BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

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Demand Reponse Compensation in : Docket No. RM10-17-000

Organized Wholesale Energy :

Markets Technical Conference :

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Hearing Room 2C

Federal Energy Regulatory Commission

888 First Street, N.E.

Washington, D. C. 20426

Monday, September 13, 2010

The above-entitled matter came on for technical conference, pursuant to notice, at 9:02 a.m.

BEFORE:

DAVID HUNGER, Office of Energy Policy Innovation

CAROLINE DALY, Office of Energy Policy Innovation

ARNIE QUINN, Office of Energy Policy Innovation

CARL PECHMAN, Office of Energy Policy Innovation

JAMIE SIMLER, Director, OEPI

MICHAEL McLAUGHLIN, Director, Office of Energy Market Regulation

MICHAEL GOLDENBERG, Office of the General Counsel

HELEN DYSON, Office of the General Counsel

ALSO PRESENT:

JON WELLINGHOFF, Chairman, Federal Energy Regulatory Commission

PHILIP MOELLER, Commissioner, FERC

JOHN NORRIS, Commissioner, FERC

CYNTHIA A. LaFLEUR, Commissioner, FERC

PANEL I (NET BENEFITS TEST):

JOHN KEENE, Director, Regional & Federal Affairs, Massachusetts Department of Public Utilities

ANDREW OTT, Senior Vice President, Markets, PJM Interconnection

ROBERT ETHIER, Vice President, Market Development, ISO New England Inc.

JOEL NEWTON, Senior Attorney, NextEra Energy Resources On behalf of New England Power Generators Association

SAUL RIGBERG, Utility Intervenor Attorney, New York State Consumer Protection Board

AUDREY ZIBELMAN, President and CEO, Viridity Energy, Inc.

DONALD SIPE, Attorney, Consumer Demand Response Initiative

ROBERT A. WEISHAAR, JR., Attorney for Demand Response Supporters

PAUL PETERSON, Consultant for Public Interest Organizations

STEPHEN SUNDERHAUF, Manager, Program Design and Evaluation, Pepco Holdings, Inc.

ROY SHANKER, Ph.D., Consultant, PJM Power Providers Group

PANEL II (COST ALLOCATION):

PAUL CENTOLELLA, Commissioner, Ohio Public Utilities Commission

WILLIAM HOGAN, Ph.D., Professor, Harvard University

IRWIN "SONNY" POPOWSKY, Consumer Advocate, Pennsylvania Office of Consumer Advocate

MICHAEL ROBINSON, Senior Manager Market Development, Midwest ISO

CARL SILSBEE, Manager of Resource Policy and Economics, Southern California Edison

TIM BRENNA, Director of Wholesale Markets, National Grid

KENNETH SCHISLER, Senior Director of Regulatory Affair, EnterNOC, Inc.

ANGELA BEEHLER, Senior Director, Energy Regulation/ Legislation, Wal-Mart Stores, Inc.

MEGAN WISERSKY, Electric Planning Manager, Madison Gas & Electric Company for Midwest IDUs

JAY BREW, Counsel, Steel Manufacturers Association

P R O C E E D I N G S

(9:02 a.m.)

MR. HUNTER: Okay, great. So thanks for coming. Before I introduce the first panel and go over today's format, I will start with a brief history of how we got to where we are today.

In March the Commission issued a Notice of Proposed Rulemaking regarding Demand Response compensation in organized wholesale energy markets. A number of comments were received, and many of the commenters raised issues regarding the possibility of a Net Benefits' test, and also various methods of Cost Allocation for Demand Response compensation.

In order to get those items on the record, we issued another Supplemental Notice of Proposed Rulemaking in August and set up this conference here today within 45 days of that issuance. I think we're on day 38, so we made it in under 45. And we sought comments regarding those two issues, the Net Benefits test and Cost Allocation methodologies.

And so we are here today. There will be another round of comments within 30 days of this conference, which will be August 13th. Also, all of the statements from the speakers will be put on the record. So that can be part of what generates responses.

And let me explain the format. We've got a lot of speakers on two panels, one of Net Benefits this morning and the second one on Cost Allocation this afternoon. We also understand that there is some overlap between the two issues, so panelists on one panel may discuss issued related to the other panel.

And there is an implicit--I guess it is now explicit--assumption that the NOPR proposed to pay full LMP is in place, all this discussion is under that assumption. And thus the focus of the first panel is to discuss how the Commission could decide how to establish a test of the Net Benefits to determine whether the benefits associated with paying full LMP exceed the costs. And if so, in what hours, and how that would be measured. We have already received a lot of comments on that.

And the focus of the second panel discussion is as to how to allocate the payment of Demand Response, assuming they're being paid the full LMP again.

A little bit about the format. For each panel, we will start with brief opening remarks from each panelists, five minutes or so. We've got the clock right there (indicating). We have two-and-a-half hours for each panel, so that should leave about an hour-and-a-half for follow-up questions and a discussion among the panelists and the staff after the opening remarks from all the speakers.

Just a reminder. We are on a live webcast, so please be sure to turn on your microphones when you are talking. And just some housekeeping. After the first session, we will take a one-hour lunch, an approximately one-hour lunch, and we should be resuming around one o'clock. Before I introduce the panelists and the staff at the table, let me turn it over to the Commissioners.

Chairman Wellinghoff, Commissioner Norris, and Commissioner LaFleur are here.

CHAIRMAN WELLINGHOFF: Thank you, David.

First of all I want to say that Commissioner Moeller is going to be a little later. He's dropping his twins off to school today for the first day of school, so that's a momentous occasion that I wouldn't want any father to miss, but he will be here soon.

Commissioner Spitzer unfortunately could not join us today, but is very interested in the subject and will be reading the transcript of the proceeding.

I think this is an extremely important meeting we are having here. As David indicated, the presumption here is that there should be equivalent compensation for equivalent services, and that's where the Commission started here. We started with giving the full LMP to Demand Response for bidding into these markets.

And I still believe that's the correct result.

It's a presumption. It's a presumption certainly that is subject to being rebutted. We want to hear today from those people who support that presumption, and those here today who have some evidence and information that might rebut that.

We really want to hear why, if at all, the Commission should adopt a Net Benefits test. And I am particularly interested in determining whether or not adopting such a test will be outweighed by the costs of developing and implementing such a test. I am very concerned about that.

I am concerned about the fact that implementing such a test may in fact dampen the amount of Demand Response in the markets, number one. And number two, it may in fact have a retarding effect on competition in the markets.

So when you are talking about a Net Benefits test, if you are supporting such a test, please address those issues; because I think the test in fact could be so complex and so cumbersome as to again have costs outweighing any benefits of such a test.

And with that, I will turn it over to Chairman Norris--Commissioner Norris.

COMMISSIONER NORRIS: Thank you, Mr. Chairman. Thank you all for being here. We have quite a crowd this morning. I think that is indicative of the interest level in this topic.

I always say, from my standpoint, we want to get Demand Response as robust and functioning out there across the economy and across this sector as we can, but it is important that we get it right. And determining value is tough. We face it not just in Demand Response, but in a number of other areas.

So you are here today because we really are trying to get this right. And these are two issues that I think are critical to have a further discussion on, so I am glad we are having it and am glad you are here so we can-- there are a lot of questions still about how we get this right, but we need to move this forward, Demand Response forward in our economy, and I hope this can help get us there today.

So thanks for being here.

COMMISSIONER LaFLEUR: Thank you, Commissioner Norris. Good morning. The benefit or burden of going last, it's easy to be short because everything has been said; but I also welcome everyone here. Really, we are very grateful for the very high level of interest in the rulemaking and the comments we're receiving.

Much earlier in my career I was directly responsible for running Demand Response/Early Generation Load Management programs for customers. So I know they can work. I know they deliver savings to customers and can help with reliability, and can help with making markets work well. Although there were no markets back when I was--no competitive markets back when I was running them.

But for all the reasons that it has so many benefits, sort of the flip side is that Demand Response touches markets in a lot of different ways and has a lot of impacts on energy markets and energy utilization. And that is why this issue is so important; and the issue of how we pay for it, and how we structure that is so complicated.

So happy to have so many smart, experienced people in the room and am very interested in hearing what you have to say. Thank you.

MR. HUNTER: Okay. Thank you.

So with that, let me introduce our panelists and the Commission staff at the table, and then we can get going.

We have John Keene, Director of Regional and Federal Affairs for the Massachusetts Department of Public Utilities. We have Andy Ott, Senior Vice President for Markets at PJM. Robert Ethier, Vice President of Market Development, ISO New England.

Joel Newton, NextEra Energy. Saul Rigberg, attorney with the New York State Consumer Protection Board. We've got Audrey Zibelman, President and CEO of Viridity

Energy. Don Sipe, attorney representing Consumer Demand Response Initiative. Robert Weishaar, Jr., attorney for Demand Response Supporters. Paul Peterson, a consultant representing Public Interest Organizations. Stephen Sunderhauf, Manager of Program Design for Pepco Holdings. And lastly, Roy Shanker, consultant representing PJM Power Providers Group.

And at the table for Commission Staff, we have Caroline Daly from the Office of Energy Policy Innovation; Michael Goldenberg from the General Counsel's Office; Arnie Quinn from the Office of Energy Policy Innovation; David Hunger, OEPI; Carl Pechman, also Office of Energy Policy Innovation; Jamie Simler, Director of the Office of Energy Policy Innovation; Michael McLaughlin, the Director of the Office of Energy Market Regulation; and Helen Dyson from the General Counsel's Office.

With that. I think we can begin. We will go around the room like this (indicating), and we'll start with John Keene from the Mass. Department of Public Utilities.

MR. KEENE: Thank you.

Again, my name is John Kenne from the Massachusetts Department of Public Utilities. But today I am here on behalf of the New England Conference of Public Utility Commissioners, NECPUC.

I would like to thank staff and the Commissioners for inviting us here today for this important technical conference.

NECPUC endorses the use of a Net Benefits test for determining when to compensate Demand Response providers. We essentially have four recommendations for you.

The first is to require use of a Net Benefits test.

Second, we recommend that you refrain from prescribing a standard Net Benefits test across all the regions.

Third, we recommend that you provide clear guidance on the objectives that such a test should seek to balance.

And fourth, require each region to develop its own test consistent with those objectives.

The Commission proposes to compensate Demand Response at Full Locational Marginal Price in all hours. NECPUC agrees with compensating DR at Full LMP for the reasons we stated in our initial comments, but allowing such compensation in all hours may unreasonably increase costs to consumers in certain circumstances.

Procuring Demand Response's supply at Full LMP results in fewer billing units over which to recover costs. This is referred to as "missing money." If the benefits resulting from decreased prices are outweighed by the missing money, the additional resulting costs to consumers may be unjust and unreasonable.

Such an outcome may also be inconsistent with the concept of least-cost dispatch inherent in the Standard Market Design. Thus, it is imperative that the benefits resulting from increased prices outweigh the missing money. Whether dispatching Demand Response results in Net Benefits depends on the characteristics of the supply offers in the bid stack.

A Net Benefits test should only allow Demand Response to participate, or be dispatched, when these benefits are most likely to ben positive.

As long as the per-unit increase in costs is outweighed by the overall decrease in prices resulting from displacing higher-cost marginal resources, compensating Demand Response at full LMP will benefit consumers, will make the energy market more competitive, and will enhance the reliability of the system.

Accordingly, using a Net Benefits test to determine where price reduction is likely to be greater than the cost to procure is an appropriate means to integrate greater levels of Demand Response into the wholesale energy market, while balancing the interests of consumers.

As noted in our initial comments, NECPUC recommends use of a dynamically adjusted minimum-offer price model like that currently used in New England's Day Ahead Load Response Program.

And addressing the Chairman's note about cost, considering the experience we have had in New England with that model I don't think the costs of developing or implementing such a test would be so great that we shouldn't use one.

That said, the Commission need not and should not prescribe a standard Net Benefits test in its final rule; rather, the Commission can and should allow each region to develop its own mechanism for determining Net Benefits.

Other regions may have a different supply mix and may have different resource types on the margin than New England. The frequency at which a particular resource type if on the margin also varies across regions.

NECPUC's preferred model essentially establishes a proxy for the marginal unit and, accordingly, may be able to be adapted to circumstances in other regions. However, due to unique regional characteristics, this model may not be as well suited in some other regions; or other regions may simply prefer another model.

Regional stakeholder forums are better suited for assessing regional characteristics and determining which mechanisms are most appropriate for each region.

Accordingly, NECPUC recommends that the Commission not prescribe a standard Net Benefits test and allow each region to develop its own mechanism to be reviewed in a compliance filing.

Although we do not recommend prescribing a standard Net Benefits test, the Commission should provide guidance for establishing such a test. To that end, the Commission should consider objectives of a Net Benefits test that should guide formation of regional tests.

Any Net Benefits test should first and foremost ensure the integration of Demand Response provides all market customers with Net Benefits. However, the Net Benefits test should also consider the following objectives: mitigation of price formation concerns; protection of the integrity of baselines and other methods of measuring and verifying load curtailment; and balance wholesale and retail Demand Response.

Price formation concerns relate to behavior that may theoretically increase total production costs to society for procuring electricity. Such concerns, which have been raised in the past by some on this panel, relate to potentially inefficient price signals when an entity that responds to high prices by curtailing demand receives two income streams--the first from savings for curtailment; and the second compensation from the energy market.

In theory this may provide an incentive for some consumers to either consume or utilize distributed resources that are more expensive than central station resources. NECPUC has stated that Demand Response resources should be economically justified from the perspective of the wholesale market without concern for broader societal impacts such as customer bill savings from curtailment.

Demand Response resources should not be denied a payment equal to the full LMP on the basis of price formation concerns. However, price formation concerns should not be entirely ignored, either.

Use of a Net Benefits test will limit the circumstances under which Demand Response may participate or be dispatched, thereby mitigating at least in part concerns over price formation.

Another objective for acquiring a Net Benefits test is to protect the integrity of measuring and verification mechanisms. Rather than requiring consumers to purchase energy in advance, which in our view is simply the equivalent of compensating Demand Response at something less than the full LMP, a customer's expected purchases form a baseline from which their curtailment is to be measured and evaluated.

If a customer is called upon to provide Demand Response too frequently, identifying their baseline usage patterns becomes increasingly difficult to measure and verify with precision. Accordingly, a Net Benefits test that limits participation or dispatch to a limited number of hours will minimize the potential distortion of consumption baselines and preserve the integrity of measurement and verification.

The final objective NECPUC recommends be considered is the impact that participation in wholesale markets may have on retail Demand Response. As SmartGrid technologies and pilot Demand Pricing Programs are rolled out, competition from the wholesale market has the potential to affect the pace and depth of penetration of price responsive demand at the retail level.

We agree with Professor Kahn that retail rates should not be permitted to undermine efficient wholesale rates. However, nor should wholesale rate mechanisms--at least those designed in part to compensate for inefficient retail designs, such as procuring demand as supply--be allowed to hinder the introduction of dynamic pricing mechanisms at the retail level.

There is tremendous technical potential for Demand Response at both the wholesale and retail levels. Use of a Net Benefits test that limits the hours in which wholesale Demand Response would be dispatched will help to minimize these unintended adverse impacts on nascent retail programs.

Thank you.

MR. HUNTER: Thank you. Thanks, John.

Andy Ott from PJM.

MR. OTT: Good morning. Thank you for the opportunity to appear before you to talk about this subject of benefits tests for Demand Response.

Clearly Demand Response provides benefits both to the wholesale market operation and to the regional grid operation. And in PJM we have seen nearly 10,000 megawatts of Demand Response resources clear in our Forward Capacity Auctions.

We have up to 16 percent of our Synchronized Reserve market that is supplied by Demand side resources. Although the amount of economic Demand Response we've seen clearing in recent years, like this year for instance we're seeing around 100 megawatts of Demand Response clearing in certain hours, where two years ago it was more like 800 to 1000 megawatts. Even though we're seeing less of it clear, the amount registered and eligible to participate remains at levels above 2000 megawatts. So we're looking at some lower prices not providing the incentive to actually clear.

