimum Online Constraints. It doesn't address--it doesn't address voltage needs, but what it addresses is the N minus 1 minus 1, the second contingency needs to get back to flow limits within 30 minutes.

And in our view--or we think that this kind of thing is especially important in the West because we're not in the middle of such a meshed network as in the East. You know, we have several long transmission paths. So we have to position units very precisely to be able to manage the flows, you know, should there be a contingency on one of the major transmission paths.

What the Contingency Modeling Enhancement initiative does is, rather than the MOC or Exceptional Dispatches which are kind of--even the Exceptional Dispatches, even though they're dispatching a specific unit, our operators don't have a tool to tell them precisely the impact of the unit on every transmission line.

So what the Contingency Modeling Enhancement does is to develop the software to calculate that. And then we would calculate what's called a Locational Marginal Capacity Price at each node, which the Locational Marginal Capacity Price is the shadow value of positioning the system to meet

that secure state. It's usually either the opportunity cost of holding back a unit to be able to respond, or it can be the cost of limiting flow on a line.

So units that provide this capacity would earn the Locational Marginal Capacity Price, and then it--it will also affect the LMP. For example, we could hold back--potentially hold back capacity from a less expensive fast-ramping generator for the capacity, but then dispatch up a slower, more expensive generator for the energy which would set the energy price.

And then also, besides being a more precise tool than the Minimum Online Constraint, the Minimum Online Constraint has the disadvantage that it just knows it needs a certain amount of capacity in an area. For example, if the precontingency limit is--on a major path is 2,500 megawatts and the post-contingency limit is 1,500 megawatts, the MOC just knows it needs 1,000 megawatts of capacity from somewhere, and it makes sure 1,000 megawatts is set up.

This new Contingency Modeling Enhancements functionality looks at the actual flows. So if the post-contingency limit is 1,500 megawatts but the projected flow is just 2,000 megawatts, then it just knows it needs 500 megawatts of capacity versus the blunt 1,000 megawatts.

And this should further reduce our out-of-market exceptional dispatches. We took a look, in 2012 on a

monthly basis roughly 21 to 77 percent of the exceptional dispatches look like they were to meet post-contingency needs. So that was like $47 million out of $101 million. so those were real rough estimates, but we think it should reduce the cost pretty substantially.

Then the next product we're developing is the Flexible Ramping product. And this really reflects that, you know, our market is changing substantially due to our aggressive renewable goals, and the variation in renewable output and the effects on the energy system where, you know, the LMP to meet peak demand, you know, they're not what they used to be. And, you know, it's--our system is flush with capacity and, you know, peak demand capacity really isn't what the market is valuing.

What the market needs is the flexible ramping capability to respond to variations in, we call it net load, the load minus the renewable output. Most of it--a lot of it's driven by the load changes, but it's also driven by variations in renewables.

So what the Flexible Ramping product does is it projects the ramp in the upcoming intervals, and it projects the uncertainty. And then we have a multi-interval optimization in the real-time market that looks out--it depends on when in the hour it's running--but looks out around an hour. And so the Flexible Ramping product prices

that ramping need and then pays units, usually it's the Opportunity Cost of being held back--it gets more complex than that, but at high level that's what it is.

And that will reduce uplift. Because today with the multi-interval optimization, we might be holding back a unit, a cheaper unit--excuse me, holding back a more expensive unit and letting a cheaper unit set the price, and the multi-interval optimization figures it needs the more expensive unit in upcoming intervals. And if that turned out perfectly, exactly, the units would all be revenue sufficient. But if the forecast is off just a little bit, which invariably it is, then the energy prices don't necessarily support the LMPs. So it adds to uplift.

So we think the Flexible Ramping product not only will it improve our reliability market performance, it should affect the uplift. But those are probably the two biggest changes we're looking at.

MR. FORSHAW: You heard my thoughts about, at least in an initial way, of addressing uplift issues in the previous panel so I won't repeat myself. But I have to say ISO-New England has actually, and Matt White has been leading the participants in general in a series of workshops to try and understand price formation issues.

And I've got to tell you, without that I wouldn't know what anyone was talking about when we talk about--

(Laughter.)

MR. FORSHAW: --convex hull pricing, and ELMP. So thanks for that, Matt.

Specifically, ways to get a better day-ahead commitment schedule to meet the needs, the needs of the system operators. In real-time, one, do a better job of incorporating and pricing the cost of reserves in the day-ahead commitment schedule.

I mentioned before we don't have a co-optimization process in the day-ahead settlements up in New England.

Secondly, again it gets back to cost allocation. You know, if you allocate the cost of uplift to those who are causing the uplift to be incurred, then it will change behavior and you'll have more load clearing in the day-ahead; you'll have resources that get committed you can count on in real-time.

So those are a couple of concrete steps to look at. The other thing, as I was preparing for this and, you know, I'm one of those guys who've been around a long, long, long time, in the late 1990s when we were actually looking to set up the energy markets in general, we had an extended debate about do we go with three-part bidding--you know, energy/startup costs/noload costs? Or do we simply put that on the asset owners and have single-part bidding and let

them go to town?

I wonder now if we'd be having some of this debate if we had made a different decision then?

MS. POPE: Well I think these are all great initiatives that everyone's talking about. I'm going to make one point here, which is probably the only point I had left after everyone spoke on the previous panels today, which is I think it's very important when you think about reforming and improving the price formation, to focus on the real-time prices. And that the day-ahead, you know, assuming we get some of these allocation questions right for the uplift for virtuals, the day-ahead market should follow behind the real-time.

So it should--you know, we need to improve the real-time price formation for reliability because the units that are going to provide faster ramping, or have quicker start times, those are what you need for short-term reliability. Also for long-term reliability. You know, taking the point that the day-ahead prices are going to follow the real-time prices, the investors in new--a new CT, for example, they're looking at the capacity market prices, the energy prices, and the ancillary services prices, and the uplift that they're going to get.

So the pricing piece is incredibly important for long-term reliability. You know, if a new CT knows that

it's going to be just paid its cost, it's going to be getting uplift, it's only dispatched 100 hours a year, very few hours a year, and if it's going to be getting uplift in 80 of those hours, it's not getting anything more than its bid cost in 80 hours.

So in order to get the investment, and the new investment that you need in the markets, you need to focus on these real-time prices that are going to flow into the day-ahead prices.

That being said, I think some of the changes to the constraint modelling that we're talking about here are really important for the day-ahead market. I don't know that they are the cause of this low--this chronic level of uplift that we see in a lot of markets that people have talked about here today.

And I think that comes from just a number of sources of price suppression, especially in the real-time. So I think that in order to get to these longer term objectives like getting the right investments in the right places with the fast-starting units, we need to get the real-time prices right. And I think that should include looking at hybrid pricing. It should include improvements to the reserve markets, the reserve demand curves, making sure that there is some adequate payment for reserves even before you hit the absolute limits. You need those reserve

demand curves in there.

I think we need to look at inter-day changes in offer prices. And I would, you know, ask Rob maybe to talk about that when we get to him, because I think New York has done a very good job with that. That will allow units to really reflect what their actual costs are when gas prices are changing very quickly and we need those units to respond. And it will allow the pricing to reflect that.

And I think we also need to look at five-minute pricing, which has also been talked about here today. That's going to decrease some forms of uplift, and the five-minute pricing is going to--if I'm a unit and I can ramp up really quickly and I'm going to get a high price for the interval that I ramp up, I'm going to have a much greater incentive to do that and to make any incremental investments that I need to be able to do that.

So those are some of the things that I think that we need to focus on to improve real-time pricing.

MR. BERG: Thank you. I think I'm with Richard at least at this point in the debate. I don't think we need new products. I think we need to focus on energy and reserves.

I think we have done a fairly good job in developing shortage pricing in the energy market. I think where we need to do a little more work is reserves. I think

we've heard a lot today that there are units that are online that are clearly providing energy. There are units that are online that are clearly providing reserves as reserves are defined through some local or regional reliability standard. And then there are these extra megawatts that are online and they don't really fit either bucket.

But we do know that they are having an impact on the marginal price. They are lowering it. They are suppressing it. And they are also creating uplift. So I think an area where we need to focus is on dynamic reserves. And I would define the appropriate reserve level to be able to change dynamically, and it would be the amount of megawatts that--you know your load. You know what your defined NERC or local reliability reserve requirement is. And any megawatts above that, those ar extra reserves.

Most of the RTOs, at least in real-time, they co-optimize energy and reserves, and I think it will find a home for these megawatts which we know are online, but they're not really accounted for, and it would align the reliability products with the market products.

In terms of, you know, when you would do that, obviously if you could do that in all hours that would be great. I would pay particular attention to the top ten percent of the hours of the year.

We've heard a lot of, you know, uplift is very

low--this was on the first panel; it's only a dollar, it's a very small percentage of the bill--and all that's true if you look over the course of a full year.