RTOs can of course develop metrics, benefits tests, to show the aggregate benefit of Demand side participation in the markets. We can estimate these benefits again across time periods. I wouldn't want to get too granular, but monthly, seasonally, some type of static measures, from that perspective we certainly can do at reasonable cost. It would not be a costly thing to develop what I'll call aggregate benefits analyses. In fact, I think it would be beneficial to develop such a transparent mechanism that's relatively standard.

However, if you take--you have to use caution to actually take a benefits test and apply that to compensation, because you may have unintended consequences.

The implicit assumption in developing a benefits test for purposes of compensation would be that you could actually determine individual customers, whether they benefitted or not. That type of analysis would be very costly to implement. That would be cost-prohibitive to actually go down to a granular level to assign value to an individual customers or individual time periods.

There's a couple of reasons for that. The first is just going and doing analysis on that granular level to essentially repeat market outcomes with and without Demand Response would be difficult to implement and costly.

The second, even if you were able to do that, then you have to assign benefit to individual customers. There's many other aspects of market positions that customers have--bilateral contracts they cleared in different types of markets--and actually gathering that information and trying to attribute whether a price reduction would have been beneficial or not to a certain customer based on their hedging would be prohibitively even more costly to try to go gather that kind of information, which really isn't readily available for instance to RTOs.

In our previous comments, we've actually acknowledged, and I realize that a proposal to make direct payments to customers is not a simple answer. Certainly paying full LMP, LMP is the value in the market of Demand Response, but depending on the retail structure underneath the customer--in some cases, paying full LMP would be fine from the wholesale side. In other cases, it could pay full LMP from the wholesale side but may create unintended consequence because of the retail rate structure underneath.

So that issue we talked about in our previous comments and I won't continue.

I did want to talk a little bit about, though, price responsive demand as the next evolution, at least that we're discussing within the PJM market, which again is really automated customer response to innovative retail rates and enabling technology, of course. So that's two-way communication and the appropriate type of technology to support those rates.

We've worked with states to develop an improvement to our Demand Response roadmap, and develop that type of document for people to use. We've worked within our stakeholder process to discuss the market rules under price response demand. Unfortunately that hasn't yet gotten consensus. There's a lot of competing interests there. We actually owe you a report, and we'll get that to you within a week or so based on a requirement we had to report on that progress.

But under PRD, energy would only be consumed by the customer if the market price was above LMP and they would see that directly because they're responding directly to that price through an innovative structure.

Probably the last point I would make is that, as we see this innovation moving forward--meaning the implementation of innovative rates and technologies--effectively what you will see here is that type of innovation will drive customers to innovate in how they consume.

So I think it is better to put our efforts there. Because if you put your efforts there, you really don't need a Net Benefits test then, because you actually see the customers be directly incented through that.

I appreciate the opportunity and look forward to your questions. Thank you.

MR. HUNTER: Thanks Andy. Next up we've got Robert Ethier from the ISO New England.

MR. ETHIER: Thanks for the opportunity to be here today.

First I would like to note that ISO New England is strongly support of Demand resources. We have approximately 2500 megawatts of Demand resources participating in our markets today, and we have recently implemented a state-of-the-art communications infrastructure that gives us real-time telemetry information from these resources and real-time communications with these resources. And we have found that has worked very well. And we continue to work hard to better integrate Demand resources into all of our markets.

I have three primary comments that I would like to make today, three primary points I would like to make today.

First is that the Net Benefits definition that we're talking about should match that of economic efficiency. So true Net Benefits are the difference between the value consumers receive from energy and the cost of energy production. But Net Benefits are not equal to the consumer savings less payments for Demand Response.

So first, what's the definition of "Net

Benefits"? And our view is we believe it should coincide with our Tariff, and also with the definition of "economic efficiency."

Second, a Net Benefits test must consider all ISO administered markets. It shouldn't focus solely on the energy market because the markets interact. So price effects in the energy market have feedback effects in other markets, primarily the Capacity Market.

And then third, ISO New England has done some analysis in conjunction with the Brattle Group looking at the payment of the full LMP, both the payment of full LMP under various conditions, payment of LMP minus the retail rate, and real-time pricing; or by the baseline approaches. And we have looked at those things in the short run and in the long run to estimate Net Benefits from those circumstances.

And what we found is, paying the full LMP results in negative Net Benefits. Real-time pricing and LMP minus the retail rate results in positive Net Benefits. There will be a handout available, if folks would like to see sort of the details behind that study.

So first, ISO New England is committed to maximizing Net Benefits that are economically efficient. As I mentioned, our Tariff requires us to run economically efficient markets, and we believe the definition is consistent with the way economists define "economic efficiency," which is really the area between the Demand and the Supply Curves. We believe that is the appropriate way to define Net Benefits.

Second, and this is something that's easy to--well, I think the discussion to date has mainly focused on energy market effects, but it is clear the energy market isn't the only thing that would be affected by how you decide to pay price responsive Demand resources.

To the extent that paying these resources, and getting them engaged in the market reduces LMPs, that is going to have carry-on effects into the capacity market. Those effects are easy to describe.

For example, generation gets money from both the energy and the capacity markets. To the extent that energy market revenues decrease, they're going to increase the amount that they need to recover from the capacity market before they either enter the market, or before they retire from the market and de-list.

So those consequences are pretty clear, and we think that that's something that folks ought to consider when we calculate the Net Benefits of any system that we set up to pay price-responsive demands.

And third, we've taken a look at empirically what would happen if you implemented paying the full LMP and these alternative structures that I've talked about?

We've really looked at five different approaches to price responsive demand.

The first one is: pay full LMP in all hours.

The second is: pay full LMP subject to an hourly Net Benefits test.

The third is: pay full LMP in high-priced hours, loosely speaking, the top 10 percent of the hours.

We looked at LMP minus the retail rate.

And we looked at real-time pricing, or by-the-baseline approaches.

As I mentioned, negative Net Benefits for the situations where you pay the full LMP; positive Net Benefits for when you pay either the LMP minus the retail rate, or when you have real-time pricing or by-the-baseline.

Speaking specifically on the Net Benefits test, the analysis I think is helpful in answering some questions. What it shows is the Net Benefits test is passed in the vast majority of the hours. So out of 8760, we were getting positive Net Benefits from some Demand reduction in 7600 hours.

What that says to me is--and that is looking at--sorry, and I need to be clear--that's on the consumer savings, if you implement the Net Benefits as a consumer savings test. What that says to me is, if your goal is to pay full LMP and your test is consumer savings, don't bother with the Net Benefits test because it's not going to apply, and frankly it is not going to effectively limit the hours of operation at all, in case you get clearing in virtually all hours of the year.

And I can certainly talk in more detail about that in the Q&A section.

MR. HUNTER: All right. Thanks. Next up we've got Joel Newton representing the New England Power Generators Association.

MR. NEWTON: Thank you for the opportunity to participate in this panel. I will make two brief points by way of introduction.

First, the Net Benefits test is severely problematic. It sets forth a structure that will distort the decision of when to procure Demand Response. This distortion not only is inefficient but can equate to the exercise of buyer market power or market manipulation.

The core problem is that the Net Benefits test measures when to procure DR based on the overall effect the procurement decision will have in terms of suppressing energy prices marketwide.

This would determine Net Benefits in the short run to Load. In fact, the purported benefits are simply wealth transfers from suppliers to Load. This is not Just and Reasonable under the Federal Power Act. Let me explain in more detail.

The proper way to conceptualize when to procure DR is that a particular consumer should forego consuming electricity when it would rather save the cost of consuming power than consume power. If the right price signal is given for this decision--and that, I submit, is LMP-minus-G, then there is no need for the benefits test.

DR occurs precisely when it's efficient to forego consumption. In contrast, under the Net Benefits test we would procure DR not when it is efficient for the consumer to stop consuming but when price suppression effect exceeds that cost.

We thus face the prospect of paying the DR resource more than is necessary to induce the resource to stop consuming in order to achieve the net benefits for load. This way of thinking is directly analogous to the trading strategies the Commission found potentially to constitute market manipulation in Amaranth and ETP.

There the Commission was deeply troubled by traders allegedly trading against their economic interests in one market to benefit positions in other markets. So, too, here.

Load would overpay for DR inducing conservation, or in many cases for industrial consumers the ability to turn on dirty, behind-the-meter diesel generators that they own, for the purpose of broadly reducing wholesale prices for retail consumers. When a more efficient decision would be to continue consumption.

This is not simply an abstract thought. In reports sponsored by the New England Load Interests in 2007 and 2009, Synapse Energy Economics described a cost/benefit analysis for procuring DR that expressly incorporates something called "DRIPE," or "Demand Response Induced Price Effect."

In a nutshell, they expressly contemplate deciding to procure a DR not because it is an economic procurement decision on a stand-alone basis, but because of the purported benefits of suppressing prices in the energy markets.

This is really the mirror image of a generator withholding. On a standalone basis, a generator would be acting economically; but if the resulting reduction in supply drives up the clearing price, then that loss may be more than offset by the increased revenue earned by the rest of its portfolio.

It would hardly be a valid defense to a charge of withholding to point to the profits earned by the rest of the supplier's portfolio, but that is really what we're doing under the entire Net Benefits test, and asking FERC now to bless this very process that would not be permitted if it were done on the supplier side.

The Net Benefits test is really the equivalent to DRIPE. Whether to procure a DR is, in effect, distorted by the potential for load, reaping the short-term benefits of energy market suppression. Both metrics are inefficient and unlawful.

Second, I would like to briefly address Professor Kahn's recent affidavit. This filing is very close in an important way to Dr. Shanker's affidavit for NFCA in this proceeding. As Dr. Shanker explained, DR should be conceptualized as a call option. The consumer effectively purchases the option from the LSE to call electricity at a particular strike price. That is, the retail rate the consumer pays to the LSE.

Professor Kahn agrees with viewing DR as a call option, but he fails to follow through on the logic of that view, which is that the consumer that offers DR must pay the strike price, the retail rate, in order to provide DR to the market.

Professor Kahn and Net Benefits supporters propose to solve half the problem. They would have the Commission supplement the retail price signal, but would omit the necessary component of reflecting in that price signal the need for the DR provider to pay the strike price for its call options. That is, again, the retail rate.

This position advocates intentionally reaching the wrong result, over-compensating DR and then hoping that each state commission will take counteracting measures to cure the mistake.

The better course, and the only course consistent with Just and Reasonable Rate outcomes, is for the Commission to create the correct price signal at the outset. Thank you.

MR. HUNTER: Thanks, Joel. Next up we've got Saul Rigberg from the New York State Consumer Protection Board.

MR. RIGBERG: Thank you. Good morning, everyone, and I would like to thank the FERC staff and the Commissioners for organizing this conference, especially Caroline for inviting the Consumer Protection Board.

To set my remarks in context, I would like to say a few words about the New York State Consumer Protection Board. The Consumer Protection Board is a state agency in the executive branch of the New York State Government statutorily charged with representing the interest of consumers of the State before Federal, State, and local administrative and regulatory agencies.

In the late '90s, as the New York Independent System Operator was being developed, the CPB was designated by the NYISO as the state-wide consumer advocate representing the interests of the State's residential, small business, and farm electricity users in the NYISO governance process.

The CPB has participated fully in the NYISO's stakeholder process since the inception of the NYISO. We are a member of the End Use sector and have been able to vote in the governance process.

More recently, we spearheaded an effort on behalf of the End Use sector to convince the Board of the NYISO and the CEO to designate at a senior level a consumer advocate, or not really an advocate, a consumer liaison who will have access to the CEO and be able to advise the End-Use sector when issues come before the many hundreds of working group meetings that we can't always attend when issues come to those groups, working groups, that might have an effect on end-use sectors, the End-Use sector, and we are able to use that liaison to find the technical people at the NYISO to help us better understand those issues.

In contrast to the generators who are well represented at the NYISO, the consumer groups tend not to have the staff to attend all the meetings, and that is why it was felt a consumer liaison was useful.

The other thing--just commenting on efficiency, economic efficiency, the Board of the NYISO has decided to amend the Mission Statement to clarify that by "economic efficiency" they mean lower prices for consumers. So the focus we thought had to be more on consumers and not just on this abstract phrase of "economic efficiency."

So we largely agree with the comments of Mr. Keene regarding the need for paying full LMP when there's a net benefit to consumers.

And by that, we would say generally that we mean that as long as customers receive a reduced amount of--a reduced cost of energy due to the use of DR, then it's appropriate to pay the cost of the DR.

We would say that that would be looked at from a zonal perspective, not an individual customer perspective, that the prices are reduced because you use DR--unless energy is needed to be purchased from that next highest cost generator, then it makes sense to use DR.

The other comment I just wanted to make is I think no matter what approach you take to paying for DR, the loads can always turn on a dirty generator behind the meter. I don't think that's, you know, I don't think that's dispositive of which approach you take.

And I just wanted to comment on some of the questions that were asked in the supplemental NOPR. Okay. In general, we think that societal costs are often not included in these considerations.

For instance, you people talk about cheap call, but one reason call is cheap is that the mining and the health and safety regs do not really--are not adequate in our opinion, to fully cover the cost of call, and mountaintop mining, for instance, allowing that, reduces the costs of calls. So the full cost of that type of that energy source is displaced to the whole society, especially the communities in the mining area or the individual miners.

But it would probably be a little complicated to figure out societal costs like that. So we would not suggest that in this case, but just do a simple test of would energy prices come down if the DR is used. I guess maybe in contrast to Mr. Keene, we would not want further seams to be developed.

We've been working for ten years dealing with seams with PJM and ISO New England, and now we've been working on this broader regional markets initiative that's very valuable, but it's expensive and time-consuming. So we would like there to be just one test in the region anyway. Thank you.

MR. HUNTER: Thanks. Next up we've got Audrey Zibelman from Viridity Energy.

MS. ZIBELMAN: Thank you, and thank you for the opportunity to be here. I also won't be commenting on whether not load should get full LMP. I think I'm assuming that prices will be the locational marginal price, and really the only issue before us then is there a threshold.

Another way to say it: Is there an amount of Demand Response in the market that we would say so saturated the market that we can't have any other, can't have any further benefit? And I would agree with Saul that the benefit should be: Is it going to have a positive effect on the marginal costs? In other words, will it have an effect on either reducing the marginal costs in the market as a whole or impacting or avoid an increase in the marginal cost?

In that context then, we would suggest three things for the Commission to consider in terms of a recommendation. The first is that just from a practical matter, as I did a calculation, as you're talking about load in the markets, of the 8760 hours a year, normally when we talk about on-peak pricing in the 5 by 16, that's the classic, you're only talking about 4,000 hours a year.

In most instances, load is not going to be participating every hour of the year. So you're probably talking somewhere in the order, and in all our studies and working with customers who are in the real-time dispatch, probably about 3,000 hours a year that they're looking at, and they really are looking at on-peak.

So in fact the market itself is a natural effectively threshold, because people are really looking at participating when it's economically valuable to them.

The second thing is I would recommend that the Commission at a minimum say that there will be absolutely no Net Benefits test applied in the day-ahead market.

Getting load in the real-time, in the day-ahead dispatch is going to be hugely valuable from the perspective of transparency, market liquidity, the ability for LSEs as well as virtual traders to start getting a real sense of elasticity of load--and again we're talking about controllable load, not all load. And then having it in the day-ahead market will make the markets that much more transparent, which is of course one of the things that we've tried to achieve by having these markets in the first place.

The second--the third is, in terms of the real-time market, we would recommend that any threshold, if the Commission feels the need to set a threshold, has to be at the level that it's confident that the additional participation of demand in the market will in fact have no impact on reducing the marginal cost--revenue requirement, as my colleague Alan Friedfeld would say, and that it also would have no impact--would also have no beneficial impact on avoiding price increases.

We always think in terms of lowering price. I always think of it as like we want to bang our head against the wall until it starts bleeding, and then we want DR. Let's have the DR so the prices don't get up as well.

So in terms of that, we would suggest that the Commission, if it's going to set a threshold, really look at what's really where the most efficient price is, which is at the baseload units, and then we'd see if there's additional--we'll even see if we can even get there with DR. If we do, I would say that's a high class problem to have.

In terms of that, the reason why we would recommend that is one, is we've got to stop thinking in terms of Demand Response as turning on old units. That's not what we're talking about anymore. It's talking about integrating storage, all types of storage, whether it's I-storage, battery storage with photovoltaics.

It's talking about control systems, very advanced control systems, microgenerators, combinations of wind, all types of resources that we want to put at a distributed network and integrate, and turn load itself into a controllable real-time device on the grid.

The reason we want to do that is not because just--it's because of price, it's because what we're really recognizing is that for the last 120 years, the entire industry has been focused on optimizing everything in front of the meter. Now we have the technology and the communication tools to talk about optimizing behind the meter, and putting in these resources so that they can be used to help balance the grid.

To do that then, the last thing I think the Commission wants to do is set a threshold price to say "Oh, we don't want that much of that stuff. We only want the traditional generation." We have to move this grid into what we would see as an optimized self-balancing network.

So to do that, and the reason we want to do that is not as a condition for price. it's also increased reliability. As we're looking, as we're moving towards more alternative generation, solar, wind, the ability for a grid operator to control load and have load respond to the real-time price signals is hugely valuable, in terms of now we can actually have load follow wind and solar, et cetera.

The other reason is that we can use reactive power; we can have regulation; we have reserves. All those things increase reliability when we use distributed resources to the maximum, and the best thing is is that we're using the same asset base, usually to serve multiple purposes.

So from an economic efficiency standpoint and societal benefit, such as the battery we're putting at a train station in Philadelphia, it's doing multiple things at once, which is really what we want to do as a society.

The second is is that you don't want to--we want to get to more efficient markets. That means more liquidity, more transparency, reduced congestion. All of that happens when you deploy distributed resources and you put them into the day-ahead and real-time dispatch on the same basis as generation.

The other piece is we want to have innovation and we want to have a lot of investment. I can tell you from working now, since I've worked on the high side of the meter and now I'm working on the other side of the meter, it's just as complicated. People are just as concerned and even more concerned about reliability, and there's lots of investment they want to make in control systems, in storage, in generation.

They want to do it because they want to be participants in the market; because they bought the story that this is going to be a Smart Grid in two ways. So they want to be actually proactive members, as opposed to just passive consumers.

So in all those reasons, that's where we think we need to move. So in conclusion Commissioner, you know, we appreciate the opportunity to be here. We think that we're at the cusp and I'm seeing it just sort of on the ground right now, of a huge amount of interest on the part of users to get engaged in the market, to deploy their capital so that they could participate in the market, and what we need to do now is just to set the market price right.

The nice thing is is the market price is right, because we're very careful when we sit that the locational marginal cost, which as Professor Kahn said, is the right price in this type of--and for this sector.

So I appreciate the opportunity to be here and look forward to your questions.

MR. HUNTER: All right. Thank you, Audrey. Now next we've got Don Sipe, an attorney for Consumer Demand Response Initiative.

MR. SIPE: Yes, thank you. We appreciate the opportunity to be here and discuss the issues in the supplemental NOPR. I want to point out that CDRI has provided a white paper in its initial comments, that addresses most of the issues in the supplemental NOPR in one way or another.

That white paper, although this panel is focused on the need for a benefits test, that paper deals with the allocation issues and "missing money" problem, and those portions of that paper are independent of whether or not there is a benefits test or not. So those subjects are not impacted by my remarks today, about whether or not there is a benefits test.

I want to make few points initially. First, the Commission's NOPR presumes you want to integrate these resources into the market as fully as possible. Setting artificial thresholds and tests that are not similar to generation resources doesn't allow the head-to-head competition, which is the whole point of what the NOPR is trying to do.

So immediately when you begin to set those thresholds, you are backtracking from one of the major objectives that you set out to solve with the NOPR, and we recommend against it.

CDRI has an approach that can operate as a Net Benefits test. It applies marginal cost pricing signals, and the information in marginal costs, to DR equally with generation. It rolls the additional cost of DR, because of billing unit effects, right into the day-ahead price, and it deals only with the day-ahead market.

So that it's visible to the market, you can see it at the time of consumption, which are all-important things for consumers, and then it allows it to dispatch in any hour, any hour at all, where it is better than the generation price. It is a fairly simple, straightforward algorithm which simply adjusts for the load. It is not complicated math.

But regardless of whether that test is adopted or any other test is adopted, LSEs raise legitimate concerns about the missing money problem, and about their ability to hold themselves harmless. Those algorithms that we presented can solve that problem independent of whether it's used to clear resources, and we think that's fairly important, that that aspect of the market be done too.

Because as we can hear from some of the other panelists, we think the Commission is going to be continually refighting the LMP battle over and over again, both with people trying to define what a Net Benefits test is by saying paying LMP doesn't provide benefits, or by allocating costs in different ways. So we want to emphasize that it's very important that the allocation be done correctly to preserve the initial goal of the LMP market.

Our approach is compatible with the Commission's desire to dispatch DR resources in every hour in which they clear, and we think that that's important because it's important for the market to be structured in that way.

The question of whether or not there needs to be a Net Benefits test at all is important. The algorithms provide an empirical way for the Commission to look at the market, and at anticipated loads, and make a reasoned determination, in my opinion, that no Net Benefits test is needed.

I don't think you have to guess. I think if you look at reasonably anticipated loads and reasonably anticipated levels of DR penetration in the market, that you will find that doing an empirical test, which sees whether you can spread the added cost of DR over the load in almost every case, that adjustment is going to be very small. There are going to be very few hours where any spread at all between a DR bid and a generation bid does not result in DR being beneficial to the market.

You'll get 70,000 megawatts, which is a nice baseload number for PJM in the market, and you spread the cost of incremental billing units for 100 megawatts of DR over 70,000 megawatts, and if there's a penny difference between those two bids, that DR will clear and it will be beneficial.

The advantage of looking at it through our algorithms is that the Commission has an empirical way to make a reasoned determination, based on mathematics, that we don't need this most of the time. A simple tie breaker could do it.

So even though we believe Net Benefits are important, we think we've provided an empirical way for the Commission to determine that in the real world, with the type of loads that Audrey's been talking about and other people have been talking about, there is probably not a need for a Net Benefits test. But if one is adopted, it should not be an artificial threshold which can be wrong both ways. It should not be a mechanism that treats DR differently than generation. It should be a direct application of the marginal cost pricing principles which have recently been advocated and correctly by Dr. Kahn, and it ought to be just based on correcting for the billing unit effects, and making sure that ratepayers benefit. Thank you.

MR. HUNTER: All right, thank you. Next up we've got Robert Weishaar, an attorney for Demand Response Supporters Group.

MR. WEISHAAR: Thank you, David. I'd like to thank the Commission for this opportunity to present a perspective on the issues raised in the supplemental NOPR. I have the privilege of serving as counsel to CMTC and PJM-ICC, which are coalitions of industrial and large commercial customers, with facilities in MISO and PJM respectively.

These companies are both potential providers of Demand Response and customers who will be paying for Demand Response. Both have been participating in these proceeding with the Demand Response supporters group.

I emphasize the following points:

Point one: An LMP-based system of pricing naturally regulates the amount of Demand Response that will be provided. No commenter in this rulemaking is seriously disputing the fact that Demand Response provided in an LMP-based energy market will provide benefits to customers in the form of lower LMPs.

While this may not be true in each and eery five minute increment, it is clearly true over the course of extended periods of time. In some hours such as during peak load hours, the benefits to customers will far exceed the total of LMP payments to Demand Response resources.

The often-cited study of certain peak load hours in PJM confirms that the benefits of Demand Response are capable of being multiples of the full LMP payments to the demand responders. In other hours, whether an LMP-based net benefit occurs may be a closer call.

This possibility of negative Net Benefits in particular hours, however, does not mean that administrative intervention must occur to define precisely a positive-negative Net Benefits break point for each hour. Rather, it is important to recognize that low LMPs during any close call hours will have a self-regulating impact on the amount of Demand Response being provided.

During these hours, as LMPs decrease, Demand Response output will also decrease, because compensation will be insufficient to cover Demand Response providers' short-term dispatch costs, however those Demand Response providers define them. The self-regulating effect will occur, whether demand resources are dispatchable or self-scheduled.

The same effect should occur and does occur on the supply side. The bottom line is that if supply side resources are permitted to find on their own the price point at which continued output becomes economic, then demand side resources should also be permitted to find on their own the price point at which continued output becomes economic. Administrative intervention is not necessary.

If the Commission determines otherwise and tries to develop some administrative break point for making Demand Response compensation unavailable, or ceasing Demand Response compensation altogether, the Commission must consider whether the extreme net benefit gains that occur during peak load hours should be carried over and spread across those hours in which the Net Benefits may be slightly negative.

For example, if $5 million in Demand Response payments produces $650 million in avoided costs for customers during a single week, that 645 million in Net Benefits should be credited to Demand Response providers, and offset any slight negative Net Benefits that may occur in other hours.

Consequently, the netting should occur not only within an hour but across hours, such that extreme Net Benefits during certain peak load hours should be available to offset any slightly negative Net Benefits during certain off peak hours. Doing otherwise would be an overly-myopic approach and not provide full credit to Demand Response resources.

Point two: Administratively constructing an LMP-based break point for compensating Demand Response participation would ignore many other qualitative and quantitative benefits of Demand Response. Focusing only on the LMP impacts of Demand Response is problematic.

As we've seen in a lot of the comments that have been filed, and as the Commission has found, there are a number of other qualitative and quantitative benefits of Demand Response. Any Net Benefits test that looks only at the LMP impacts of Demand Response in any five minute or 60 minute increment, and then curbs Demand Response based on that test, will prevent the delivery of the substantial non-LMP benefits of Demand Response.

Point three: The Commission should require periodic reviews of the benefits of Demand Response under a full LMP approach. CMPC and PJM-ICC firmly support a full LMP during all hours approach to Demand Response compensation. That support is rooted in substantial and compelling evidence that Demand Response is good for customers and good for society.

However, we are also on record recommending that the Commission periodically evaluate all aspects of approved market designs, to ensure that all aspects are working toward a customer-oriented end. Demand Response compensation is no different.

The Commission should require each RTO to submit every 24 to 36 months an analysis of whether compensating

Demand Response at full LMP for all hours is providing Net Benefits to customers. That analysis should address not only the LMP impacts of Demand Response compensation, but also an analysis of other quantitative and qualitative effects. Interested parties should have a reasonable period of time to file comments on the analysis.

Thank you again for the opportunity to address the Commission. We will be augmenting these brief remarks with written comments, which we plan to file jointly with the other members of the Demand Response Supporters. Thank you.

MR. HUNTER: All right. Thank you, Robert. Next is Paul Peterson, a consultant representing the Public Interest Organizations.

MR. PETERSON: Good morning. My name is Paul Peterson, and I want to thank the Commission for the opportunity to present the views of Public Interest Organizations, on the questions raised by the Commission in the Supplemental Notice of Proposed Rulemaking.

This panel is focused on the need for a benefits test for Demand Response. I have three observations that apply to the topic of this panel as it relates to a day-ahead energy market. First, there needs to be a benefits test for the acceptance of Demand Response offers.

Second, the benefits test should utilize a dynamic, not static threshold.

And third, the incorporation of demand resource offers into wholesale markets is a critical development stage for the overall effectiveness of market mechanisms for selling and purchasing electricity.

Public Interest Organizations are in agreement with many of the other participants here today, that Demand Response resources must be allowed to offer in the day-ahead market, and be paid the locational marginal price, LMP, when those offers clear.

The issue directly before this panel is whether there should be any limitation to the rule that the Commission has proposed in its order initiating this rulemaking consistent with the overall objective of competitive markets, and mechanisms to help ensure that rates are just and reasonable, as required by the Federal Power Act, and with the existing operational procedures that are used to select resource offers for a day-ahead commitment there is a limitation or a benefits test that should be applied to Demand Response resource offers in the day-ahead market prior to their acceptance. This can best be understood by reviewing the current day-ahead commitment mechanism used in wholesale markets,

In simple terms, the current practice is to place all the day-ahead offers into a bid stack, and the market administrator moves up the bid stack until enough resources have been selected to meet the anticipated day-ahead load. The price of the last resource selected sets the day-ahead locational marginal price.

In the day-ahead commitment process, however, the market administrator considers each resource offer parameters, such as start-up, no-load costs, minimum run times, and minimum down times that are linked to each resource's offer. The market administrator will select the combination of lowest price offers that produces the lowest overall daily commitment cost.

During that selection process, a higher-priced offer with greater flexibility may be chosen over a lower-priced offer with less flexibility. The simple example is a high-priced offer with a two-hour minimum run time, and a slightly lower price offer with a 24 hour minimum run time.

If you're trying to solve a four hour peak load issue, it is overall cheaper to accept the higher-priced offer for two hours than accept the slightly lower-priced offer and have to pay it for 24 hours. This process produces a day-ahead resource commitment schedule that represents the least cost combination of resources over the 24-hour commitment period, while meeting system reliability standards.

Demand Response resource offers need to be evaluated in a similar fashion to generation resource offers. In addition to their start-up costs, minimum run times and other parameters, Demand Response resources should also be evaluated as to their impact on overall daily commitment costs.

When the DR resource is accepted, the total quantity of load that is paying for all the resources is slightly reduced. If a generation offer and a DR offer are the same price, and all their offers are roughly equivalent, all their offer parameters are roughly equivalent, the choice of the DR offer instead of the generation offer will raise costs, the LMP to all load.

The DR offer, as other commenters have stated, must be slightly less than the generation offer by a sufficient amount to offset the price increase caused by the reduced quantity of load in the day-ahead market. Because the megawatt size of most DR offers is small compared to the overall load, the price difference between DR and generation can be very small, often just pennies apart, and the DR offer will still provide a net benefit to all day-ahead market participants.

The Consumer Demand Response Initiative has proposed an algorithm that can evaluate each Demand Response offer as it is reached in the stack of offers, and calculate the total cost of the load with or without the Demand

Response offer. If the DR offer lowers overall costs for the day-ahead commitment, then it can be accepted. If it does not lower overall costs, the next slightly higher generation offer should be accepted.

Parenthetically, the CDR algorithm can also do the cost allocation for all of load, though that's the subject of the next panel. Something similar to the CDR algorithm could be incorporated into the commitment mechanisms that are currently used to clear the day-ahead wholesale markets.

This is the threshold or Net Benefits test that Demand Response resource offers should satisfy to be accepted. This will produce the lowest cost combination of resources, both generation and Demand Response, to meet the needs of wholesale market consumers over a daily commitment period. This threshold will produce day-ahead prices that will help achieve rates that are just and reasonable under the Federal Power Act.

Some commentators have suggested that a static threshold for Demand Response resource offers be established, based on the cost of electricity from a benchmarked unit, usually a moderately efficient gas unit. Under this approach, if a DR reseller offers at a price less than the threshold, it is not accepted. If it offers at a price higher than the threshold, it can be accepted based on its place in the overall stack of offers.

The problem with the static threshold, even one that is updated monthly, is that it is a less precise mechanism to do what a dynamic threshold mechanism can do automatically. The actual supply stack is not a smooth curve on a graph that we use in presentations.

Instead, it is a lumpy set of offer blocks at increasing prices or steps. A static threshold will cause errors in both directions. Sometimes, DR resource offers will clear, even though they will increase overall daily commitment costs. On other occasions, a DR resource offer will not clear, even though it would have lowered overall commitment costs.

A static threshold will also discriminate against legitimate DR resource offers simply because they are a low and arbitrary threshold, without consideration of whether the DR offer accurately reflects the DR provider's costs. Static thresholds can also disallow DR resources with minimum run times if any hour of the run time falls below the threshold, without consideration of the overall impact of the DR offer over all the hours of run time.