But there's 10 to 15 days a year where it really matters, and getting the right prices right on those days and those hours is really what we're trying to do. And I think that's when you see the conservative operations kick in place. That's when you see the uplift generated. And that's the area where we need to focus.

MR. WHITE: Thank you. That's a fairly rich set of comments and topics to react to, and we're only halfway down the line as far as I can see--

(Laughter.)

MR. WHITE: So I'll try to be brief, but really hit two issues. One is the recent enhancements, and a second is a reaction to--or perhaps a caveat, if I will, to comments Bill and Susan just made.

In terms of recent enhancements, like many of our sister ISO/RTOs we have recently increased our scarcity pricing on two occasions in the last several years, and again this fall. We also have increased our replacement--what's known as our replacement reserve requirements. In some sense it's the same idea Bill just mentioned, although we don't do it quite as dynamically. We're still experimenting with that. But it's designed to take the

amount that we typically have to supplementally commit our system, and instead of doing that as a supplemental commitment it's a constraint that's in our day-ahead market and so it happens in the day-ahead and affects prices through the pricing algorithm that fully reflects those constraints and reduces the amount on average we have supplementally commit.

We're not a very big system. The average megawatts involved are around 160 megawatts. It probably reduces uplift slightly, but I'd emphasize "slightly." It's not a panacea.

Neither of those were intentionally designed strictly to reduce uplift as its goal, but it will tend to have those effects for sure because it raises real-time reserve and real-time energy prices and that will fold back to day-ahead.

Looking forward, we are doing a number of things people have mentioned and in various stages with the stakeholder process. So some of these are actually approved by the Commission. Some of these are previews of coming attractions. But the CTS scheduling system that was mentioned this morning, we are part with both New York and PJM of the three ISOs developing that system which should give us much better visibility about interchange.

We are moving to implement sub-hourly

settlements, which was noted again this morning. Again, designed really to solve other pricing formation issues we're concerned with, but which will have as a beneficial ancillary effect probably some reductions in the net uplift we see.

We also over the long term are making capacity changes that everyone's no doubt well aware of that over the long term will probably produce a much more flexible system, and it's the inflexibilities of high-cost units that ultimately are the root cause of a lot of the uplifts in the New England system.

That said, the caveat I want to point out, or at least a consideration to note, is with respect to thinking that we can simply expand the reserve requirements. I'll stick with the notion of not creating new products, although the same argument could apply to new products, as a way to reduce uplift.

Could it be done? Yes. Should it be done? Not clear. It is a potentially expensive and fairly indirect way to attempt to reduce uplift. Reserves are a very specialized product that can be extremely expensive. They are sold from an offline state, only from offline fast-start units which are expensive to build, or for online units that are available only from a limited amount of their short 10-minute or 30-minute ramping capability.

If we increase our demands for that, that will increase reserve prices. If you increase more money in the energy reserves markets, you will on average reduce a bit of the uplift. But think about what you're doing.

You're spending more demand to buy more of a product that we don't necessarily need more of, and which is very expensive. So it would reduce uplift in a very indirect way by buying more stuff that we don't necessarily need.

Think back to an example that was pointed out earlier in which you think about a resource that was committed for six hours, maybe in the day-ahead market, because its power was needed for one hour across the peak. In our system, many units like that have very slow ramping profiles, so it will run all the way up and all the way back down being uneconomic for the other five hours.

Should we increase our reserve requirements in the other five hours when we may have thousands and thousands of additional megawatts available during those hours just to try to create positive reserve prices to reduce the uplift that goes to the one unit?

Technically, sure. Mathematically we could do this. If you ran the numbers, however, I suspect it would give you serious pause as to whether or not that's a cost-effective use of consumers' dollars because it could be a

very expensive solution because it's a very indirect way to solve the problem, to buy more of a product we don't necessarily need at times we don't need it to shift the way money is spent from the uplift bucket into the reserves market.

So there's a very challenging trade-off here I think that needs to be given significant consideration before one rushes to judgment about whether boosting reserve requirements in general is a panacea to the uplift type problems.

But with that said, I fully admit we actually do a little bit of this with our replacement reserve requirements for a very small amount, and we think it's pretty good so far. But we're tempered in how much promise we think this has, based on that experience.

Thank you.

MR. RAMEY: At MISO I would describe the process we use to minimize and manage uplift as kind of a holistic approach. In addition to being a market operator, we're a system operator. So both of those aspects kind of play in to my thought of how we address the question.

I'll describe quickly how four work streams that are related to the question.

The first is the system operation area. We want to improve our unit commitment and dispatch processes

directly. Real-time is the reference. To that end, we need to focus on getting the day-ahead market right. The day-ahead market needs to include all the real-time constraints that are relevant to a real-time system operator. To the extent possible, we need to build your day-ahead model and administer the day-ahead market in a manner that minimizes balancing congestion.

If you have high levels of negative balancing congestion, that means you're running your day-ahead market against the wrong network and the wrong model. You need to get the day-ahead market to optimize your unit commitment that you deliver to real-time for efficient, reliable operations.

High levels of negative balancing congestion suggests that your unit commitment coming out of day-ahead is less than fully efficient.

You need to support a vibrant virtual market. If you want a good day-ahead unit commitment, you need a good day-ahead set of LMPs that are producing the unit commitment that the real-time will need to run the system reliably.

You need to focus on improving tools like our unit look-ahead commitment tool which we put in place a couple of years ago. It helps operators in the real-time time frame optimize their decisions around making real-time unit commitments.

The second area I would point out is just improving incentives. Improved cost allocation cost causation principle alignment. The allocation of make-whole payments falls in this category with stakeholders. Dr. Patton--we've been working on this issue for at least 10 years. There's probably a few more years worth of work in this area in MISO.

To the extent that you can improve that alignment, you are really going a long way to improving the incentives that are appropriate for individual market participant decisionmaking. As Dr. Patton mentioned, it can be even worse if your current allocation principles are counter-intuitive, penalizing people for taking actions that minimize uplift and improve efficient operations.

The third category is on the market design side, looking at improving price formation. The ELMP initiative I discussed earlier is an example of that. At MISO we still have some opportunities to improve pricing outcomes during emergency operating procedures.

Five-minute settlements is another opportunity to potentially reduce price volatility make-whole payment type uplifts.

And then the category we're working with stakeholders in evaluating possible new market products that could help support reduced or minimization of uplift; 30- or

60-minute reserve products are something that we evaluate from time to time.

As Matt mentioned, it's potentially an expensive solution. But on the other hand, MISO doesn't have 30- and 60-minute reserve products today because they're not needed to meet the reliability requirements of the region.

Another way to think about it is, yes, I do have 30- and 60-minute reserve products in MISO; just the requirement is set to zero.

(Laughter.)

MR. RAMEY: So when the requirement becomes less than zero, perhaps it starts making more sense to add those types of products.

Ramp reserve products is another product that we've already made a filing for and looking forward to a FERC Order in the future.

Virtual spread products have the potential to improve market participants' ability to use virtual type products to further drive price alignment between day-ahead and real-time. And as Dr. Patton mentioned, there are possibilities looking at zonal reserve products that you can introduce to address issues associated with maintaining reliable operations in load pockets.

MR. BOWRING: I don't think my list is anywhere near as impressive as everything I've heard so far, so--

(Laughter.)

MR. RAMEY: Those are things you "could" do.

(Laughter.)

MR. BOWRING: So someone on the prior panel I think introduced an important distinction. That is, why does anybody care about uplift? There are really two reasons.

One is in fact on price, and price formation is a key part of what this is all about today.

But the other is uplift charges to people as who's paying it and does it affect their incentives, does it affect the level of activity?

So I think both are relevant. The first, obviously, about price formation; the second, really, about the total amount. But in both cases it's critical not to make reducing uplift the key goal, because there are lots of unintended consequences worse than the impact of uplift.

So just one example, it's important to not include products which are not really uplift as part of uplift. For example, black-start in PJM. Black-start is a separate, identifiable product with a separate cost. It's not uplift and shouldn't be included as uplift.

There's been a lot of talk about conservative operations and what that means. I think it's clear that it would make sense for the actual demand curve for reserves

during times when the operators believe they need more reserves in order to operate, not all the time but when they believe they need them to operate, to be reflected in the demand curve reserves and therefore that would trickle through and affect energy prices as well.

Part of the reason that uplift matters for price formation is incentives. Right? I mean, why do we care about price? We care about price because of incentives to load, and incentives to gen, to locate, and to build, to invest.

If you have an energy and a capacity price, even if the CT, regardless of uplift, is only being paid in short or marginal cost in every one of the two one hours it runs, it will--the system will work if the capacity market works properly.

So you have to think about the full combination of markets when you're thinking about the system works with and without various levels of uplift.

It also makes sense I think to think--and some are doing this already--to think about more locational scarcity pricing. PJM at the moment only has fairly broad-brush scarcity pricing.

It's also important to think about these persistent local issues. I'm surprised transparency was so controversial a topic. It didn't strike me as being

controversial. But transparency in cases where there are persistent long-term problems clearly can--transparency clearly can let the market determine whether there are profitable opportunities.

Clearly no one is going to invest if there's not a profitable opportunity. But one thing that is very clear from history is no one will ever know if there's a profitable opportunity if you keep it secret. So that needs to be done. In addition to which, the details--there needs to be a detailed logic covering those persistent local issues in the RTEP process. So if the market is not going to solve it, the transmission planning side can solve it as well.

Errors need to be eliminated from the calculation of uplift. There's the lost-opportunity cost that I mentioned. There's the absence of the offset of regulation revenues, and the same thing for the day-ahead reserve product offset not in the PJM model. The five-minute LMP I think would go--also I think contribute significantly to both more efficient pricing and the reduction of uplift.

And while I don't want to spend much time on allocation issues, we agree that allocation issues are significant. We disagree with a lot of what's been said, but it is critical that we recognize that those allocations have incentive effects and our recommendation in fact in the

EMU, I think I know what it stands for, Energy Market Uplift Senior Task Force, is to actually reduce the amount assigned to the deviations bucket.

In fact, our recommendations would significantly reduce, although not eliminate, and charge twice the UTCs, the deviations charged to purely day-ahead products and increase those associated with physical products.

Thank you.j

MR. PIKE: Thanks. So I think, you know, it's been the start of a really good conversation, but I know we've got some more technical conferences to go through. I think it's a continuation of a discussion, though, as uplift has always been a focus of the ISO's parts in managing it and reducing it--needed, unneeded, necessary, unnecessary, it's certainly unpopular. So it's a topic that, whatever it is, it's too much. So it gets a lot of focus.

To that end, when we introduced our updated platform in 2005, we justified the cost of that through a cost/benefit analysis of reduced uplift to the marketplace. The subsequent analysis that Potomac Economics did showcased about $30 million a year in reduced uplift through more efficient commitment of real-time resources.

So it was an extensive opportunity for us to get those tools in place to capture that uplift reduction. Those tools brought us the capability to do economic

evaluations of interchange transactions. It brought us real-time commitment decisions. It brought us co-optimized decisionmaking between ancillary services and energy and clearing prices to go with that on a five-minute basis which aligned with the five-minute settlement that we had in place.

So it brought everything together in terms of prices, schedules, and performance incentives in the terms of settlement together on a five-minute basis to produce that.

In subsequent years to that, we talked this morning about some of the reliability commitments that are necessary for various reasons into the market. We work very hard to get all of those into the market so that they're not after-the-fact commitment decisions; they're into the market.

They are selected commitments in, but they are part of the market so they're not displacing some other resource that's already been committed. They're not distorting prices between the day-ahead and the real-time market.

So for local reliability, for bulk power reliability, for our reliability unit commitment resources are all selected within that market to avoid any distortions between the markets.

An area that we're still struggling with is interchange uncertainty. We heard a little bit about it, and for this I'm really kind of referring to the rescheduled resources day-ahead under an expectation of interchange for the coming day. Are we going to see that interchange come real-time?

And to the extent we have concerns, are we forced into reliability commitments to compensate for uncertainty in that delivery?

Coming out of this last winter, we also saw issues related with performance incentives. Do the resources have all the right incentives in place to be there when we need them on critical peak days?

To that end, we are pursuing a number of avenues, but I'll touch on a couple of them for us today. One is a re-look at our shortage pricing in our ancillary service markets.

We're doing a little bit of all-the-above things. We are looking to add a region for southeast New York that's a specific reserve procurement area. We are looking to increase our 30-minute reserve requirement to address some of that uncertainty that is in the marketplace and provide the resources to the operators to give them a forward binding financial obligation so that there are incentives to be there in real-time, to go buy the gas, to make the

preparations, to do the maintenance, to do the cold-weather hardening such that there's an obligation to be there in real-time and a financial obligation for not being there in real-time.

We are also looking at our shortage--or our scarcity pricing. Our scarcity pricing is related to our activation of demand-response. So this is if we have to call on our emergency demand-response programs, can we clear our energy market consistent with those activations? It is a big block of nondispatchable resources, but given the fact that we've called them at a specific strike price, how do we reflect that back into the market for the other resources that are available?

And specifically what we'll be looking at is aligning the price signals for the DR and the energy providers, and aligning them at the proxy bus locations, at the border buses, so that the interchange has the right incentives to be flowing consistent with price.

Looking at this overall, we're also trying to look very closely from PJM and New England as to what they've established for shortage pricing, to make sure we're in alignment with those decisions. You could have prices flowing in the right direction for price, but in the very wrong direction for reliability if those prices aren't aligned.

So we're taking a very active look at that in understanding how we can align them so that the right signals for prices and the right signals for reliability are combined.

I do think an opportunity for us is transparency. We produce an awful lot of data on the units that are selected for local reliability. We put an awful lot of information together on what triggers exist for uplift, and the total dollars. But we don't have the ability to connect all of those dots together because of confidentiality concerns, to say this constraint caused this uplift on these set of units. I think that's a very real opportunity for us. Will it be acted on? Well, if we don't show it, it certainly never will be acted on.

So I think there's some opportunities for us as a whole, but certainly some opportunities within the NYISO market.

MR. BRESLER: We have reached the end of the line, Will.

(Laughter.)

MR. BRESLER: First I just wanted to sort of introduce this with just a reminder, since some of the other ISO and RTO representatives this morning discussed some of their sort of ongoing day-to-day monitoring activities with respect to uplift. I didn't want silence on that topic to

insinuate in any way that PJM doesn't have those types of programs in place.

Back in about 2008 or so we put a tool in place that we counter-intuitively called "perfect dispatch," and I say counter-intuitively because the express purpose of the tool was to show on a day-to-day basis what was imperfect about the dispatch from the previous day, to really provide very specific analytics back to operations as to what could have been done differently to achieve a more optimal dispatch on the previous day.

We also have tools that operate intraday and actually send real-time messages to the operators when resources are operating in a manner that is above cost and have exhausted their minimum run times so that operators get real-time feedback when those types of conditions are occurring.

And then through ad hoc analysis we actually at the end of 2013 identified one of our day-ahead reliability tools that was over-committing or resulting in the over-commitment of resources for some of those major transfer constraints. And so we actually have been able to enhance our tools such that we get a more optimal commitment going into the operating day and rely more on shorter term, more flexible resource, as opposed to committing longer term inflexible resources.

Looking forward as to the kinds of things we're discussing both internal and in our stakeholder process, we've talked about closed-loop interfaces. I won't say any more about those.

We did discuss how some of the ISOs and RTOs have the ability for short-term inflexible resources, those combustion turbines, to actually set price in real-time. In PJM, we actually are going to take delivery in the next month or so of software changes that will allow us to do the same thing for other types of generation resources--so combined-cycle resources, for example, that are operating at minimum but committed online in order to control a transmission constraint. We'll be able to allow those types of resources to set price as well.

That can have the same type of impact on FTR revenue adequacy, as I discussed with those closed-loop interfaces. To the extent that a resource is operating at its minimum load level and therefore has resulted in reducing the flow on the constraint for which it was scheduled to a level well below its rating, if that constraint is then actually binding in the dispatch and that resource sets price, again if more flow was allowed either in your transmission right model or in your day-ahead market can result in fairly significant FTR revenue inadequacy.

So sort of as Matt White was describing with

respect to a tradeoff in costs and reserve pricing, there can be the same type of tradeoff with FTR revenue inadequacy if you just let everything that you have online set price regardless of what it's doing as far as how much it's reducing the flow on the transmission constraint for which it is operating.

So there are significant tradeoffs to be examined there.

Third, and this has been discussed already as part of this panel, is reserve pricing. From PJM and our stakeholder standpoint, I think we started off with the concept of new products, 30-minute reserve products or something to that effect.

I think where the stakeholder discussion is at this point is probably more along the lines of augmenting our 10-minute reserves in real-time when the operators have made supplemental commitments, most significantly or most frequently on those peak days where there may be the expectation for greater, you know, failures to start on cold days and those types of things.

So augmenting that reserve quantity based on the actual operator actions in order to set the reserve and therefore the energy prices correctly would be the goal of those types of reserve pricing changes.

And then I thought I was going to get all the way

through the panel and be the only one to talk about interchange volatility, but Rob preempted me there. But that's something else that is under specific discussion in our stakeholder process.

Again, we have fairly high hopes for that coordinated transaction scheduling with both New York, and we're under developmental discussions with MISO as well for a similar type of coordinated transaction scheduling approach. But on those, again, peak days where it really is most critical to get the energy and reserve prices right, there may be additional steps we want to take in order to make sure that significant amounts of volatility in interchange quantities don't do things that upset that requirement to really get the prices right during those peak-load conditions.