A dynamic threshold mechanism such as the CDRI algorithm evaluates each DR resource offer using consistent criteria that applies to generation offers too. Public Interest Organizations urge the Commission to include some form of a dynamic threshold test as part of the rule in this proceeding.

The significance of a compensation rule for Demand Response resources cannot be overstated. The evolution of the bulk power system has focused on how to expand generation and transmission resources, to meet the historically fixed demand of electricity customers.

Throughout the 20th Century, certain rules of thumb applied. Load would increase every year, except for temporary dips during economic recessions. Load was largely inflexible. It varied based on weather and time of the day, but those variations were very predictable, and electricity could not be stored either efficiently or in large quantities.

Technological change has turned those 20th Century rules of thumb into myths. Greater efficiency in the use of electricity means that total electricity consumption can decrease, while economic output can increase. Many loads are becoming more flexible and some loads are willing to forego consumption for brief periods if they can be compensated for their choice, to reduce their consumption or not use electricity at all.

Storage technologies are improving and may experience quantum gains in the near future, with the deployment of vehicle to grid electric cars.

Starting with the initial implementation of Day 1 and Day 2 markets over a decade ago, the absence of demand participation in the wholesale markets has --

MR. HUNTER: Wrap it up.

MR. PETERSON: Pardon me?

MR. HUNTER: Wrap it up in about 30 seconds. Thank you.

MR. PETERSON: These mitigations include extensive market monitoring and with Demand Response fully participating in the markets, you may not have to have all the mitigation rules we currently have to try to deal with generation offers.

The 21st Century will see the full integration of demand with generation and transmission resources, to produce unprecedented flexibility and the ability of the system operators to maintain system balance. That is one of the true benefits of Demand Response and why it is so critical that the Commission get the rule corrected this instance.

Again, I thank the Commission and staff for the opportunity, and look forward to your questions.

MR. HUNTER: All right. Thank you. Next up Stephen Sunderhauf from PEPCO.

MR. SUNDERHAUF: Good morning, Mr. Chairman and Commissioners and FERC staff. Thank you for the opportunity to speak to you today on behalf of PEPCO Holdings, Inc. PHI brings a unique perspective to this conference. We own and operate three electric distribution companies, the Potomac Electric Power Company, the Delmarva Power and Light Company, and the Atlantic City Electric Company.

Together these companies serve approximately 1.9 million customers in our four jurisdictions, with a combined zonal peak load in excess of 13,000 megawatts. All PHI distribution companies operate with the PJM Regional Transmission Organization, and are regulated by the Delaware, District of Columbia, Maryland and New Jersey commissions.

Electric generation is deregulated in each of our jurisdictions, and our customers have a choice of suppliers. PHI no longer owns generation resources. PHI distribution companies have offered an array of demand side management programs over the past years, and our current status of utility-provided programs varies by jurisdiction.

At this time, we are moving to deploy advanced metering infrastructure in our Delaware, District of Columbia and Maryland markets, and we believe that deployment of the Smart Grid technology will strongly support increased Demand Response initiatives, including the introduction of dynamically priced electricity.

PHI offers the following comments of Demand

Response compensation. PHI supports FERC policy which encourages reliable Demand Response activities that are fairly compensated. There are several core issues to be addressed in the development and application of a national policy in this area.

First, financial incentives for DR programs should be market-based. Second, in reviewing DR financial incentives, all revenue sources should be considered. For example, in the PJM market, there are three revenue sources potentially, energy, capacity and ancillary services.

Third, if DR financial subsidies are established, a transparent Net Benefits test should be established and applied. Traditional utility DSM tests should be looked to for guidance for the design of those tests. Four, the development of DR market standards should be undertaken with explicit examination of the impact of these program standards on the reliability of RTOs.

Fifth, national policy on DR should recognize regional differences in electricity markets. Sixth, DR costs should be assigned fairly across market participants, and seven, regardless of the manner that DR costs are assigned, electricity consumers will bear the ultimate costs of DR initiatives, and therefore the electricity cost impact of national DR policy must be carefully considered before these policies are put in place.

We do not believe that a load response program which pays full energy locational marginal price for load reductions at every hour will necessarily result in the optimal level of load response. In general, DR programs should be market-based, and incentives for load response programs above market prices should be limited to extreme conditions, for example, to mitigate high market prices and to provide additional resources when electricity supply is scarce.

Paying full LMP for load reductions at any hour and without respect to wholesale energy market conditions is likely to result in excess incentives for DR, since the total compensation to DR participants could exceed the market determined value of electricity. We believe that if DR subsidies are established, that a Net Benefits test should be created.

The Net Benefits test should be transparent, established up front and be readily understandable to all electricity market participants. In general, the principle decision criteria for a Net Benefits test should be that incentives above market-based financial revenue streams produce market benefits at least equal to the incremental costs.

Incentives that exceed benefits will results in resistance to Demand Response programs among consumer groups, and thereby undercutting the long run support for these programs. Finally over time, DR subsidies may distort the optimal mix of demand and supply resources in the market.

PHI believes that FERC should not promulgate one set of rules for load response compensation for all RTOs. Each respective RTO is uniquely situated with its own set of operating rules, unique load shapes, different generation mixes and a variety of specific load conditions.

It is also important to note that individual state DR policies will differ. However, it is important that similar Demand Response market design principles be applied across the RTOs, to avoid the unintended effect of shifting available supply or demand resources across adjacent RTOs, simply due to differences in philosophy.

In conclusion, PHI supports policy initiatives to foster greater participation in DR, and the development of new programs, as evidenced by its sponsorship of a wide array of DR programs for retail customers over many years. Looking forward, market-based policies that fairly incent existing and new forms of DR, and assign costs appropriately, will help to ensure that the appropriate mix of demand and supply resources are available.

Once again, thank you for the opportunity to speak to you today, and we look forward to your questions and our continuing participation in the development of a national policy. Thank you.

MR. HUNTER: All right. Thank you, and finally we've got Dr. Roy Shanker, a consultant for the PJM Power Providers Group.

DR. SHANKER: Thank you, David.

MR. HUNTER: You're welcome.

DR. SHANKER: I'd like to thank staff and the Commissioners for having me today. I've been asked by the PJM power providers to comment on the two issues for today that the Commission identified, Net Benefits and Cost Allocations, particularly Net Benefits in this panel. As usual, these comments are my own and do not necessarily represent the opinions or positions of the people sponsoring me today.

I have to say that I find the two topics of today's technical session a bit perplexing, as they appear to assume away much of the substance of the Commission's initial inquiry and seem to have been based on the pursuit and the selection of what I see as the wrong answer.

If the Commission adopts the appropriate non-discriminatory pricing for Demand Response, and payment of LMP minus the retail rate in the context of customers that face a fixed retail rate, then there is no need for a Net Benefits test.

The LSE pays the customer the difference between the LMP and the customer's retail rate, and the customer receives the difference between LMP and what they would have paid under their rate, which is their net benefit. Therefore, there's no need for any additional test or calculation.

Similarly, under such compensation, there is no need for any subjective cost allocation. The financial consequences all fall to both the LSE and the conserving customer. There are no transfers from other parties and thus no other costs to allocate.

Considering these two facts from my perspective, the entire discussion today is based on proposed solutions that fall out of the wrong answer to the initial question. Further, this question or this discussion regarding the nature of the proposed Net Benefits criteria is troubling in and of itself, as it explicitly incorporates consideration of portfolio effects caused by the reduced demand on all load payments, versus the economic decision-making of individual market participants pursuing their own legitimate business purposes.

This appears to coordinate the very type of market behavior that would be totally unacceptable if engaged in by suppliers. The best way to see this is to indulge in a slightly rhetorical analogy.

Assume there was a meeting of an electric supplier group representing 150 megawatts of capacity in PJM. They notice that the independent market monitor has commented that a shift of two and a half percent of demand, approximately 3750 megawatts in the PJM capacity auction, changes payments to suppliers by approximately $2 billion.

Assuming the same impact for a reduction in supply, they decide to identify the 3750 megawatts of existing generation that has the lowest net operating margins. They discover that the worse-performing 3750 only nets $1,000 a megawatt year, or $3,750,000. They conclude that this is a wonderful opportunity to improve the economics of the group by $2 billion if they pay the 3750 to retire, physically withhold the generation.

However, immediately there are problems. The owners of the 3750 want more than $1,000 per megawatt year, and the remaining suppliers are arguing among themselves how to divide up the $2 billion. So they decide to petition the Commission for guidance on the best criteria to reduce supply, while maintaining an efficient, reliable generation fleet.

They also ask for guidance on how to allocate the increased revenues among suppliers. My suspicion is rather than holding a technical conference, most discussions with the Commission might instead address whether or not the suppliers could negotiate for adjoining jail cells while they continue their discussions.

(Laughter.)

DR. SHANKER: Yet facetious as this sounds, upon consideration it's not any different from what's being discussed today. Collectively, parties are negotiating on payments in excess of what is economically efficient to drive down demand and price, and justifying it based on portfolio effects to be received by buyers collectively, via the reduced market price.

They're asking for guidance on the optimal decision-making and structure for this price-suppressing portfolio effect, as well as guidance on the distribution of the costs associated with the otherwise uneconomic decisions.

This is exactly the type of behavior that is continually monitored for and stopped when observed in supplier actions, and based on Commission precedent and capacity markets and elsewhere as mentioned by Joel earlier, this is also frowned upon in terms of purchasers' behavior. These types of actions contain all the elements of the exercise of market power by buyers.

With the above in mind, my short responses to the Commission's questions regarding Net Benefits are first, should the Commission adopt the Net Benefits test. I believe that from the above, it's clear that beyond getting the price right, LMP minus the retail rate, and actual LMP if at all possible for the price to be paid directly, the Commission should not adopt any further benefits test.

This in turn answers the second question regarding how to define benefits. That is, that the right benefits are revealed by the right price. The payment in this case for a fixed price retail customer by the LSE of LMP minus the retail rate.

Similarly, there's no need to consider other costs of demand responders, as they will make their own decisions regarding participation, based on the right pricing. In turn, there's no problem with identifying the beneficiaries as the participants in any approved program that verify their actual reduction in demand.

The fifth question, whether a common Net Benefits methodology should be adopted is also clear. The common generic compensation should be the LMP minus the retail rate for the customers that fall into the fixed payment class.

Finally, there is no need to address a benefits special. The full benefit, when manifest, is a payment of the right price, should always be available to the demand responder. It is only in the presence of discriminatory subsidies that creates the potential negative benefits by actually increasing total costs for customers, when subsidies exceed the aggregate price reductions. This concludes my remarks.

MR. HUNTER: All right, thanks Roy. Thanks to the whole panel for all their comments. So I'd like to open it up for discussion now. I had a few questions in mind, but I think Roy's analogy leaps to the front. I'd like to get the reaction of the--especially from the middle of the table, the people on the full LMP Demand Response supporters, and maybe try to explain from--I'd like to hear from your perspective how--and Audrey's, you can put your placard up if you want, how from your perspective maybe Roy's analogy doesn't apply on the demand side, if that's what you think.

Also, of course, the Commissioners have many questions they want to throw out there at any time.

(Laughter.)

MR. HUNTER: But I think Don Sipe's ready to talk. Please, go ahead.

MR. SIPE: All right. Pretty much the Commission dispatches the entire market based on portfolio effects. The whole idea of doing a bid stack is to get the cheapest mix of resources. So that's not a surprise, that that would be the--that would be what the market does.

Generators don't get to manipulate prices simply because we have a bid stack. They have a market monitor that will look at that. All's we're suggesting is that you put DR into the bid stack. I understand that the position of Pareto optimality is that you don't do this simply to lower prices to consumers.

We do disagree with that. That disagreement doesn't amount to a market violation, and I don't really think the Commission should take seriously those types of allegations against its proposal.

MR. HUNTER: Thank you. Audrey?

MS. ZIBELMAN: I think you should go to Paul first.

MR. HUNTER: Okay. Okay Paul, go ahead please.

MR. PETERSON: I was going to try not to be repetitive, so I'll just address one aspect of, I think, this issue, which is the issue of externalities. A couple of commentators talked about economic efficiency. I don't know how to define "economic efficiency." I don't think anyone in this room can produce a definition that will satisfy everyone in this room.

So I think what we're left with is we don't look at things external, and in that respect you shouldn't be looking at what some Demand Response provider may or may not be doing behind their own meter or with their own business, or why they're offering it at a particular price, as long as they're willing to offer a resource at a particular price.

It should go into the bid stack and then we'll see how it falls out.

Now the externalities that people like to refer to are selective. So if you want to figure a way to disallow Demand Response participation, we'll talk about externalities like the retail rate. But if we're going to start talking about one externality, we should talk about all externalities. We should talk about the subsidies that exist, a lot of existing generation resources, and we should go back and look at which generation resources have received cost of service payments for the last 10 or 20 years, before going into competitive wholesale markets, and make sure that those costs are reflected in whatever they're bidding as well.

We don't do that, and there's very good reasons why we don't, that it gets very complex and it's too hard to do. So I don't think you can selectively select one externality such as the retail rate and say that has to be part of the consideration here, and ignore all the other externalities.

The proposal I made, and I think consistent with the folks to my right here in the center of the panel, is let the Demand Response providers offer at the price they want to offer, and give them a way to get into the bid stack. Let them compete with generation and develop the optimal set of resources.

MR. HUNTER: Thanks. Audrey. Go ahead, Audrey.

MS. ZIBELMAN: Actually, I think this was--it was well said. So the two things that the markets don't do and regulators don't do very well are pick winners and losers. The markets pick it by the LMP pricing, and so we shouldn't be in a position where we're saying well, we want to favor one type of resource versus another.

The fact of the matter is is that we're talking about a grid. The grid has to stay in balance. The grid can stay in balance by megawatts coming off the grid, just as well as megawatts coming on. When it comes off, it has a tendency to reduce prices. So it becomes a lower-priced resource, exactly as Professor Kahn identified.

The second is, as Mr. Peterson said, we never have in the market looked at whether or not the profitability of a particular decision from the particular firm makes them deserve that they should get LMP or not. LMP's the price. That's what folks get. The economic consequence is that to the individual is predicated on their internal costs and assumptions, and may or may not win in every hour of the day.

There's lots of reasons why people bid in different prices. So you know, to go there, I think, would get us down the track of saying well what were the revenues that this particular generator got last year, and should we have. In fact, we've had these debates for a long time. Should we have two-bid prices. Should we have a base load bid, should we have a peaking bid, because the base load providers make too much money.

We've all discarded that. That's always been a bad mistake, and it would be the same thing now.

MR. HUNTER: Okay, thanks. Roy.

DR. SHANKER: Yes. I think there's a couple of things. First, I would probably agree with almost everything Audrey said, if the customer is paying LMP to begin with. But that's not what's happening. We have an enormous amount of load that is seeing a fixed price, and this comes back now is where we close the loop with what Don said, and where I strongly disagree, is that you can look at the fixed price retail arrangement as the LSE having sold a bunch of calls in the retail market.

You can look at the payment of LMP as opposed to LMP minus the strike price as overpaying or overcompensating a group of parties that hold the call position, by the amount of the call position in excess of what the market price is, in order to suppress price in another market, in the wholesale market, where those same parties are very long or I'm sorry, are very net short, have large net short positions.

If you read, Joel referred to the Amarenth and the ETP decisions, what I just described, manipulating price by overcompensation in one market where they have sold calls, to suppress price in another market where they are, have large short positions, reads like the introductions of the Enforcement staff to the Show Cause orders in those two cases.

And so it's not something that should be ignored. It should be a fundamental issue as to the decision-making of the Commission, as to whether or not you are going to overcompensate in one market to suppress prices elsewhere, and the portfolio effect of that suppression seems to be what everybody is talking about.

If there were no overcompensation, there wouldn't be any need for all these concerns about Net Benefits test and possibly losing money. It's inherent in what's going on. That's why we're discussing this.

MR. HUNTER: Just to clarify, when you talk about the portfolio effect, you're talking about the overall effect on --

DR. SHANKER: The over--yes. The Net Benefits calculations all seem to be predicated on how much does the rest of load save by the price dropping. That's what I meant by portfolio, as opposed to, you know, marginal clearing price. That was not--those two did get a little jumbled in some of the comments.