So with that, I'll go ahead and close and look forward to any further questions you might have.

MR. SAUER: Thank you, all. That gives us a lot to think about. Certainly there's been a lot of thought that you all have put into managing drivers that go into uplift pricing, or uplift for that matter.

Let me look around the room to see if anybody wants to ask some questions?

(No response.)

MR. SAUER: Switching back to the--we'll cover

one last topic. I think we have about 10 more minutes for this panel.

One thing that came up in the last panel, or at least I remember Mark Smith put out one possible option for increasing transparency, and I think he mentioned a daily report that would cover, you know, the driver of uplift. I think he said the resource and the dollar amount, as well.

I would just like to hear from the RTOs or anybody for that matter what confidentiality concerns may be associated with that, and whether that type of information would be informative, as well.

Thank you, Robert.

MR. PIKE: That might be a little more frequent than we were thinking to try to do it. I mean I think ultimately that's the question, is how quickly you can get the data out.

I mean a lot of these are very specific constraints that are packed one unit. So to the extent you're publishing information, that's releasing competitive information, that's, you know, a direction we need to be really careful about moving in.

I think when we're talking about a lot of these constraints, particularly the persistent concentrated ones, you know, we're probably talking about longer duration resources or adds to the system. We're not talking about

somebody just showing up tomorrow and fixing it. We're talking about an infrastructure improvement, a new build.

So I'm not sure of the timing and the quickness of the timing is as critical as the granularity of it when it ultimately gets out, if we can produce it, in a rolled-up enough state for time, that it doesn't expose any confidentiality or competitive concerns, I think it can deliver the information.

MR. SAUER: I certainly don't want to scare anybody.

(Laughter.)

MR. SAUER: I was more just curious as to what confidentiality concerns may exist, if you know, say the total dollar amount that goes to a resource as well as the uplift driver and say the resource name on a given day. It could be a month after the fact. It could be rolled up for a month. It could be rolled up for a day. I was trying to figure out what implications there may be to back in--or by having that information public, what implications there may be to back into confidential information. Hopefully that redirects it a little bit.

MR. BOWRING: So when I was initially talking about transparency, I was talking about longer term issues. So the kinds of issues that have been persistent in PJM for significant periods of time. And in that case, I think that

a great deal of information should be made public, and it's worth the tradeoff against confidentiality.

However, for day-to-day PJM currently does put out estimates of the uplift. It's very difficult to do it accurately day by day because the numbers change, and change significantly, even after a month as various parts of the calculation are fine-tuned.

I think the downside of doing it daily, unit by unit, is it wouldn't be that hard to back in to somebody's offer, and that's really not what you want to do. That would have potentially anticompetitive effects.

So I think there's a tradeoff. And for the routine types of uplift that you're not going to see a market response to in terms of, as Rob said, investment or changes in infrastructure, a little bit less information about the details of the units but information nonetheless about daily uplift and the reasons for it I think would be a good place to start.

MR. SAUER: Brian, I think you're next. Who else? I saw a couple, Susan and Brad, did you want to speak? Okay, it wasn't you. Brian?

MR. FORSHAW: I just have to make an observation when it comes to talking about confidentiality. You know, when something happens on the system and I'm in a Markets Committee meeting, I want to know what happened, I got out

in the hall and talk to people. And they can tell you pretty much what units, and everything else. And it may be because New England is a relatively compact system and, you know, the people who are the ISO wonks have kind of traded hats so many times that they know what's going on, but confidentiality is, you know--there's confidentiality in the information policy, and there's confidentiality in terms of knowing what's going on in the system. And I'll leave it at that.

(Laughter.)

MR. BOWRING: Can I just add, I really strongly disagree with that. I've had lots of people tell me they know who's offering what on the system, and I've offered 'em fifty bucks to tell me. No one has ever come up with a list of units. So, I mean, maybe New England is small enough to have that happen, but it's not something you want to encourage or assume is happening. I mean, that gets very close to anticompetitive conduct. You don't want people's offers shared. It has an impact on the markets.

MR. WHITE: Thank you. I'm going to refrain from commenting on Brian--

(Laughter.)

MR. WHITE: --but rather speak directly to your question. And I'd like to draw a distinction that I'm going to assume, but I want to make it very clear, in the

discussions over transparency in the staff paper as well as some of the discussions this morning, we didn't always draw--the materials didn't always draw a clear distinction between transparency of causes and transparency of payments.

They are different issues. They raise different confidentiality issues. On the payment side--which I took to be the point of your instant question--we publish payments in a relatively aggregated form on what we consider a timely basis. It's every week. You can download it if you want. We have not seen stakeholders pushing us to do anything faster than that, so I would suggest there's not demand for it more timely than that.

Issues do arise with regard to confidentiality if that information was to be highly granular with respect to individual generating units. Without opining, because I don't think we have a corporate position in how the pros and cons would play out, the nature of the things, that if they were sufficiently granular they could, number one, potentially allow people to back out resource offers very quickly, which as Joe mentioned can have adverse consequences.

Second, it could also potentially, how it's done, back out the megawatts provided at a granular level. Note that in the energy markets we do not publish total energy

revenues in a granular way. We publish rates. That is, the prices, the LMPs, but not the dollar payments.

The same thing if we disclosed uplift in a more granular way as a form of rates, but not as payments, it has different implications for what information gets revealed that's traditionally considered commercially sensitive.

So that distinction and the potential, depending how it was done, to reveal traditionally commercially sensitive information about the quantities produced in real-time by the individual generators, or the offers in real-time of individual generators, I think would be the principal concern we would hear in going down that direction.

This is not to say it could not be done in a way that would alleviate those concerns and provide more information to the market. But with that in mind, let me note in closing, Mr. Forshaw's earlier point, we go before our stakeholders and we spend a long time with our COO every month to explain and go over: What was the total uplift? What were the drivers? What system events occurred? Why did they occur? How much detail can we say without being confidential? How can we be not?

You can ask our stakeholders, but my sense is if we did not do that walk-through of the data, the data themselves would be very difficult to interpret. So you

need both pieces to understand what's going on.

Thank you.

MR. SAUER: And it's four o'clock, and the panel is scheduled to end at four o'clock, so we will break on that and thank you all very much for taking time out of your schedules and coming to the Commission.

And we'll just take five minutes. We won't do a formal break, but we will begin panel four in five minutes.

(Whereupon, a recess was taken.)

MR. SAUER: Everybody please take a seat and we'll begin in the next couple of minutes.

(Pause.)

We'll get started here. Thank you everybody who's hung around for the final panel. It's been a very informative day for us so far. There's not a lot of--we aren't trying to accomplish a lot with this panel. We mainly want to know one thing, which is: Are we going in the right direction, essentially?

In the June notice we identified four price formation topics. One of them we're here today to talk about, which is the use of uplift payments. The others are offer-price mitigations and offer-price caps. There's also scarcity and shortage pricing. And the final one is operator actions that affect prices.

All we want to know is: Did we pick the right

four? Should there really be three? Should there be two? Are we here today for any purpose, or should we add any additional ones on, or any additional price formation topics onto that list?

I'll just quickly introduce the panelists and then we can go down the line. I've been going left to right, so we'll go right to left and turn it over.

Robert Weishaar, representing PJM Industrial and Load Coalition. David Patton, Potomac Economics. Elizabeth Whittle, representing Retail Energy Supply Association. David Mohre from NRECA. Harry Singh from J. Aron & Company. And Judith Judson, representing Energy Storage Association. And Susan Pope, representing Electric Power Supply Association.

Thank you, all. And, Robert?

MR. WEISHAAR: Yes. Thank you.

Before I answer your question, I think the Chairman posed a question at the outset of the conference about how uplift impacts our particular interests. In our case, I think we are the only speaker--I'm the only speaker that is representing retail customers, the end-of-the-line so to speak.

I want to make sure everybody understands how uplift ultimately gets to customers. In regulated states, uplift typically flows through fuel adjustment clauses. So

if a utility, a rate-regulated utility, is long and is selling generation, getting uplift payments, that comes through as a credit. If they are purchasing in the wholesale market, that comes through as a charge. It all nets out and goes through a fuel adjustment clause.

In retail competition states, it's going to depend on whether a customer is purchasing default service or purchasing pursuant to a bilateral contract. In default service arrangements, uplift is typically a fixed part of the offer that is made by the wholesale supplier. It comes through and the wholesale supplier assumes the risk that the actual uplift is higher or lower than what was offered.

So what we saw in January 2014, for example, were some of the wholesale suppliers saying uplift charges are going crazy in PJM. We understood that they were going to be a lot lower. And the repercussion was a consequence of the default service arrangements.

In bilateral contract arrangements, the uplift charge can either be variable or fixed. Up until December 2013, in most cases that was a fixed charge. Everybody generally assumed it was about $2 a megawatt hour. It was fixed in retail contracts. Suppliers bore that risk.

In a few cases, customers bore that risk. It was a straight pass-through. But from a retail customer perspective, again it was about $2 a megawatt hour, not big

deal.

Then January 2014 hit in PJM. We saw absolutely unprecedented levels of uplift. And what we're seeing in the retail contracting arena now are retail suppliers either insisting that all uplift costs are a straight pass-through, or we have new terms servicing and retail contracting. And that is, well we can quote you a fixed price for uplift--it's a lot higher than what we quoted you in 2013--but we're also going to include an economic force majeure provision in your retail contract. So that if we get the blow-out we did again like we did in January 2014, then all of that will be a pass-through.

So ultimately the extreme levels of uplift we saw in PJM in January 2014 are coming home to rest with retail customers one way or the other. So that's in response to the Chairman's question about impact on our particular entities.

In response to your question, I think the topics that you have identified for further investigation are relevant. I think some of the changes particularly on scarcity and shortage pricing I think deserve a re-look, given events over the last few years, and does it make sense to continue to have, especially in PJM, levels of shortage pricing above $1,000 a megawatt hour in light of the amount of revenue that's flowing through the capacity regime?

So in our view, it definitely deserves another look. Thank you.

MR. PATTON: Good afternoon. So we've covered a lot of issues I think on the prior panels. I would say that a number of the topics that came up, to the extent that they weren't explicitly mentioned in the staff paper previously, they probably fall under the heading of broader price formation issues.

So I may mention a couple of those. But first I'll go through your list.

The use of uplift payments, I think that one is a candidate for being struck because, as we've talked about earlier, uplift is an inevitable consequence of running these markets. You have to make people whole to their as-offered costs. So it's not that we're using it for some purpose; it's just an outcome. And the better the market is structured, the better it's priced, the lower they'll be. But I'm not sure in and of itself it's an underlying price formation issue; it's more of a symptom of bad price formation.

The second one on offer-price mitigation and offer-price caps, I don't know if I interpreted this correctly but I don't think good market-power mitigation has any adverse impacts on uplift.

So I wouldn't say that it in any way harms price

formation, but I do think what you've seen over time, if you look at the filings that have been made over the last four or five years by the RTOs, is that the underlying drivers of uplift can also be underlying requirements or system conditions that create significant market power.

And so if your market power mitigation is not structured to adequately mitigate those circumstances, you can end up with huge amounts of uplift being generated in a very short amount of time, particularly in cases where you have local requirements where you have one bank of resources all owned by the same guy who has to be--and those resources have to be committed day after day after day, almost any reasonable set of thresholds you apply, that might be adequate for random events where you have to commit somebody and they don't know it's coming ahead of time, if you apply it to that sort of circumstance it's going to look unreasonable.

And so New England, New York, and now I'm recommending in MISO, a set of changes to the RSG mitigation thresholds that, particularly for locational issues, would apply a tighter threshold to RSG mitigation, so that we really are just making people whole for what it costs for them to respond to our dispatch instructions rather than, you know, ten times that.

MR. SAUER: Sorry to interject. We're thinking

of mitigation as it relates to energy price formation et al, and not just uplift.

MR. PATTON: Okay--

MR. SAUER: Sorry if I confused it a little bit there.

MR. PATTON: Oh, no, that's fine.

Then I would say it might be a candidate for striking, then, because I think, you know, the point I've always made about market power mitigation is it does nothing to undermine good price formation. Because if you have shortage pricing that's efficient, it doesn't require that generators increase their offer prices.

So there would be no reason you'd be worried about market power mitigation undermining price formation except to the extent that potentially you might be compelling people to run at below their marginal cost, but that would be a defect in the mitigation.

With regard to shortage pricing, I think there have been significant improvements in shortage pricing. I think it's absolutely critical to do a good job with shortage pricing, particularly pricing local shortages which I think only some of the RTOs have the local operating reserve requirements necessary in order to recognize and price a shortage in a local area, and those are the areas where we end up making a lot of our commitments.

So if you don't price the shortages sufficiently, you can end up in situations where prices are substantially low and you end up having to make significant uplift payments.

But just in general, if you don't have good shortage pricing, particularly in those areas, you have to lean on second-best solutions like capacity market requirements, which are in my mind significantly inferior to good real-time pricing.

The other area of shortage pricing which I think it would be terrific if the Commission thought about this area, and that's transmission shortages. Each of these RTOs exceeds the limits on transmission constraints, sometimes for 5 or 10 minutes, sometimes longer. And in those circumstances, what you're really looking at is a transmission shortage.

They all have some form of transmission demand curve. Some call it a penalty factor. Some call it a marginal value limit. But they do very different things with these parameters. Most of them are not filed. Some of them are starting to get filed. I think they're absolutely critical as far as price formation, so they should be in RTO's tariffs and FERC should be reviewing and approving them.

But over time, if you're in violation those

things ought to set the price, just like operating reserve demand curves do when you're in shortage of operating reserves.

The transmission relaxation algorithm that was occurring in MISO took five years for me to--with a lot of cajoling--to get turned off, and was eliminating $300 million of congestion a year. This is a huge price formation issue. And that algorithm came from PJM. I'm pretty sure it's still in operation in PJM, and I know other RTOs have similar algorithms.

So from a price formation standpoint, I think that would be something that would be very good to look at. It also relates to uplift because, to the extent that you're making commitments in part because transmission constraints, the RTOs are struggling to manage them, if you relax the constraints you're going to end up paying a lot of those units uplift that you shouldn't have to pay if you priced it efficiently.

And then fourth, I think the operator actions that affect prices are difficult to get your hands around, but I'll remind you of the issue that I raised earlier, which is a critical issue.

You can have the best shortage pricing in the world, but if the operators are tasked with eliminating the shortages, then--at any cost, as an economist I would love

to somehow bring together the notion of the operating reserve demand curves and the operator actions, and somehow only allow the operators to take actions that cost less than the demand curve which tells you what the reserves are actually worth.

That's almost heretical in the reliability world that you would let shortages happen that you can see coming, you know the action that it would take to eliminate it and you're just not going to take it because it's expensive. But when you take the action, then it just wipes out the shortage pricing.

So finding a way to overcome that with price-setting is something that can be thought about. It's a difficult task, but ultimately I think bringing those two into alignment would be the real answer.

And then lastly we talked about interchange scheduling as being an important price formation issue, and it really is. A sizeable portion of the shortages that we see could be--as much as I like and value shortage pricing--a pretty big share of the shortage pricing that you see in the various RTOs is directly caused by bad interchange scheduling.

In other words, if you schedule things efficiently, the shortage would have been eliminated. So it does have a significant impact on price. To the extent you

wipe out the prices with too much imports coming in one direction, it does affect uplift.

But, thirdly, it affects the entire decisionmaking of the RTOs. When MISO sees, when prices spike in PJM and MISO sees all their power flowing out the door to PJM, they just start committing everything they can get their hands on. And that's just an uplift machine at that point.

And vice versa. Prospectively what you heard from New England, and I don't think New England is alone, because they can't trust what's going to be happening on the interface, they will preemptively commit things where they-- where something may have a four-hour start time, so they've got to make a decision. That unit's going to be unavailable if they don't commit it now. They have no idea what's going to happen on the interface. Although it might have a lot of space on it, they can't rely on participants scheduling it efficiently, so they'll commit the four-hour unit.

So there's a number of dimensions of interface scheduling that I think have significant impacts on price formation. And so I would submit that it's probably a candidate to think about for this list.

MS. WHITTLE: For RESA, we think the list is quite good. I think we agree about the interchange scheduling, because that does sound like it could be a vast

improvement to the markets.

The other thing that we just wanted to bring to the attention of the Commission and staff is that when changes are made and RESA members participate actively in stakeholder processes, we need to make sure that changes are implemented with plenty of warning and with, you know, transition--moves to implement the program so that we have time to reflect those changes in how we conduct our business so that our customers get the best product that's available.

Thank you.

MR. MOHRE: Good afternoon. Let me apologize first for my voice. I'm fighting a real bad allergy and just yell at me if you can't understand me.

We appreciate the opportunity to talk to the Commission about price formation and uplift in the markets. We think it's a very, very important topic particularly given what's happened with the Polar Vortex.

A small pause for a commercial. I think, as the Commission understands, NRECA represents about 900 co-operatives that are not-for-profit--emphasize "not for profit"--member-owned, member-controlled organizations that provides electricity in all or parts of 83 percent of the counties in the United States.

That's good news. As I like to say, the bad news

is there are not too many people there. But the fact of the matter is, we are member-owned and member-controlled. As to the issue of how does it affect our members, and how does it affect our co=operatives, because we have no independent stockholders anything that increases our costs directly increases costs to our member owners.

We view price formation through these eyes, through this lens, and that is, we look at it and does it accomplish two things? Does it optimize in the short run in a way that moderates the cost to consumers, keeps them as low as possible?