When I said "portfolio," I'm talking about the third party beneficiaries of a suppressed price, or in this case maybe the same party by doing it, by overpaying for buying out their call positions in the retail markets.

MR. HUNTER: And just for those of us who aren't finance majors, explain again the argument that it's effectively a call option?

DR. SHANKER: Okay. We're talking--as I said, I agree on an LMP customer, someone who pays LMP at retail or something close to LMP. We're fine, because LMP minus retail rate turns out to be zero, and they just see the LMP. Then I agree with everything Audrey said. But let's say from PEPCO, from PDS I would get an $100 a megawatt hour price.

I have the right to execute that. That's me and my home, at when LMP could be $200 or $300. So PEPCO, as the LSE, has to go out and buy from the market, let's say at $300, but I only--I have the call on them at 100. So they're going to lose $200, okay. What we're talking about in the correct compensation is essentially them being held neutral and giving me $200, okay.

They're going to lose $200 one way or the other. So they either buy it out of the market and they convince me not to consume. So they give me $200, which what they would have paid. I would have given them 100; they would have given another 200 to PJM and bought the $300 energy.

If alternatively they gave me 200 and I don't consume, everybody's in the exact same position. But let's say they give me $300, and you say well, why would they do that? That's what's being discussed here today, is giving me 300 instead of 200. We start to look and they say well, if I give enough of you 300, I know it's too much money. That's why you're concerned with overpayment, and in driving the net benefit negative.

But if I give enough of you $300, particularly when prices are very high, aggregate demand will drop from 300 to say 200, and the other 100,000 megawatts of load in PJM all say it's $100. So it was worth it. Part of that other 100,000 might have been positions held by PES. So we're concerned directly when people sit down and say a lot of us are short in the wholesale market.

If we overpay people in retail to drive their consumption down, it's going to give us a net benefit on the wholesale side of reducing prices. Now it sounds good in general for consumers, but really the transfer here is going through the LSE. It may go to the consumer; it may not. Mr. Ott mentioned that he didn't know who's hedged. If everybody were hedged and that happened, the entire benefit of this would go to the LSEs. None would go to the retail customer.

MR. HUNTER: Any of you had it up there? I may have called you out.

MR. OTT: Yes. I was going to try to help, but I think--let me--the key is that comparability. In other words, absolutely every megawatts injected or every megawatt not consumed should be paid LMP at the wholesale level. We aren't debating though.

When I pay the generator LMP to bring that energy in, they had to buy a forward fuel contract or they had to buy something to give me the energy. Nobody's discussing--in other words, their net profit, if you will, has to do with what they had to purchase on a forward basis, whether it be fuel or energy, and then sell it in that wholesale.

On the retail, I mean on the demand side, if somebody bought a forward contract to pursue them out on the exchange to consume, and they brought it into our market and then they decided hey, I'm not going to buy from that market because effectively, you know, I could make some money here. So they essentially don't buy, take that money and they made money on their forward contract, okay.

Basically implicit in this, because we have the retail side of this, the right to consume does--it not priced at zero. They had--somebody has to pay money, and that's the fixed retail rate. If you ignore the fixed retail rate, it's like ignoring, you know, the generators, you know, fundamental cost. I think that's what they're trying to say. I'm trying to put it in different words. But that's effectively the differential, I think, that Roy was trying to explain and I was trying to come from a different point of view.

MR. HUNTER: All right, thanks. Joel, you had yours up?

MR. NEWTON: Thank you. I guess coming from a slightly different way, and just focusing on the call option that we've been discussing, when we look at this, you know, it was very interesting listening to Don's earlier remarks, because he agreed, and as did Professor Kahn, that we are dealing with the call option, and the question then is who is it between?

I think as Andy was just saying, the call option is really between the LSE and the consumer. What's being proposed then by Professor Kahn then is that the consumer then has the right to sell its option, without having to do anything about the strike price that it agreed to enter into to the ISOs.

That's really what his theory, the entire theory is, as to why they should be able to be paid the entire LMP and ignore the LSE all together. What we're saying is that actually the LSE is very important here, that the agreement by the consumer was to pay the strike price, and that is the retail rate to the LSE.

The Commission is getting into a real close area with retail ratemaking as we go through this entire process. For the Commission then to say "ignore the LSE payment," which really is the realm of state commissions, it's almost as though you're just hoping that the state commissions will go out and fix it.

The state commissions can do that. They can go out and individually say we're going to handle this differently. But the proper thing to do now is to get the price right at the outset. Now in Amarenth, the Commission Enforcement staff noted the fact that, you know, the job of the Commission is to police the behavior of markets, and its interest isn't simply in one side of the market, the consumer, but also the seller side.

My real concern as we're going through this entire process and listening to many of the different panelists is that the goal here seems to be to focus on the one side, with the Net Benefits test being the consumer side. We need to make sure that this market works, and I think that what a lot of panelists are now saying is that we need to look at the retail rate as part of the overall product that's being sold and purchased.

MR. HUNTER: Okay, thanks. Before I get to Audrey and Don, since we brought up retail rates, John's got his card up, something to say.

MR. KEENE: Yes. I just think I have two points in response to this concept of the call option and being required to buy that ahead of time. I think first of all, I think it's inherent in the regulatory compact that already exists with the local utility, has an obligation to serve.

So those end use customers already have that call option, and they were given it by the regulatory compact. They already own it and own it for free. They should not have to pay anything further to have it to call upon. So that's my first point.

The second point is this whole debate is really circling around the compensation issue rather than that benefits test. But you know, as we addressed in our initial comments, whether you have to buy the LMP ahead of time or whether you only pay LMP minus G, that's theoretically the efficient price. That's right.

But it's not enough to overcome the well-documented market barriers that are known to exist, whether they be technological, political and so forth. So if we're going to overcome those barriers and get a level of Demand Response that is closer to the optimum that would exist in a truly price-responsive market at all levels, then we need to pay the full LMP, and we believe that's the appropriate price to pay. Thank you.

MR. HUNTER: Thank you. Audrey's had her card up for a while.

MS. ZIBELMAN: If people want to move on to other questions, I'm more than happy--I think this is something we could probably write off. But I would just say that just to add to another perspective on this, we are, as part of a number of our clients, are actually working with load-serving entities as well as generators and people are looking at this, because frankly the utility industry's always recognized there's a lot of optionality in load versus generation.

That's why utilities offer DR programs. Many times they paid at retail and then resold it at wholesale. So now we're just allowing customers actually to get the full monetization benefits, rather than just the distribution utilities getting it.

And you know, one of the things that I've observed on the markets is that the first thing is for the Commission to get the--for us to get the price right, and the price is LMP. Then the second thing that will happen is as we see more and more Demand Response in the market hopefully, more and more customers participating in the day-ahead and real-time, then the contracts between them and the

LSEs will start to evolve to embrace how this will result in a much better hedge on the markets.

So the suggestion that somehow or another we have to protect load-serving entities, because they're not quite sure how to manage a price structure, because you now have the demand, I think, is somewhat naive. They'll figure it out. They figured out everything else. The issue is is first to get the market developed; then the structures, whether they're long-term hedges, etcetera, will develop around that.

MR. HUNTER: Okay, thanks. I think we may revisit this, but I think I will move to a more--away from this theoretical argument to a little more practical question.

Really for Bob and Andy, Paul described kind of a dynamic mechanism for running a--criteria selection for running a Net Benefits test, and evaluating demand side bids in full perspective of how they, you know, what their minimum, the equivalent of a minimum run time, those types of things.

First, how are you evaluating demand side bids now, and secondly, would it be possible or how would it work in PJM or ISO New England for kind of dynamic tests like that like they described?

DR. ETHIER: Well first let me turn my mic on.

First, let's--there's been a lot of talk about Net Benefits test, and I think the time scales of those have been not always consistent. So what I'm imagining you're asking is if we were to do on an hourly basis a Net Benefits test. Is that a correct presumption?

Okay, and the second one is, what I'm presuming for this question is the net benefit test is the effect on LMPs, versus the cost to dispatch the demand resource. Is that also correct?

MR. HUNTER: Correct.

DR. ETHIER: Okay. So it's not the net benefit test the way I advocated for it in my opening statement. Okay. So once we've got those two things nailed down, because it's important, because people are talking about coming from very different vantage points, and it's really important to know the playing field on which you're discussing these things.

First of all, our analysis that we did shows that frankly there's really no point in doing the Net Benefits test under those conditions, because it's going to be past, if you accept that definition of Net Benefits, in the vast majority of hours. Our number was 7,600 hours a year out of 8760.

I agree with the points made earlier, that frankly that's far beyond what we, most of us would reasonably expect for folks to want to participate in the market actively, put aside energy efficiency. So if you think that's already much more permissive than folks are going to want to participate in the market, then what's the point of implementing a Net Benefits test of that nature, one.

Two, I think the probably more constraining thing that nobody's really talked about today is baselines. The sort of the way that we measure reductions in consumption is relative to a baseline.

We have done a lot of work in New England on baselines, and what the numbers show in New England is to get a baseline that has some integrity to it, it looks like you really can't have people participating more than roughly ten percent of the hours in the year, because then you get long stretches of time where the baseline basically never gets updated, because you can't update it when they're actually reducing demand.

So to us in New England, the much more constraining issue is the customer baseline issue. It's more constraining than the Net Benefits test, based on our work. So those are two things. The third is if you actually get into the details of how you would do it, it also becomes then very complicated, and requires essentially an iterative process, and let me walk you very briefly through how that, at least in our view, how that would have to work.

First, what you would have to do is you would have to run your dispatch model to come up with a base LMP with no Demand Response. Then you'd have to re-run it with Demand Response in the market, and you'd look at the difference. Then you could come up--the problem is those two iterations alone don't sound so complicated, but they don't cover the whole waterfront in terms of the possibilities.

It could be that you're just dispatching too much Demand Response the first time, and if you truncate the amount, you would actually get Net Benefits in terms of reductions in LMPs. So if first you reject dispatching the DR, you may need to go back and dispatch smaller amounts of DR, and see what happens then.

And it's not really clear where you would stop that iteration. So in the actual implementation of this gets pretty thorny once you get into it. So really there's, you know, three issues. One is if you do it, our evidence shows that it's going to be very permissive and there's really--it begs the question of whether you want to bother.

Two, the baseline's more restrictive, and three, when you get into it, it's actually going to be quite complicated to implement, and it's not clear what the stopping rule is if you were to implement it.

MR. OTT: If I can just answer the other part of your question, which was how do you do it today? Effectively, the Demand Response today, in both the day-ahead and real-time market, are essentially they've put it off or they self-schedule, of course.

But if they're flexible, they would put in a net offer. A net offer is considered, you know, if it has restrictions, they can have min, I guess the opposite of a min down time, but a minimum time we can accept the Demand Response for mean number of hours. So they can do all of that similar to what a generator can do, and then we would consider that reduction as part of--it almost looks like implicit supply, and they would be cleared the same as the supply stack.

That type of thing, of course, can be done. It is done today. But if you would take it to the level that Bob was talking about, which was actually try to somehow do an iterative process to look at effects on market price, my opinion is that would be very costly and difficult to do, if we could even do it.

MR. HUNTER: Okay, thank you. Don Sipe has comments.

MR. SIPE: Yes. Obviously I agree with Bob about if you look at realistic levels of where this would make a different result, that one of my earlier points was that it's not sure that it's necessary if you accept that's the idea that it's a lot of hours.

I also agree that there are baseline issues which are going to limit dispatch, plus there's just the incentable customers that are reasonably in it.

We made all these points in our initial filing, when we argued that, you know, a lot of the concerns about having DR dispatched, you know, when there's negative prices and things and we're going to--are a little bit overblown. There's going to be a natural limit to how much DR gets dispatched, based on those issues.

I think on the question of implementation, I think we used a heuristic device in our filing that show comparing dispatches. That isn't the way I would attempt to implement it, if I were going to implement it. It's much simpler to restate bids, and it's easy to restate bids just in the bid stack.

As you go up, you know each place where they are, and you know the effect that any resource after that is going to have an amount of missing money involved. You wouldn't run alternative dispatches, and you wouldn't do an iterative process in that way. You would simply restate the bids based on where you are in the bid stack in the price. You know the load, you know the other things. Those will stack up in order.

We did use the alternative dispatch as a heuristic device, just so people could see, you know, sort of the logic of the algorithms. Well, we wouldn't do a computer program that way. Now I'm not a computer programmer, but I can figure out how to restate these bids in each interval, in a way that means you just compare two bids as you go up the bid stack.

And you know, this is the level of detail that we're probably not going to get into on the panel, but I would not assume that that's a particularly difficult thing to do or requires comparing, you know, one dispatch against every other dispatch. I think you can do it just by restating bids, because the math is fairly simple to do each level, and it's fairly determinative. Thanks.

MR. HUNTER: Okay. Audrey.

MS. ZIBELMAN: Just very quickly on the baseline. I think the issue of baselining is a separate topic from here, but I wouldn't necessarily assume that that's itself a constraint. I mean one of the things that we're doing and part of the constraint is when you use historic average, historic baselines versus predictive.

By moving towards predictive, however, we're able to actually put Demand Response and show how you could be in various hours based on price sensitivity, the same way we forecast load in the markets.

MR. HUNTER: Okay, thanks. Looking over to the Commissioners, any questions from the Commissioners at this time?

(No response.)

MR. HUNTER: Okay, all right. Well, I'm going to go Bob mentioned the measuring Net Benefits or defining Net Benefits, and we talked about, you know, the effect on the market clearing price. I'd like to ask anyone out there if, you know, are there other things we should, the Commission should be looking at when measuring the benefits, the quantifiable benefits of Demand Response. Go ahead.

MR. SIPE: We have generally been really reluctant to look at externalities when we try to decide how to do this, simply because, and I think it's been pointed out and I think correctly, that once you start doing that, you've really got to sort of take into account everything.

Certainly we can't do everything on an empirical basis, where we know there are externalities that we want to effect. You know, that can weigh in the decision where there is uncertainty, but I would just point out that there is great uncertainty in all these externalities, given the state of eternal markets.

None of them are Paretal-optimal anywhere around this market or within this market, for that instance. So we don't really have a way of determining whether we're doing more harm than good once we go there. I would point out some of the other externalities that were--I'm not sure whether they're externalities or not, but you know, some of the concerns about the capacity market, for instance.

I find it odd that Demand Response is any different than cheaper generation coming in and reducing energy prices. Just because it's a different type of resource, that's--it doesn't seem to me to pose any particular problem with a reduction in energy prices. To the extent that scarcity revenues are not sufficient, we have capacity markets that are designed to make sure that those capital costs are recovered.

To the extent that the actual operating costs of the units, the variable costs of units, price marginal costs are not compensated. Those savings go right back to the generator when they don't have to produce. So we have more than one market here, but the capacity market's designed to deliver the scarcity rents that our market doesn't.

If it does that efficiently and we think that it generally does, then I think that, you know, you don't have a problem with this any more than you do with lower price generation coming in. Finally, I do want to go back just for one second to something John Keene said. The option that consumers buy is not for free. The regulatory compact allows for things like capacity markets, and consumers pay for those.

The just and reasonable rate standard assures a certain amount of revenues to generators overall in the market. We don't know which one of them are going to get it or who's going to be efficient. But that is not free to consumers. We purchase that every time we purchase rates, every time we pay for RPM or any of these other capacity products. We buy that option. Being asked to buy it twice is a little odd.

Generators are trying to convert the obligation to serve into a right to compel service, and that is incorrect. They don't need to be paid twice for that option, and it's not overpayment when a consumer who has already paid for it, through the regulatory bargain, releases it.

So I think those are about the only externalities that we've really hit upon that I think are relevant. Thanks.

MR. HUNTER: Joel.

MR. NEWTON: Thank you. I think that, and as Don was just talking about, there are other markets that do need to be looked at, and probably the capacity market is an important one. Right now, we have demand really participating in two different ways.