But in the long run, does it also provide the capacity we need and the right kinds of capacity to meet our long-term needs?

When we look at that today, with the hindsight of the Polar Vortex and a few other things that have happened, we conclude that, no, the constructs today do not quite meet that goal, those goals. And particularly the long-term goals.

We feel very strongly that we're not going to be able to meet our long-term goals in terms of capacity and the type of capacity and fuel security, given a single price. We just don't think that will happen.

Our concern with the longer term is based on things that we've all read and talked about that we're

actively involved in. For instance, EPA's 1.11(d), and natural gas prices, where are they going.

We think there is a lot of pressure going to happen on natural gas prices. So between the EPA CO2 rules, 1.11(d) which is going to change the dispatch anyway if it goes through, and also the concern about natural gas prices, we're very concerned that focusing and relying on short-term, very short-term prices that do not value nor price fuel security or fuel diversity is not a sufficient solution.

That is why we are very happy that the Commission appears to be looking at this from a holistic standpoint, not simply the standpoint of does it optimize in the short run? So we're very happy about that.

I will cut through it. I have wonderful, great comments. Please read my written comments, they're brilliant.

(Laughter.)

MR. MOHRE: I'd like to cut through to just two things. We think this is a two-part problem.

After listening to the two panels today, I think that a lot, if not all, of the RTOs are marching down the paths to some of the things we think they should be looking at. Let me talk about the short-term price formation issues and sort of these are backward looking at this particular

point in time, backward looking at where we've come over the past 15 years, and what the Polar Vortex tells us.

We think, number one, we've got to get the gas/electric coordination, whatever you want to call it, correct. If we don't do that, we're going to have uplift forever and in amounts that shouldn't be.

We think we need to revisit operations by the RTOs during the Polar Vortex. Was it Stu, or--I think it was Stu mentioned perfect dispatch. The same idea. Go back and look and see, not to criticize, not to second-guess, but to see what we can learn.

We asked ourselves, gee, in an effort to keep uplift as low as possible, did we forget to turn on some nongas units well in advance? If you look at 13,000 megawatts out of 13.7 thousand megawatts of coal capacity went offline because of what? The unavailability of natural gas for ignition. Gee, I wonder if we should have prepared in advance and done that? I don't know. And, candidly, I'm sure PJM is looking very hard at those issues.

The third thing mentioned by Brian Forshaw of Connecticut Municipal Electric, we need to look at getting the day-ahead and real-time more coordinated. Nobody disagrees with that. We disagree with some ways to do it, and we think this is a major issue.

If you look at some of the numbers that Brian

has, you can see that the deviation is like 6 percent. Okay, you have enormous uplift. If it's 2 percent, you have very little uplift. So I think there's something there.

We'll also talk about the chronic, persistent concentrated uplift and where that can be solved, if you will, in a cost-effective manner. That's very, very important. We need to get on that. I think John Rohrbach mentioned those.

Something we did not hear, and it's a little bit sensitive, we think we need to review the penalties for nonperformance and the definitions of capacity. I know PJM is looking into that as we speak. I think everybody should look at that.

As somebody who's been on the NERC Board of Directors and on the Executive Committee for a number of years, these are important issues.

We also need to, as far as we're concerned, keep uplift in place where it's cost-effective for consumers. And we think a lot of the uplift that occurred because of these dispatch changes is probably cheaper than some other solutions to it. Again, go back and look at John Rohrbach's paper.

So we think it ought to be kept in place for cost-effective solutions to grid problems, but also for policy and environmental reasons. You might ask, well, what

does that mean?

Well for instance is it better to have nongas units online even if they need support than it is to see the price of natural gas go up because there's not sufficient gas and sufficient deliverability? That's just one example. 1.11(d) is another.

I think where we're coming out in this first part is that we need to do all these things and get these right before even thinking about increasing LMP. Let's do what we can, little steps, little-feet kind of thing. And I didn't hear anybody that disagreed on the panels this morning about taking on those issues.

Now to an area that probably will get a lot of disagreement and pushback from. The second part of this is we think we need to look again at capacity markets, not from the standpoint of should we change or anything, but do they really support, encourage, facilitate what we really need, at least what we think we really need? And that is, support viable, long-term bilateral arrangements.

We think that is the only way we're going to get out of this problem, if in fact we can.

We also need to look at those markets, the capacity markets, to see if we can find ways to make sure they support the sort of outcomes that give you good fuel diversity and good fuel assurance. Again, kudos to our

friends at PJM because they're looking at those kinds of things, and they should be.

I guess that's all. And I didn't say anything, except that lat one, that was somewhat contentious. But I would ask this question. And that is, we've heard from some that, you know, the solution is get good pricing and move these costs to LMP.

Well, if moving on average one percent of the cost to LMP is going to solve these long-term problems, I've got a pen here and I'm willing to sign a contract.

I hope I made that point. Thank you, very much.

MR. SINGH: Good afternoon and thank you for having me.

So I'll start by just saying why I care about uplift. The role that J. Aron plays in the market is to provide hedges to generators and load-serving entities. And to the extent there are payments to generators or charges to load that are not reflected in the LMPs, it's difficult to hedge them.

And at some times, as you know, the very hedges themselves, depending on the allocation of these uplifts, become compromised. And that's the example of congestion contracts in PJM.

There was some disagreement earlier on whether a certain type of charge is an uplift or not, so I'll give you

my classification. I put in my slides three buckets. The first one is what everyone understands as uplift, which is the allocation--which is the payment to generators for things that are not reflected in the LMPs.

This could be start-up no-load, this could be lost-opportunity cost, a variety of things. The allocation of that on the flip side then is a charge, and this could be either to load-serving entities, it could be the deviations depending on whether the charge was incurred based on day-ahead or real-time.

The second bucket is demand-response related uplifts. And the interesting observation here is that once you factor in Order 745 payments, the magnitude of uplift related to demand response is really independent of whether the demand response sets price or not.

And this is because there is the component of a make-whole payment, and then there is an LMP payment. When you take the combination of those, the total payment is the same. So price formation here does not come with reduction in uplift; it comes with the same uplift or, depending on the tool you use, even a higher uplift.

The third uplift, and some people don't want to call it an uplift, is this thing called real-time balancing congestion. And I know that Todd Ramey included it. This is interesting because it arises from a mismatch between

day-ahead and real-time transmission models. If there is less transmission capacity in the real-time relative to the day-ahead, then you have this type of charge.

The easiest example I ask people to think of is that when a transmission line goes out in real-time, the ISO has to redispatch generation, move up an expensive generator, move down a cheap generator. That costs some money. The money has to come from somewhere.

So instead of getting congestion rents, there is a congestion shortfall. And the CAISO calls it a congestion offset. PJM calls it negative balancing congestion. It's really a revenue neutrality payment. It does not involve any underlying uplift payments. So in that sense I agree with Joe that it's perhaps a little bit different from the focus of this proceeding.

Nevertheless, it's a big deal in itself. To give you the numbers, in PJM since 2010 the magnitude of that uplift has been more than $1.2 billion. The total revenue shortfall in the FRTs--forgive me for using an acronym--but congestion contracts, has been a little bit in excess of $1.4 billion.

So this has been a really big piece of that. The reason we should care is that back in 2008 when I left the Commission, we had a default in FTRs which was approximately $85 million. It led to a lot of reforms in Order 741, and I

think that to have such a big charge, uplift, whatever label you want to give it, which makes these hedges simply unworkable deserves some attention somewhere by someone.

And then turning to the interaction between uplifts, I think that we discussed already closed-loop interfaces. I just offer that there's an example, September 10th and 11th last year, where PJM dispatched about 1,000 megawatts of demand response in the ATSI zone, but then just like we have seen many other times when you actually get there it doesn't set price because you have more supply.

So in order to reflect that in the price and get good price formation, they employed a closed-loop interface, which is put a circle around the region and dial in the limit that the flows are less than X, and the X equals whatever the flows are, and then the price goes high to 1,800 everywhere in that zone. And the circle can be big or small. In this case it was big.

Well because of the uplift that I just described to you, this real-time congestion offset which arises anytime the limits are different, we created $23 million of uplift. Is that a good thing? You know, it's a little bit different from voltage constraints. I think it's something that PJM needs to think about, and there has to be a better way. And maybe we can look maybe next year in the markets

on what the metrics were, how the thing turned out.

In terms of the other panel topics, you mentioned scarcity pricing. And I think that that's a very important piece because a lot of the uplifts that are related to make-whole payments of start-up and no-load, if you have scarcity pricing triggered properly you probably decrease those.

The experience this summer, though, was that there was a lot of anticipation that we have the ramp up. YOu know, ERCOT has--it's not in our jurisdiction here, but they had some very innovative proposals on the ORDC, another acronym, but it was a mild summer.