One, it can participate directly, and is a competing resource. Secondly, with a lot of the energy efficiency programs, it simply takes off from ICR. Whether it competes directly or as a subtraction to the total installed capacity requirement is really meaningless from the total amount of capacity that the consumer is purchasing. It simply is who is it purchasing it from.

An interesting question I think that we are getting to is a comparability question. What we're getting at here is are we really looking at comparable products to start with, or should, for example, the DR participate more through--be reflected in the ICR, but participate more through the market mechanism, because of what its function is and how it seeks to participate.

I say that because we're looking at, and I believe Bob said this in his earlier remarks, at a point where we're having the pricing change in a way that may be unintended, if DR is receiving more and more money through the markets, which you know, I'm not saying that it shouldn't in any way. We of course state what we believe should be that payment, it will need less money through the capacity market in order to make up its entire price.

And indeed, they may be priced at zero at that point because if it's being paid a full LMP; it may be in the money at the very beginning. The other place where I'm somewhat troubled from a legal standpoint, and I've researched and I don't have an answer, is where we are with the Energy Connect case.

At this point, the Commission has stated that the product that is not being sold is really--it's a service, that DR is essentially a service and not a product. Yet when we're in the capacity market, we're talking about products. So we seem to be mixing and matching services and products in ways that I don't believe the Commission has fully taken into account at this point.

Finally, I think that as we're going into the various markets, it is important for us to look at the comparability issue in all different ways, and whether or not the payment structure is appropriate in one market versus the other should be looked at on a comparable basis. Thank you.

MR. HUNTER: So Andy's got his card up as well.

MR. OTT: Again, the two broad benefits of Demand Response, obviously market efficiency in bringing in resource that provide additional alternatives in the energy market is one benefit. Another benefit, of course, is the grid reliability benefit.

But I think if you look at the grid reliability benefit, you have the transmission planning processes; you have the capacity market that both capture that benefit. So the reliability benefit is really captured over there, and I haven't heard anybody discussing at this point in this context that, you know, the capacity payments, at least in PJM that are received by Demand Response, are essentially equivalent to what the generators receive.

I think over here we're talking about economic Demand Response compensation. So I think that's more the market efficiency side. So I think even though there are broader benefits in Demand Response in general, I think the real benefit you're targeting here is the economic Demand Response benefit, which is more related directly to the market outcome. Just try to put it in that context. Thanks.

MR. QUINN: Andy, can I follow up on that and something you said earlier? In your written statement, your spoken statement, you said something along the lines that on a monthly or seasonal basis, you could probably figure out kind of an aggregate net benefit or even economic efficiency basis, but that--you said that's not something you proposed in terms of developing a Net Benefits test for compensation, partly because of the hedging issue you discussed.

This kind of relates to something that Bob said as well. How could you develop a Net Benefits test if you wanted to look at something other than prices going down relative to the cost to Demand Response, and what would you layer into a test, a benefits test for how often you paid Demand Response to LMP, if you wanted to incorporate something like economic efficiency?

MR. OTT: Okay. So you're saying how would I develop the benefits test related to compensation?

MR. QUINN: Yes.

MR. OTT: Well, the challenge with doing a test, for instance, on an every five minute basis again is just the difficulty of actually running the market multiple times -- would make it expensive to implement.

So what we've tried to do to--and I think it would actually be a great thing to develop a standard reporting-type mechanism for developing, you know, ways to report what are the benefits during, for instance, particularly hot weeks and we've tried to do that sort of ad hoc.

But to actually do that more regularly I think is something that I would find useful. I think the market would find useful to make that transparent. So you could look over a specific operating period, whether it be a week, hopefully not down to the five minute level, but either daily, weekly, something like that, and analyze what the Demand Response action had done and what its impact was.

That's something that is attainable and certainly could be done without a lot of expense. But if you tried to take that then and say now tie it to compensation, then I think it would beg the question, you know, how do you attribute, you know, how do you attribute the compensation?

If you try to get down below, you know, the level of just an aggregate benefit, then I think it becomes extremely difficult to do, because then I'm running, I'm trying to evaluate, you know, where the benefit was delivered to or who it was delivered to. That was much more difficult.

So if I just stay at the aggregate level, during operating periods you'd look at both probably the economic response and the, you know, I would call it capacity-based response that came in, and run analyses over that period without it, and that would be a way to quantify it.

If you tried to look at only the economic side, you certainly could do that. But I think that would probably at least be beneficial to put out the capacity-based side also. Is that an answer?

MR. QUINN: Yes, I hope so.

MR. HUNTER: Bob?

DR. ETHIER: Two quick things. First, ISO New England I believe twice a year does send to the Commission an analysis like that we perform, based on our current day-ahead load response program, that measures a whole host of different, using a whole host of different metrics, the effects of demand resources participating in our market on LMP, on overall costs, on efficiency, things like that.

So we do send down a report just like that. Undoubtedly that will need to change, as our programs evolve over time. But hopefully that is useful to you all, and that certainly something that could be expanded if there are additional features that need to go into that.

Second, when you sort of hit on the area of cost allocation, and that's not--I got the impression it was okay maybe to bring that a little bit into this discussion, because we're only one panel.

I think there are some costs that can be allocated in ways that actually the folks who receive the costs don't mind receiving the costs, which is remarkably rare, at least in New England. So basically if you--and you know, let's put aside how much you pay. Let's even assume you pay the full LMP resources.

If you assign the LMP minus G portion back to the load-serving entity that's serving the customer, the fixed retail rate, that actually hedges them perfectly against levels of Demand Response. Interestingly, they actually voted within the New England stakeholder process, to have those costs assigned to them, the LMP minus G cost.

Now that still leaves the G costs, if you're paying full LMP. You know, that needs to be assigned somewhere as well. Our view on that is that if you assign that to the LSEs, they're going to have to hedge themselves and build in a risk premium into their bids for standard offer contracts. So you're probably better off assigning that cost to somebody like a transition owner, that can pass it through without a markup associated with it.

So just basically the G costs need to be recovered. Do it in the least distorted way possible, so that it doesn't impose any risks on the various parties who are passing it through. So that's sort of the second part of that answer.

MR. HUNTER: Roy's next. Thanks.

DR. SHANKER: A couple of things. You're getting down to the Net Benefits mechanics, assuming you go that way. It's not clear in the other two markets. I think it is transparent in PJM that you would, all other things equal, you would increase capacity prices, because energy and ancillary service margins would drop, and they're on a rolling historic average.

So they would straightforward--you would see, at least in the reference price for the auctions, you would see an increase in the capacity prices. So if you really want to do this kind of benefit, then you really should take a look through those energy savings. They go in one pocket and then they're going to start coming out on the capacity side in increased capacity prices.

And there still seems to be some confusion about this notion of the option, and I'd like to clarify that if I can, and maybe you're probably aware of other confusion. It's not the purchase of the option that we're saying is free or not free. I agree with Don's position, but that's not what the point is.

It's associated with the option is a strike price for the energy, and the retail customer has locked in, whether it was given to him or they paid for it. In that option, he's locked in an execution price. We're saying, and I think Dr. Hogan has the comment more generally; I say it in one line, is you've got to buy it before you can sell it.

So in this context, to make good on the option, to be able to possess the product that then goes back into the market, whether you paid for the option or not is irrelevant. But you do have to pay the strike price. That is the retail rate. So that part is inherent in the calculation, and that is why is Bob is saying I've got to worry about the G, you know.

The G is what's missing. The G is the missing money. It is the strike price. If it doesn't get paid, he has to find somebody else to foot the bill. And that's, we're trying to separate that from the cost of the option itself. We're trying to talk about the strike price of the option.

MR. HUNTER: I think has been waiting. Don, go ahead.

MR. SIPE: A couple of points. Let me go back to the option. Actually, what you're selling is the option. You're not selling the energy. So you know, it's the sales price of the option, not the energy. So you don't have to purchase the energy you're not going to purchase in order to sell it. I think that's a little circular.

But going back to the allocation, even though that's not this panel, we believe that stuff should be allocated to the day-ahead market in the energy price, because that gets to the people that benefit, by purchasing DR. That's where it ought to be. It ought to be just rolled into the day-ahead price, and whether or not there's a benefits test or not, you always know how much DR there is.

So you can always figure out what the billing unit impacts are day-ahead. You always know what that price will be, with or without a benefits test. You can put it right in the energy price. It could be transparent to the market at the time consumption decisions are made. Once you do that, you also have the revenues that you need to solve them issuing money problem later, and solve the problems that I think Roy's legitimately worried about, about compensating LSEs whose load is affected by DR.

That's explained in our allocation portion. But in terms of getting it there in the first place, the place for this stuff to be is in the price of the energy, so that consumers see the marginal cost, what it's really costing them at the time of consumption. From there, it's very simple to satisfy the LSEs' legitimate concerns that they not be left holding the bag without an ability to settle for resources, and we explain that in some detail in our paper.

So to Bob's point about the allocation, we think whether or not there's a benefits test is a very simple and straightforward way to allocate these costs, simply by rolling them into the energy price, particularly dealing with day-ahead.

We do not deal with real-time, five minute dispatch intervals, because I think there's problems with the ability of DR to respond at five minute intervals and bid and things that sort of overpower the mathematical question, whether you can settle efficiently, and there's no missing money in real time. So I'm not sure that that elaboration is needed. Thank you.

MR. HUNTER: Paul, you had something you wanted to say on this, I think.

MR. PETERSON: I wanted to address Roy's comment, because Roy and I don't often agree on things. But I agree with something he said, so I think it's worth commenting on.

(Laughter.)

MR. PETERSON: Roy commented that if you had Demand Response participating, I'm not sure if he used this word, but intra-marginal rents would probably go down, and you might see an increase in capacity prices for resources that need to recover the capacity market, but they can no longer recover in the energy market. I think that's what he said.

That is probably logical, and that may not be a bad thing, and the reason it may not be a bad thing is we currently are meeting our electric needs with capacity factors of somewhere around 60 or 65 percent in a good area, and in New England it's down to 55 percent and heading to 53 percent.

What a 53 percent capacity utilization means is that half the time the generation fleet isn't producing anything. They're still paying the mortgage; they still have all their fixed costs, and they need to recover those costs. They can recover them in the energy market when there are price spikes and they collect intra-marginal rents, or they can try to recover them in the capacity market.

If you have a lot of DR participating, I don't think anyone here disagrees that energy prices on average will be lower. Energy prices will not be as volatile. You will not have spikes in prices because you won't have spikes in demand. The demand will drop off the system as prices go up.

So you end up with prices that fluctuate between 50 dollars and 100 dollars all year long, rather than prices that fluctuate between 50 dollars and occasionally 150 or 200 dollars or 500 dollars. It's the dampening effect that Demand Response would have. It's a disciplining effect on other bids in the marketplace, and if they can't recover intra-marginal rents in the energy market, they're going to have to raise the capacity bids in the capacity market, and some generation won't clear.

So we will attrition the generation fleet, because we don't need all of these generation resources that run half the time; we could use two-thirds of them and run them two-thirds of the time. That, I think, is one of the big benefits of including robust Demand Response participation in the markets.

That, I think, is where this Commission wants to get to, and the question before this panel is what are the mechanisms we can put in place, I think, to try to transition to that future.

MR. HUNTER: Thank you. Stephen, I saw your card.

MR. SUNDERHAUF: Yes. I wanted to offer a couple of comments related to the Net Benefits test, and that is clearly the energy market and the capacity market are going to affect one another. So it's clearly the case that we establish a Net Benefits test, that both of those markets need to be taken into consideration.

The third item I wanted to add was this concept of reliability in the long run; reliability, if we have generation supply exiting the market because of additional DR. We do need to look at the long run reliability impact of that DR resource shift. So I would add that, urge that that be taken into consideration, that test as well.

MR. PECHMAN: How would you propose to do that?

MR. SUNDERHAUF: Yes. One of the concerns about DR is its permanence, whether it's there for the long run, whether it's accountable and reliable, and as we introduce new pricing, particularly as we introduce dynamic pricing and AMI-enabled dynamic pricing, some of that load will automatically respond to price.

Over time, other customers will basically change their method of doing, putting more energy efficiency in place, doing things more efficiently. So the question is how much DR is really going to be there long run when you really need it, and really the concern over time is if you have, you know, a certain level of DR, is it sufficient to ensure that the market is reliable when called upon.

So you get into those 100 degree days that we had this summer in the Washington area, and is it accountable when called upon, or is it something there that's there in the month of July but not necessarily the month of August. So we have those kinds of concerns.

MR. HUNTER: Audrey has a response.

MS. ZIBELMAN: Thank you. I actually wanted to address the reliability issue, and I think there's a couple of things. One is I--there is the issue of long-term reliability in terms of when we have additional load response in the market, one of the effects we're going to have is sort of a flattening of the curve.

So you have a long-run efficiency gain, which gets to the point, which is I don't, I think what will happen is you'll have excess capacity in the market able to retire, because you'll have less peakiness in the load itself.

The second piece that you're going to have is that with additional resources, you're going to have some load shifting, from the morning hours into the evening and night hours, which could be particularly beneficial when you have wind generation, since as we all know that wind blows during, more at night than it does during the afternoon.

So by pushing load into the night hours, by using storage devices, you're going to have efficiency gains around that, and maybe avoid some of the negative LMPs that we see in some of the markets, because there's more wind in nuclear and not enough load. The other thing is that you have short-term operational efficiencies. One of the problems you have, and this is a big issue around the world with a lot more deployment of distributed energy resources, if they're not cooptimized with the market, then the distribution company and the transmission grid has to worry about when those resources are going on and off. They don't have the transparency.

So one of the issues of the very large power grid operators group that's looking at this issue is how do you coordinate the operation of distributed energy resources and storage with generation on the market. By integrating into the real time dispatch, you actually allow for more cooptimization of these resources.

There's greater transparency, and now you can start using these resources not only for energy, but also reserve markets and reactive markets, and create what the Smart Grid talks about, is self-balancing networks. So actually rather than detracting from operational reliability or long-term reliability, the fact is it will extend it.

But the other thing that I think we tend to think in this industry always in terms of well, the industry knows best. The fact is is that you work with customers, they're incredibly concerned about reliability. That's why they're investing in this, because they're really worried about having, not having 100 percent reliability on their system.

I think if you compensate folks and I remember we used to say this when the independent power industry got started, oh, these guys won't be on, because you know, they're not utilities, and only utilities worry about reliability. The fact is is that the compensation is right, they are going to be in the market, because it will become part of what they do. It becomes an asset.

So I think these are sort of scare targets, but really unrealistic from where we'll go.

MR. HUNTER: I know Robert's got--Robert, go ahead. Thanks.

MR. WEISHAAR: Yes. I want to close the loop on this capacity issue. I don't want the Commission to walk away from here saying if you provide--or thinking if you provide full LMP compensation for Demand Response, you're going to get a corresponding increase in capacity prices.

It's much more complex than simply looking at an EAS offset as part of the RPM mechanism and PJM. To Audrey's point, properly compensating Demand Response should flatten load profile, should decrease forecast of load projections. As we've seen, decreases in load forecast have powerful reductions in RPM clearing prices. So the answer is not as straightforward as just looking at the EAS offset.

MR. PECHMAN: Roy, I have a question for you. You've talked about the interrelationship between the DR compensation and the capacity prices. Have you done any empirical analysis to provide bounds on what you expect the impact would be on the capacity prices, or is this just--this is the direction you expect it to move in?

DR. SHANKER: No. When you're--the answer is any empirical work--to clarify what Bob is saying, there are more things going on. But if, and it's not--I mean somehow the notion of looking for the right price that might be a little lower than somebody else's view of the right price, is being translated into DR is awful and you shouldn't do it.

That's not what's going on here. I mean I'd love to see higher penetrations of real Demand Response. I'd prefer to see it formed as price responsive demand systems like Audrey is talking about are wonderful. I represent people who are doing things like that.

But the issue is you want to get the price right. Part of the impact here will be in doing all these things, it will change the average prices. In the energy markets, we'll probably--in the capacity markets, we will see the unit price of capacity go up. We may need less capacity. That may be a benefit on the other side. It has to get netted out.