PJM has had, in addition to scarcity pricing, something I did not hear discussed, the concept of modeling increased reserves. So they carry 1,300 megawatts of reserves in real-time. The operators, for conservative action, deploy more resources. So PJM has put in place a protocol that the model reserves will be doubled to 2,600 this summer if certain conditions are met.

That was--you know, that has not actually triggered very often, or not at all, but it's an interesting concept from my view.

The one downside there was that there was uncertainty on whether it will be in place next summer. So the role that we play in writing hedges is easier to perform if the forward curve reflects all of these price formation

actions. And if you go and say I'm going to do this this summer but then I'll decide later if I do it next year, it doesn't quite have the same benefit for someone who wants to lock in a hedge.

The last topic that you mentioned was the operator actions. I just note that there are some instances where commitment actions taken by operators may not make sense to reflect in LMPs. Operators often are very conservative by nature, so they will deploy resources and then find out that they have too much supply on the system. They didn't need to commit so many resources.

If you go and reflect those in the LMP, you will create operational problems for the ISO. So there are clearly some exceptions.

Thank you.

MS. JUDSON: Good afternoon. I'm Judith Judson. I'm here representing the Energy Storage Association.

So what I was hoping to talk about is the impact of uplift on investment in storage, but also how storage could play a role in reducing uplift costs. And there's a variety of storage technologies that are viable today, a variety of durations, and really talking about the newer advanced technologies.

So I think, you know, what I heard this morning and in preparing for this conference is uplift is driven in

large part by a lack of flexibility on the system. It's driven by a need to compensate resources' operating limitations, particularly start-up, no-load cost, minimum run times, minimum down times.

And so I would say if you look at some of the newer technologies, there are flexible technologies out there such as storage. Storage is very flexible. No minimum run times; can be started almost instantaneously; can ramp up in seconds; no direct emissions or emissions limitations; and can be sited almost anywhere.

So I wanted to, in keeping with the Chairwoman's recommendation of some concrete examples, at least provide some concrete examples of what storage can do on the system.

So one of the examples raised this morning was there was a need for uplift when there's a need for a resource to meet two peaks during the day, particularly two peaks particularly happens in winter. And the comment was made that you can't bring that resource on in the morning peak, then shut it down, and then bring it back in the afternoon because it has a minimum run time and a minimum down time.

What I would say is, think about it from if you had storage. That storage resource could meet the morning peak. It then could stop during the valley. In fact, it

could actually charge and potentially reduce uplift cost for those resources that are on, providing minimum generation. And then it can be ramped back up to meet the afternoon peak.

In fact, if you look at the Polar Vortex you could have actually had that resource charging in the morning to allow those generators that needed warm--to be on warm standby a little bit of extra time to start up. And you could start those resources earlier, charge the storage, and avoid uplift costs.

Another example is that we've heard a lot about today is the need for a local voltage support or reactive power. And one of the things we saw in some of what PJM has discussed on this issue is that they need to bring resources on to meet reactive services. But if they have a long minimum run time that creates uplift cost.

In fact, quoted on one of their slides was that it's a 4-hour problem with a 24-hour solution. So it's needed for 4 hours; it has to be on for 24 hours. Storage can provide reactive power. It can be located in many areas. And it can be on for exactly the number of hours that it's required.

Another example provided was congestion. Again, I don't want to take too much time going through these examples, but storage can also provide congestion where

needed. It can do so not only by producing energy when needed, but it also could be considered in transmission planning as well.

You know, if you look at the issue of day-ahead versus real-time, the question or example came up with day-ahead minimum run time. You need a resource for the next day, you're looking is it economic during peak, but it's not economic during off-peak but it needs to be on. There again, storage can provide that peak power and it can do so using low-cost off-peak power and actually assist with uplift that's created during min gen because you're using that time to charge storage.

And one more example is the case related to ramping and renewables and the need to maintain sufficient headroom and ramping capability. We look at California that's creating a ramping product. It was discussed by SPP that doesn't have a ramping product but is looking at pricing it into their market. MISO is looking at creating a ramping product here.

Ensuring that market barriers are open to storage can--you know, storage can provide this ramping and do so that also minimizes uplift cost.

So, you know, I think when looking at uplift, the thing to consider is, if there is a cost to inflexibility then there should be a price for flexibility. And today I

think there often isn't a price for that flexibility; it's hidden. And so there isn't a market signals to put storage where it may be needed, and that is probably true of many other resources and technologies that could benefit from a price signal.

So, you know, and things to think about, to see where the opportunity is I think is a little easier than to see where necessarily the actual market solution is, but certainly pricing flexibility into the market. This can either be done through existing products such as energy capacity or ancillary services. But in doing so, ensuring that the market barriers are removed from new technologies.

There could be the creation of new products. There could be a creation of a flexibility product. We do see flexible capacity being created in California. It's really around ramping, but maybe that needs to be expanded.

And then certainly in the issue of planning, when ISOs and RTOs are looking at planning needs on their system, considering not only generation and transmission solutions but storage solutions as well would be one of our recommendations.

And lastly, to the issue of transparency, I think that is definitely where the challenge is, not only pricing it into the market but if there is a need what is that need?

Where are payments going? Could an alternative resource and alternative solution be a better option? It's very hard to know that without transparency in the markets.

So with that, my comments.

MS. POPE: I think this is a good list of topics. I don't have a lot to add here beyond what other people have said.

I agree with the idea of adding a topic or a part of a topic that has to do with interchange scheduling. I think that's a good idea.

I'd also suggest that the second topic on offer price mitigation and offer--and price caps possibly be broadened a little bit to look at the price formation step a little more broadly, and at things that can be done to improve that price formation step such as the five-minute pricing we've talked about, or possibly the hybrid pricing.

That being said, I think everyone's recognized there definitely are interactions between these topics where uplift is really resolved, sometimes of price formation problems. Operator actions are in large part a result of other problems with price formation. So there's definitely interaction here, but you have to slice it up somehow.

I think the one thing that I will speak for my client on is I think there's a real sense of urgency in terms of trying to find ways to improve price formation that

are relatively--or expedient.

You know, we've heard a lot of ideas here today about what the ISOs are doing, and there's a variety of opinions about different directions to go, and there are a lot of very good ideas. But I think somehow if this set of workshops could start to sort through some of what those good ideas that could be done quickly are, or that have been proved because they've been implemented someplace and could be passed over someplace else.

I think that, you know, what--I agree with--I think this has been expressed before here today, it would be very interesting to see what we can achieve when we improve the real-time price signal. Some of the other things that we think that we might need to do may diminish in importance because the uplift is going to be decreased.

So if we can try to find the expedient ways to improve that real-time price signal, I think that would be a great result of this series of workshops.

MR. SAUER: Well thank you all very much. I think that was the goal of the panel, and there's not--we thank you, very much.

Commissioner?

COMMISSIONER MOELLER: Thank you. That was a really great panel. I've only seen one this morning, but I've seen a lot of good presentations. And I was getting

all ready to make my point, and then, Susan, you made it for me.

With respect to David and you, I grew up on co-op lines--I still have the ranch--on those lines. I appreciate your perspective of holistic approach, but I'm kind of impatient on this, which may rub Jamie and our Chairman the wrong way, but it seems to me there's got to be a little bit of low-hanging fruit we can get for ahead of this winter with an agreement that will get more of it together.

But I mean I just don't think--I think we have to assume we're going to have a bad winter and be happy if we don't, but we're cleaning up a lot of the problems of last winter all through this year in our Orders. And I want to see what we can do.

If you have any ideas on the urgency factor and what you'd recommend first, and if you think it's a mistake say that, too.

MR. MOHRE: I--oh, sorry. Go ahead.

MR. SAUER: Bob?

MR. WEISHAAR: Yeah, if we're talking about moving uplift into real-time prices, I don't agree that there is an overwhelming sense of urgency.

Where we do perceive an overwhelming sense of urgency is figuring out what the heck happened in PJM in January 2014. And just so everybody understands, the couple

months, looking at total balancing operating reserves in PJM, the couple months before January 2014, was $31 million, $13 million, $17 million, $36 million; we get to January, it was $564 million, all of which came through either to retail suppliers that took fixed positions and got burned, or retail customers that had variable passthrough on uplift charges and got burned.

We haven't done a thorough root-cause analysis to figure out why we had an extreme blow-out in uplift causes in January 2014. And you look at the months subsequent to January '14 you get $56 million, $59 million, $9 million, $20 million, $15 million. Much more moderate levels of uplift, certainly not monthly uplift totals that just scream out for a sense of urgency.

January, though, sticks out. And we have asked for information and data, and I think it is incumbent on the Commission to restore public confidence in the existing uplift rules, because generally they're working pretty well. When you have monthly averages, except for January 2014, of $20- to $25 million in a multi-billion dollar market, that's not a driver of customer outcomes.

When you get an extreme case in January 2014 of $564 million in uplift, that warrants urgent attention.