When you're doing something, when you're sitting in the role of saying I want to change the price artificially, at least from my view artificially, you've got to track these things. If you want to say just put all the customers on LMP and pass it through and they decide, okay.

So they pay LMP for their retail rate. They don't have a call other than at LMP. Then you can close your eyes to all this and not worry about it. Or if you're going to still have fixed rate customers, you've got to compensate for that call option we're talking about. I mean but it's not saying not to do it; it's just saying to do the right amount of it.

It will, and it will--it may go up. The unit price absolutely, I think, goes up in the PJM capacity markets. We probably do have, we do have information on that, I guess. You know, I suppose we could get information on that.

But the aggregate amount, I don't know that you would know whether or not it would, you know, could encourage more penetration by DR as a capacity resource in emergency programs or the capacity programs, in which case the total price might go down. The total amount might go down, but the price might go up.

MR. HUNTER: Okay, thanks. Don's had his card up for a while on the same point.

MR. SIPE: I think whether the price goes down or up, you know, whether you recovered in the energy market, the scarcity is eventually recovered through capacity, I mean we have an EAS adjustment in PJM that I think is not well designed to do what it's supposed to do. But it's still, the theory is that we get the money back.

But I think the reliability concerns always strike me as sort of a collateral attack on the structure of the capacity markets as they are anyway. I mean we've got availability adjustments for people that don't perform, which if DR is not performing, the value that you give to that capacity is going to be taken down.

We've got a forward market that looks ahead as load adjusts, and you can see whether the people are performing or not. Long run reliability, as long as you are paying an amount that is necessary to induce new investment and reflects that market value, the argument that because there's DR in the bid stack, generators are going to be out of it.

Well, they'll only be out of it if they're higher priced than the consumer resources that are brought by DR. If they're higher priced, that means that the consumer resources are going to be there, as Audrey points out. So we have this trust in this RPM market for capacity, as long as we're only paying generators, but we don't trust the same adjustment price when it comes to other resources.

I find that rather odd. I think that the availability adjustments for DR performance will be sufficient to make sure that the proper value for those resources is there, and if they aren't there in July, they'll be penalized in July and the amount of capacity you buy from that resource is going to go down.

As that changes over time, that will change over time. The bid stack will change over time. I agree we'll have a different mix of resource. I agree completely with Paul. It will be a much more efficient mix of resources. But I don't really believe there's a legitimate reliability issues unless there is something wrong with the capacity market for generation itself.

MR. HUNTER: Andy, it sounds like you've got a direct response.

MR. OTT: If I could throw in, obviously we have Demand Response in our capacity markets, our energy markets, our ancillary service markets. I have not observed one problem with them delivering when called. In other words, the ancillary service, the spinning reserve, they perform at least as well as the generators, if not better.

In the capacity market, we've seen when they are called in the period, the compliance period, they deliver. The tests have shown that; the actual impact market calls have done that. Even off cycle we've gotten Demand Response to come in and save the day, so to speak.

So from a reliability perspective, at least I haven't observed it. There's been a few bad actors over the years in the economic side, where we've had some issues. But certainly those have gone away. As Audrey said, we're actually in the middle, and in PJM we're going to have it by next summer, of deploying essentially a new dispatch that does, that can handle, distribute it down to the nodal level of both distributed resources.

So we can actually observe how the Demand Response would affect the dispatch and the transmission congestion on a nodal level. So I think the reliability side of this, the technology is fine.

I think it's really back to, you know, the incentives. You don't want to create an incentive for--for instance, state agencies or state entities to pull their DR out because they're experiencing cost shifts down at the retail level.

The real issue here I think on the compensation is not to create an unintended consequence, which will create unintended cost shifts, which would require some kind of--which would in turn produce a retraction. I don't think there's a reliability concern. I just am concerned that we're headed down a path that we don't need to head down, because we haven't seen it.

DR. ETHIER: Excuse me, I just wanted to echo Andy's comments about, you know, naturally resource response varies from resource to resource, and owner to owner, and that's true of generators and of Demand Response. But we haven't seen systematic problems, and I'm not actually sure how that got going in this discussion actually.

MS. SIMLER: Actually, I'd like to use that as an opportunity to return to the Net Benefits issue, and I have a question for Mr. Sipe. Actually, I've heard in comments from Mr. Weishaar and from Audrey, there was statements made about load-shifting and/or trying to capture a benefits of Demand Response over longer periods of time, rather than just, you know, in the intervals in the day-ahead market.

How does your proposal--how would your proposal account for benefits that accrue from load shift and/or benefits of DR that would be over, I think someone said, even a weekly time frame?

MR. SIPE: Well, the algorithms as presented are basically agnostic as of the time period in which they're applied. You do not have to apply it in a five minute interval, in an hour interval. You can sum intervals, and it will be compatible with any optimization you choose. You can choose to take the sum that optimizes prices in a day, for instance, and if someone has a minimum run time of four hours and it doesn't clear in one hour, you can still accept it in that hour. The algorithm doesn't tell you what you have to dispatch; it simply gives you the information on cost of dispatch in that hour.

So that algorithm in any time interval, if you want to do it in five minute increments you can do it and sum them over a day and come up with the lowest cost dispatch. If you want to do it in hours, you can take the sum of the hours that's the lowest cost dispatch. I'm not a settlement guru, but there's nothing within the procedure itself that requires you, for instance, to reject a bid that doesn't lower in a particular interval.

You can look at a four hour interval and see if it lowers overall price. But you have the information there to do it. It will spit out the results and allow you to do the optimization.

MS. SIMLER: Do we have--I'm assuming this is going to require some history to be able to do this from a DR perspective. Do the RTOs have information available to be able to--if you were going to look over some period of time, and to be able to price it accurately and timely, I'm not quite getting how we can take Mr. Sipe's proposal and accomplish that timely, if you need to look over a longer horizon time frame.

If you need to consider what Demand Response did over a longer period, but you're confined to looking at the impact in the day-ahead market, how do we do that? Either I'm not getting it or there's a disconnect for me somewhere.

MR. SIPE: Are you asking if you can--once you have your results in the day-ahead market, you can sum over long periods. Are you looking for a test --

MS. SIMLER: But then aren't you settling after the fact then, I mean far after?

MR. SIPE: Well, but if you're--are you looking for a test that determines in the hour whether LMPs are lower, in the day whether LMPs are lower overall? You're right. If you get completely beyond the day-ahead market, so that you can't settle it then, then you're correct. You could look back and analyze, I guess, you know, each day's result as you get results.

But the purpose of the algorithm is to allow you to settle in the day-ahead market, and to fully integrate in that time period. It's a benefits test within that time period of whatever, however you optimize that day. But I would think if you got the lowest cost in every day, that's what the algorithm would show you. You would not end up with a different result if you looked at 100 of the lowest cost days. But I may be missing your --

MS. ZIBELMAN: I think I understand your problem, and let me just try to restate it, because I don't think I have the solution either. Let's say that you have a proponent who's looking over a 24 hour period, and what they're looking to do is that there are certain hours where they're going to reduce their load, because prices are higher and certain hours are going to increase.

Now from the standpoint of a supplier, that's a great benefit, because if you're certainly baseload, you now have more load at the evening hours. If you were just look at that snapshot of reduction and say is there a net benefit, well that's hard to sell, because the fact of the matter is is that the supplier's getting more megawatt hours. Aren't they better off, because then they have a higher capacity factor.

In the end, they may be able to reduce their price even further because they're able to collect over more hours at a higher LMP than they would have, because there are night time hours that they're seeing negative LMPs.

So the point is it's not just simply looking at reducing price in an hour. The point is putting more load in the market, is you get a much more efficient load profile, which means you get a much more efficient grid, which in the end over both the short run and long run, you're looking at lower prices.

MS. SIMLER: Thanks for reading my mind.

MS. ZIBELMAN: That's what I would be concerned about as well.

MS. SIMLER: So any ideas on if the Commission were --

MR. OTT: Well, on that shift, you're shifting from on peak to off peak. Effectively, the analysis you're looking at looks a lot like storage in other words, and --

MS. SIMLER: Which goes back to some of Audrey's earlier comments about kind of how do we--right.

MR. OTT: I think you could look at generically, you know, if you had this kind of shift occur, if you had storage penetrate what types of outcomes or benefits would you see there. But I don't, I wouldn't even know how to approach, you know, an actual example of trying to figure out did a customer, you know, a customer doesn't come and tell me hey, I'm shifting my peak load to my off peak. That's just not something they're going to tell me.

Obviously I'll see their load going up and down, but with all the baseline calculations and these other things, I don't think I could track it. So I think I could certainly do an analysis or, you know, we collectively could do an analysis of what the benefits of on peak/off peak shift, which would help you with storage, Demand Response shift, etcetera.

But to try to do that based on actual action I think is--again, it goes back to the granularity with which you would do these things. It's just not attainable. The input date is not good enough to start with, and then --

MS. SIMLER: Do I need to talk this up as one of the things that we can't do easily, readily?

MR. OTT: I think so, no.

MS. ZIBELMAN: If I may, and that gets to the point, I think, of where we all started. If you compensated the LMP and people will make the investments in the storage and things, devices that allow them to do the load-shifting, because that's what they're trying to do.

They're not necessarily trying to reduce their energy consumption; they're trying to make their energy consumption more efficient, and they're using LMP to make investment decisions.

So by compensating them at the LMP, when they're able to reduce prices, that allows them to make the decisions with the outcomes there. If we all decide that's where we want to go, and we don't compensate folks for the investments they have to make to get us there, then it will never happen, and it's just run a fool's errand.

MR. HUNTER: Yes.

DR. SHANKER: Again, it seems that we are getting off course in terms of the discussion of the benefits of DR and the price. The benefits are undeniable. I have a client that I've worked with that round numbers, so I'll sort of keep them unidentified, 130 megawatts of load. It's a large industrial client.

They can shift, they have a preliminary or pre-processed good that they then finish. They can store that pre-processed good. So they have--part of their operations, maybe 100 megawatts, is creating an intermediate good in the manufacturing process that can go into storage, and 30 is finishing it.

So when prices are high enough, they back off their pre-processing and they, one of the projects I did with them, we sat down and figured out when they should build storage for this intermediate product.

They'll run a third shift and they'll take labor and they'll go over and they'll put that third shift on, when prices are high enough, and develop that intermediate good in the middle of the night. They'll buy electricity then, and then they'll only run during the day the 30 megawatts, and actually they'll run the 30 megawatts all the way through, okay.

Now they do that and will make that decision, whether it's LMP or whether it's LMP minus the retail rate, and in fact they've experienced both, and their behavior changes. So it's not like this goes away and suddenly nobody's thinking about storage or shifting. It's the question of how much should they be doing it. What's the right amount? What's the resource allocation?

It's not like if you don't give people LMP, they won't behave properly. They're going and doing it. They're doing it, and I think you're going to hear from a lot of people and what you heard in the comments was it's not a question of denying the process; it's the question of getting the quantity right.

If you're overcompensating people, understand where those subsidies go. Audrey's business is a lot tougher if it's LMP minus G than if it's LMP, because part of those subsidies will help her business. It's nothing against her business model, but that's the reality.

There will be more consumption of these types of resources if we pay LMP versus LMP minus G. The question I thought we were dealing with is is that good? Just to have more of it doesn't make it good. It's to have the right amount is what's good, and that's--somehow we're changing more and saying more is good just automatically, and it's just not true.

I mean we want to get the price right to get the level right. I mean why not pay two LMPs? I bet you you will get even more, and we can have a Net Benefits test that will show you paying two LMP will actually get you more Demand Response in the peak hours, and it will show a positive benefit.

MS. SIMLER: Right. My question was premised on the NOPR proposal of paying full LMP, and how to design a Net Benefits test, whether there's a Net Benefits test and how. So my presumption going into my question, I should have been clear, was LMP.

MR. GOLDENBERG: I have a question going back to Dr. Ethier's first comments. He outlined that there were two possible Net Benefits tests, value of energy consumption minus costs to producing energy or LMP reduction times consumption minus payment for DR.

Should the Commission adopt a Net Benefits test? I'm not sure whether everybody is really discussing both options, but I'd like to ask which one everybody would like to use, if the Commission went that way.

DR. ETHIER: Well clearly ISO New England supports the first one that you mentioned, which the area basically between the demand and the supply curves. It does not support the definition of Net Benefits that would basically be consumer cost reductions minus the cost of DR.

The only other thing I would add is I'm sure there are more than two possible net benefit tests, and those are just the two that seemed to be foremost in the discussion.

MR. QUINN: Bob, how would you do that? Would you do that on a kind of an after the fact basis by determining the number of hours or the price threshold, to then apply for the next X period of time and how would you define what the X, the next X period of time would be?

DR. ETHIER: Well, the nice thing about if you adopt a Net Benefits test that ISO advocates for, is that you don't need to do a test. If you get the payment rate right, there's no need to do a test because it just falls out.

MR. QUINN: By payment right, you mean LMP minus some retail rate?

DR. ETHIER: Yes.

MR. QUINN: What if we don't do that?

(Laughter.)

DR. ETHIER: Okay, then what's your question?

(Laughter.)

MR. GOLDENBERG: Oh well, I think the question is how do you do your test if you don't pay LMP minus G, but paid full LMP?

DR. ETHIER: Well, the test that I would advocate, you would--basically you would not pay in any hours the full LMP, because it wouldn't pass the test.

MS. ZIBELMAN: I think the difficulty we're having is LMP minus G means not paying for Demand Response. It means basically you get the savings and you don't get the service offering. If you're looking at, for a Net Benefits test, I think the attributes that I would suggest are the internal issues as to is it going to have the effect of reducing marginal price of LMP overall, or is it going to have the help of the dampening price increases.

So it's all the internal effect on the overall pool price. But I would also caution against setting it at the threshold too high. I mean the fact of the matter is that we're debating this is somewhat absurd. We have not required any other resource to demonstrate a benefit in order to enter this market.

We don't say well because you're call, we're only going to pay you when the market prices are five cents and above. So it's a little absurd. But if we're going to, it's because we're concerned that there may be hours in fact where reducing demand means that the numerator is high and the denominator so small that the unit cost per customer is actually going up.

Where that happens, quite frankly, is only at the flat part of the curve, when you get to base load. Anything above that, you have the effect of being able to reduce prices. So I would suggest that we are so far off with that. When we've done our calculations, we're about two percent penetration on Demand Response.

I do think that would be a high cost problem for this country, that we had so much activity on the load side that we saw a huge dampening of prices. But if we do, I think that you have to be careful not to set it so high that you're creating a result of unintended consequences, that you're not going to get the investments that you want.

MR. HUNTER: Don, go ahead.

MR. SIPE: Audrey's shortened my remarks considerably. But I want to be clear that, you know, the bid stack. Clearing the bid stack is a benefits test. You take resources in the order of their bids, and the idea is that that benefits consumers overall. I don't see why there needs to be a different test.

We provided a very small adjustment to the price that we think better reflects the marginal costs. As I said before though, over reasonable anticipated loads, with the penetrations that we've got for DR, the realistic need to have that govern dispatch is pretty small. But that doesn't mean there's no benefits test. What it means is there's a rational basis for the Commission to conclude that dispatching resources in mirror order provides benefits. That's a benefits test. Get them into the market; dispatch them.

Now I understand that you need factual analysis and ways of looking at it that allow you to conclude that. We think we have provided that. But it's fairly clear that when you've got two percent market penetration and you've got 70,000 megawatts of load, that if there is any difference between a DR bid and a generation bid that that's going to benefit everyone.

Even in the case where they're perfectly even, you're going to lower overall revenue requirements over time by dispatching them, to keep prices from going up sooner.

So I think there's a rational basis to conclude the simple bid stack methodology of dispatching resources in merit unit order is a benefits test, and if you want to refine it so you take care of the billing unit impacts, which are the only other impacts that really affect price--it's the missing money issue, there's an easy way to do that adjustment.