COMMISSIONER MOELLER: Before we have other answers, which I encourage from everyone if you want to, I

do want to point out that Jamie did have real good reasons for not being urgent. So I just happen to disagree with them, but it wasn't that they weren't well thought out. And, you know, part of it is we want to build enough of a consensus to make sure this is defensible. But I'm an impatient person.

The other point I want to bring up in case it's relevant, which is that--and I appreciate our Chairman letting me do this--I'm doing something independent of the Commission the afternoon of our open meeting in September to focus on, for those of you who follow the April 1st tech conference, kind of roughly speaking how we can get better transparency in natural gas pricing when the markets are closed and on the weekends.

Because my gut feeling--and again I could be wrong, and we need to see more evidence--is that that drove a lot of what we're talking about because of, you know, it was clearly a buyer's--or it was a seller's market when we were particularly going into those long weekends where there was a lot of gas obtained that wasn't necessary. And then the prices obviously to sell it back were significantly lower than what they paid.

And we have a number of filings where we're dealing with that, but if you have thoughts on that, and that's an open invitation for anybody to attend the

afternoon of the open meeting, I think it is somewhat relevant to our discussion today.

MR. WEISHAAR: I certainly agree with that statement. We will be there on the 18th. And I think if you look at the--start to unpack, I mean what we know generally about January 2014 is the inflexibility on the natural gas deliverability side was a primary driver.

Another primary driver, though, is a reaction to what occurred in early January in terms of generator performance, and the need for conservative operations in late January in anticipation of the potential for similar performance in late January. That also warrants attention.

MR. SAUER: David?

MR. MOHRE: Yes. Just a comment that I wasn't suggesting we go slow, but prudently, I guess is the word. There is a lot going on now, as you heard from the panels. We support some of it, not all of it, but let's let this wonderful process go through and see what we get.

To us, the real, excuse me, the drop-dead date is really the year after next, not this year, from the standpoint of 1.11(d), and MATS, and how that will affect. I mean, as I pointed out in my comments, you think it's bad now? Try doing it in two years when PJM will have 10,000 megawatts of nongas generation that disappears.

You think we've got problems in scheduling gas

and gas prices now? Just wait. And so we share your urgency. I'm tempted to use the old bromide about Mary Anaise repent in leisure. We need to really be careful here because the--I know I have a friend at Harvard who talks about this being a grand experiment. We tend to think it's the lifeblood of our industry. So we think it's a little different than that.

MR. PATTON: Yeah, unfortunately I think I'm going to disappoint you with, you know, giving you a solution that can be replaced by this winter, but I do think it's important to not underestimate the importance of good shortage pricing.

I think--I run into people virtually every day that are worried about, you know, do we motivate enough flexibility? Do we motivate people to firm up their fuel supplies? Do we motivate people to have dual-fuel capability? All these things that we really care about, and they want to create, you know, in some cases, new products to handle a lot of these things. But if you value things correctly in the real-time and you have good shortage pricing, you motivate people.

If our gas supplies are not reliable, a generator that can burn something other than gas makes a huge amount of money, or if they can firm up their gas, or get an option, or put in dual-fuel capability. And so that's why I

think shortage pricing is just critical. It's critical in the short term for those reasons; it's also critical in the long term because the worse it is the more you rely on capacity markets that have much more ambiguous performance incentives than shortage pricing does.

If you're not available when the shortage happens, you lose. So the more of your investment incentive that you can put into shortage pricing, the better.

And the other thing that I think is important just to think about in these contexts, and the reason why I stress these things, is transitory shortages are shortages. The reason why we want people to be flexible is because we have 10-minute shortages.

You heard Todd Ramey say I'm concerned about ELMP? Well I'm concerned about ELMP because it looks like it's destined to wipe out a lot of our transitory shortages. Some people think that's great because price volatility is not good; in my opinion, that's horrible.

If we have a 10-minute shortage, it's a real shortage. And if we want people to be flexible, and we want people to have fast ramping capability, you need to price them and not employ pricing mechanisms that mute that price volatility. Price volatility is only bad when it doesn't reflect a real underlying issue on the system.

So we can't solve all of our shortage pricing

issues by this winter, but I do think in the long run it will address a lot of the fuel diversity and other issues that people are concerned about.

MS. SIMLER: So it looks like when we get to the point in our price formation project where we get to talk about scarcity and shortage pricing, that we'll have the makings of maybe a great panel in some of the folks that are here.

(Laughter.)

MS. SIMLER: Just an observation.

MR. SAUER: Judith?

MS. JUDSON: Thank you.

You bring up the question of urgency. I don't know if I can offer a solution for this winter, but what I can say is there is urgency with looking at alternative solutions, removing barriers to technologies. Because if you don't start now, it's longer and longer before you get solutions.

And I often hear the comment, you know, that's an issue down the road when we have more renewables. That's an issue down the road when this happens, or that happens. But I think what we saw this winter is, you know, things can get, or the need for flexibility can grow astronomically under certain conditions.

So to the extent that ISOs and RTOs are looking

at this issue considering the ways that there are technologies out there that are coming on the grid that at this point are proven from a technology standpoint can play a role in these issues, I think is--it needs to start now looking at it.

And there are markets looking at it, but we need to make sure it's being looked at across the board, and I think even a little more holistically.

MR. MOHRE: Let me comment a little bit about the shortage pricing argument that Dave just made.

There are two kinds of incentives. One is a carrot, one is a stick. Candidly, in the short run, and PJM did this in their analysis, one of the things that they pointed out was the penalties for nonperformance were really weak, number one; and they had force majeure provisions that I will describe as you could drive a truck through them.

If you're going to get capacity market payments, we need to tighten up those provisions. And that is going to be on us, too. We have generation but we need to tighten those provisions.

That's at least a start. Now I'm not saying that solves the problem. Shortage pricing may take longer to get. But to talk about something you can do now, and then work on the other, is something.

MS. POPE: Just in terms of possibly something

that can be done quickly and, you know, the ISOs will have to reflect on this, the one thing I can think of is the interday changes in offer prices.

New York has done that. ISO-New England is doing that. I don't know, quite frankly, about the other ISOs, and I don't know how difficult the changes are to the, you know, to the customer interface, the bidding interface for doing that, but that strikes me as something you might be able to do fairly quickly.

COMMISSIONER MOELLER: Well thank you. And I'm sure our market monitors will have something to say about that, too. But thank you for letting me ask the question first, and again it was not meant to at all be disrespectful. You just know where I'm coming from now, if you didn't already.

But my gut feeling is, you know, and I could be wrong, and people can disagree with me, but if we can get the pricing right in the real-time, a lot of the controversy and the extraordinary effort of changes in capacity markets will, not completely, but a lot of it fades away.

Thank you, Madam Chair.

CHAIRMAN LaFLEUR: Thank you, Commissioner Moeller, and thank you to all the panelists in the four panels over the course of the day. I think you did a great job in making what's really a pretty complicated topic very

real, and also largely avoiding acronyms.

I also want to thank the team that put the workshop together, and all the ones that are coming, and thank Will for keeping up the energy and keeping us on track in prep and over the course of the day.

I both agree with my colleague that there's an urgency to learn from what happened last winter, because if football is here winter can't be far away, but I also agree that some of the emerging trends--David spoke about MATS and things that are coming in the future that are also--you know, we have to look both with an eye to the past and with an eye to the future.

I think the quote of the day for me was Joe Bowring when he said "if it was easy, we would have done it already." I always say that all of the energy issues seem to come down to having to somehow achieve reliability, the environmental requirements, environmental improvement, and cost at the same time.

And I was reminded several times over the course of the day when the folks are there in the control room in the middle of the night, whether it's Pete Brandein keeping on the lights for my friends and neighbors, or all the people around the country, reliability is not optional. They are going to do all the things they need to do. That's what happened in the Vortex. That's what happens other

times.

And meeting the environmental requirements that are coming at us fast and furious that are important to the future is not optional, either.

So how well we get this right in terms of all this geeky market stuff depends--is going to determine how much it costs to do those other things.

And some of the themes that really resonated for me over the course of the day were the importance of aligning what happens in the day-ahead and that happens in real-time. That came through time and time again.

The seams and the interchange schedules were raised many times. And then I didn't really--it's almost a semantic whether we have new products, whether we refine the energy product to price in more, whether we refine the capacity product the way New England and PJM stakeholders are working on, whether we put in new products like CALISO, whether we change the alignment where people get paid more ancillary services and less something else, but some way shape or form reliability has to be fully reflected in the product.

And so whether it's new, not new, it's just semantics. That's what we're talking about is evolving the markets for reliability.

So I think this was a great kickoff and look

forward to the next one and the continuing conversation. Thank you.

MR. SAUER: And thank you, everybody, for coming out. I have nothing better to say, so have a safe trip back and thank you.

(Applause.)

(Whereupon, at 5:06 p.m., Monday, September 8, 2014, the technical conference in the above-entitled matter was adjourned.)