But I'm not sure that adjustment is going to make a difference in enough hours to justify departure from the simple marginal cost clearing that you've got. But that is a benefits test.

MR. HUNTER: And based on that follow-up, based on that, you know, climbing up the stack, whether it's a supply bid or a demand side bid, and paying the full LMP, Roy has argued that paying full LMP is a subsidy to Demand Response. Do you--based on what you said, do you agree with that premise?

MR. SIPE: No.

MR. HUNTER: Now you may argue whether you should or shouldn't subsidize Demand Response, but I --

MR. SIPE: No, no, because this goes back to the basic premise of what's the product you're selling. Number one, I just don't believe in Pareto optimality, which is what all the arguments are about, about efficient allocation of resources between all markets.

If you've got somebody that can do those calculations and actually do them based on economic theory, they've got a computer that's way bigger than anything we've got, you can't do those calculations realistically. You can just assume that everything's Pareto optimal, and then do graphs and charts that show the difference between the prices.

But that's not the real world we live in. Those externalities that are used to argue that there is a subsidy, are basically incalculable, which is why in one of my other answers I said we try to stay away from figuring out whether coal mining will be less if we do DR.

Because I have no realistic way of taking those externalities into account and figuring out--because I might have to take into account what's the wages for the coal miners that we may put out of business if we don't do that.

The permutations become endless. So no, it's not a subsidy. The appropriate function of the market is to provide just and reasonable rates. We've spent a lot of time defining that. Very simply, it's maximizing consumer surplus and not driving costs below --

And we've written a long paper on it, which I don't have time to review here. But it's a different market design objective. It is not the objective of this Commission, we don't think, to try to look at strip mining in North Carolina or somewhere else, and figure out in the wide scheme of all the markets, whether we're doing the best thing, because there's no reasonable way for you to figure that out. There is simply no construct that would allow you to make a reasoned determination.

MR. HUNTER: Thanks, Joel.

MR. NEWTON: I have to respectfully disagree with Don on a number of areas, in particular when we're looking at whether or not there is a subsidy. The fact that we're talking about also at the same time having some other amount that has to be redistributed, because nobody is paying for it. By itself, it's almost ipso facto that we're giving the money to somebody else.

You know, what this all is simply DRIPE, and there have been papers written by this is the Demand Response impact on price response. There have been papers written by Synapse on this already. They're published, they're out there for Energy DRIPE, and the effect that it will have.

In fact, I think the Massachusetts commission, in a staff report looking at the DRIPE effect, concluded that it absolutely was real, that energy--this was on energy efficiency, that it was a great product because the Massachusetts ratepayers financed it and it had a much greater effect on capacity prices overall.

We are talking about using DRIPE, this excess money that we're going to pay as a subsidy for this resource, to suppress overall energy prices in the market. That's the outcome we're talking about here. I'm very concerned that on a portfolio basis, a load portfolio basis, we're looking at somehow seeing how all of this can fit together, as opposed to individual demand resource entities looking at their own decisions on a stand-alone basis, as to whether or not in a given hour it makes sense to either shift their power to another period, turn off, store their power, do whatever they decide is in their best interest, as opposed to in society's best interest. Thanks.

MR. HUNTER: John.

MR. KEENE: Yes. I mean there's been a lot of discussion of DRIPE, and DRIPE is a term I think actually Massachusetts probably coined. But it relates--it's Demand

Response induced price effect, and it's a provision we use in assessing state-side, state-sponsored energy efficiency programs.

That's not what we're talking about here. We're talking about price response of demand. That's active Demand Response generally, not energy efficiency. So I just think, with all respect to Mr. Newton, he's comparing apples and oranges here.

But Mr. Hunter, I want to go back to your original question of what are the types of tests, and I essentially see three possible Net Benefits of tests that you can use. Something like Mr. Sipe is proposing; something, a static minimum offer price, which I believe is used in New York; or a dynamically adjusted minimum offer price, which is used in New England's day-ahead load response program, and which NECPUC supports.

There are probably numerous iterations in designs to a dynamically priced. Ours in New England is based on a gas price index and a heat rate for a marginal unit. Other regions may be able to pick something different, based on their resource mix and so forth. But those are essentially the three types I see, and I think NECPUC recommends our version for a couple of reasons.

Mr. Sipe's version does a very good job of assessing the Net Benefits. But for reasons Bob Ethier mentioned, related to, for instance, the impact on measurement and verification and baselines, we're concerned that there may be too much of an investment in DR, if we're looking purely at that.

So for the three, going back to the three recommendations we had for other considerations, mitigation of price formation concerns, mitigation of--if I can even remember them off the top of my head again--protecting the integrity of the measurement verification mechanisms, and minimizing potential adverse impacts on retail price responsive demand, we'd recommend going with something that restricts the dispatcher participation of DR to a lower number of ours, and I think Dr. Ethier mentioned it could be up to 7,000 hours.

Well, if we have DR participating in 7,000 hours a year, that's going to have a significant effect on the ability to roll out dynamic pricing and other price responsive demand mechanisms at the retail level. So we'd recommend restricting that to a shorter amount of hours.

But nonetheless, we have plenty of room for considerable growth in DR from the two percent that Audrey mentioned. That's simply inadequate. So we'd recommend something they could--we have a lot of room for growth, but something short of what would be under a natural Net Benefits test, as Dr. Sipe proposes. Thanks.

MR. QUINN: Can I ask a follow-up, and kind of for the whole panel. I don't think I've heard a lot of statements that say that the Commission should decide in the final rule that that Net Benefits test should be. I think most of you have said it should be a regional, you know, that we should--the Commission should allow the regions to decide what that test is.

Given that there are three tests you kind of laid out, I guess the question is does everyone agree that the Commission should in the final rules say that if there's a Net Benefits test, the regions should decide what that Net Benefits test is, and then the next question is how prescriptive does the Commission need to be, so that through the stakeholder process, you can actually get to an answer that you could come back with within the compliance period?

MS. ZIBELMAN: I think we all want to answer that one.

(Laughter.)

MR. PETERSON: I can give you a very short answer. Public Interest Organizations believe that the rule should say the goal or the principle should be a dynamic threshold that can get dealt with as the resources are clear to the day-ahead clearing process.

On an interim basis, you may need to default to some kind of a static threshold or a static threshold that gets adjusted periodically. That would be a second best option, and a firm, static threshold that never changes would be the worst option. We wouldn't want you to say that.

The reason it's important for the Commission to say something about this is if you leave it too vague, then we'll go back into the stakeholder processes, and all the arguments you're hearing here will take forever in the stakeholder process, because people will feel it's still an open question whether it's full LMP or maybe it's LMP minus something else. We can't call it G, but we'll call it something else that will make it come out that way.

So I think you need to give guidance on the principle. Do you need to prescribe that every region has to do the exact same Net Benefits test? No, I don't think so. You can leave some room for variability. But you want to set the parameters and the principles that every region would have to meet.

MR. HUNTER: I guess Audrey, go ahead. We'll go right down the line.

MS. ZIBELMAN: Yes. I think that there's an advantage of having a dynamic test, because you can review it, particularly if it's based on fuel type, and that's an advantage. The difficulty though, is that when people are constructing their bids and their schedules, that the test continues to change. It's difficult to make investment decisions, and so we have to weigh that.

I would recommend that the Commission, which is why we're suggesting that you just pick a point if you're making an administrative decision, at the point of this supply curve and say once we get down to that point, that becomes the threshold for Demand Response, and that could be either at the base load units. Someone's recommended the marginal unit.

But if you're going to go there, I'd say you pick that point on the supply curve. You have each RTO calculate what that might be, and you could do it seasonally. And then but be as prescriptive as you can, so that it's an issue of compliance as opposed to creation. Because I think if we go back to creation, we'll be here for another two years.

MR. HUNTER: Next. Go ahead, Don.

MR. SIPE: I have a tendency to believe with Audrey, that you should be as prescriptive as possible. Certainly, if based on the evidence you've got, you decide that the bid stack by itself is a sufficient test, that ought to be the rule for all RTOs, period.

I mean economics don't change. Penetration of DR is not that much bigger in one RTO than another RTO, and the economic principles we've been arguing about, about whether you pay LMP Minus G or LMP don't change from one RTO to the other.

That's really all we've been discussing here. So why we would have a different set of rules that you send us all back to our stakeholder processes to fight about, so we re-fight about whether we can find some tricky way to pay Minus G plus LMP instead of LMP Minus G or something else. I'm not sure why we would put people through that.

Second, I do think there's a pretty reasonable case to be made, given penetration and loads, that the bid stack is a benefits test that's sufficient. If that's not the case, then the threshold ought to be very low indeed, because the--basically the baseline considerations are not affected by where you set that threshold. I would disagree with Mr. Keene.

Baseline restrictions are an independent matter. You have to satisfy the contribution with respect to baseline, regardless of where you set the threshold. It doesn't matter. You could have no threshold, you could have a threshold anywhere you want. The independent consideration of whether or not your bid is accepted based on your baseline has to do with how your baseline is calculated, how many days you need to set a baseline.

None of that changes based on where that threshold is. Those are completely independent considerations. Given that we're going to have those baseline considerations, and in this I agree with Mr. Ethier, who said earlier, given that you're going to have those baseline considerations and the other constraints naturally occurring on DR, if you set a threshold just for the sake of doing it, it should even be lower than where I think Audrey's going.

I think it should pretty much allow what the Commission allowed in the first instance, which almost all reasonable hours where Demand Response could be allowed. In which case I get back, why are we setting this administrative threshold?

If there is any threshold at all, it ought to be based on empirical tests, the benefits. We think our mechanism would be the way to go, because it's not a threshold. It's just an application of marginal cost pricing.

I will say finally that we have the same feeling about the allocation methodology that we do about the baseline. Please don't send us back on allocation to every single RTO, where we can find clever ways of figuring out how we can allocate costs, so that we wind up paying LMP Minus G, or Minus G plus LMP, or something else.

There are simple ways of allocating costs that can be mandated, and the rules of economics are not different from one RTO to another on cost allocation either, for that matter. So with those points --

MR. HUNTER: Thanks, Robert.

MR. WEISHAAR: Thanks. You posed the question "if we adopt the Net Benefits," and I think that was pretty clear that we don't need to adopt the Net Benefits, given the self-regulating aspect of the market. As LMPs decrease, Demand Response will drop out, and it can just let the market decide.

However, if you're going to go down a path where you're adopting Net Benefits, I do see a distinction between day-ahead market and real time market. To the extent RTO is going to adopt a dynamic threshold and address the quote-unquote "missing money problem" in the day-ahead market, and I think it would make sense to do that.

I defer to the RTOs as to the practicality and cost of doing that. In the real-time market, where you have self-scheduling opportunities or dispatch opportunities, I think that becomes very impractical and extremely costly. It becomes even more difficult in the real-time market than it is in the day-ahead market. Some low level threshold for determining where you are on the very flat part of the curve may make some sense.

Procedurally, our fear is that, like some of the other panelists here, is that the Commission deliver all this back to the stakeholder process. Keep in mind that this rulemaking proceeding developed out of a PJM complaint proceeding, which in turn developed out of 18 months of a stakeholder process.

I would be extremely reluctant to suggest in any way that this issue be returned to stakeholder process, because the discussion there will evolve and branch out in a million different directions. I think the Commission should be very clear, provide general guidelines to the RTOs, and give the RTOs a reasonable deadline for filing a compliance filing.

To the extent stakeholders have concerns with that compliance filing, they will of course have the opportunity to file comments here.

MR. HUNTER: Thank you. Steve, do you have --

MR. SUNDERHAUF: Yes. I wanted to offer that we do believe a Net Benefits test should be established if we pay full LMP or some other form of subsidy to DR, and that one way to do so is to have general principles outlined by FERC and provided to the RTOs, and the RTOs then can work through the differences in their jurisdictions and come up with Net Benefits tests that are appropriate for their areas, that are transparent and easily calculated.

I would stress the importance of everyone in the market knowing ahead of time exactly how those net benefit tests are calculated, and the certainty of exactly when in time those results will be available, so people can make the right decisions regarding their resource offerings in the market.

MR. HUNTER: Next.

DR. SHANKER: I have to say I'm sort of torn. The comments you heard from Mr. Ethier were that if he defines the test the way he thinks is right, it won't--none of the things that involve subsidy, regardless of what Mr. Sipe thinks, will pass.

So we have a fundamental split here, is if you choose a path that has implicit in it a form of price discrimination, a form of subsidy, a form of what I see as monopsony power, I would prefer that you be explicit about it, so that you can address why you not ignore those concerns, but why you feel justified in going beyond those concerns to be proscriptive.

Because I think that the stakeholder processes will split just the way you would see. I think we all agree on that. And so also, I think if the Commission carries the burden of explaining why we should ignore those factors in making a decision, it will probably make things cleaner that we'll be fighting here rather than in ten different places.

And so in some sense of whatever it is, judicial economy, it may be best if you explicitly tell everybody what is the basis, why can you do that, and I don't think, from what you've heard today, you're going to change the mind of a number of people on either side.

So while I'd like to think that we'd go the right way, if you are going to go a way that I personally consider wrong, I'd rather see it explicit, well thought-out, explained and then there be a basis for us to possibly come to the Commission or go elsewheres to see if we can remedy it if we disagree. Or if not, you know, it goes forward.

But there's no point to do this in--well, it would be seven markets or whatever, at least the three, or the three eastern markets.

MR. HUNTER: Mr. Rigberg, you've been up there for a while.

MR. RIGBERG: Yes, thank you. Yes, I too would strongly urge the Commission to be prescriptive, as most people have said, and also to be concerned about the creation of seams, you know, between the markets. So I think that should be, you know, in your mind as you go forward. Thanks.

MR. HUNTER: John.

MR. KEENE: I just wanted to go back, as one of the few who recommended you do send this back to stakeholders. I meant that in a very, you know, I won't repeat everything else, all our other recommendations.

But I do want to point out and clarify that we think you need to be sufficiently prescriptive, to make sure some of the debate you heard today and in the initial comments related to compensation level, that you don't leave the door open for the benefits debate or the cost allocation debate, to reopen the compensation debate.

You need to, as Mr. Shanker said, you know, really decide the compensation level decision, and clearly justify your reasons for making that decision, and let that be closed.

MR. HUNTER: Okay, thanks. Bob.

DR. ETHIER: I just wanted to make the observation that at least in New England, this--getting this decision resolved is an impediment to all the other stuff we want to do with price response to demand, and DR generally in our market.

So until we get through this, we're not going to make much progress on ancillary services, on comparability in the capacity market, integrating DR better into the dispatch.

We need to get this solved as quickly as we can get it resolved, so that we can move forward and make some progress on all the other issues that I know the Commission really wants us to make progress on and that we want to make progress on. So I just want to throw that out there, that this is really--until we get past this, we're not going to be able to get there.

And if you, you know, the implication of that is if you send something back that leaves a lot of room for debate, it's going to be a while on all those other things. Just an observation.

MR. HUNTER: Thank you for that astute observation. Go ahead. Go ahead, Joel.

MR. NEWTON: Very briefly. I really agree with what all you had to say, as well as the real concern that we need to be prescriptive in whatever the Commission is doing. The seams issue is a real one in the eastern RTOs, and if we do end up with very differently defined products, the seams will become a problem very, very quickly in the energy markets.

The last point I just wanted to make briefly was that we have three other RTOs that are not represented at this table, CAL ISO, MISO and SPP. None of them have active capacity markets. We are talking about a product that maybe will be defined differently there.

The Commission probably should be doing some thinking into how these various products that we're creating should be differentiated in the different markets, where they are being compensated in very differing ways.

MR. HUNTER: All right. So it seems like a natural break. It's noon.

(Laughter.)

MR. HUNTER: Do the Commissioners have anything they'd like to add or ask?

(No response.)

MR. HUNTER: Okay.

MR. GOLDENBERG: Just one thing. We're going to all the written comments that we've received we're going to put on the record. If you have anything that you want to add to the record, you should file it with the Secretary. I think Dr. Ethier mentioned there was some report that he might want to put on the record. He should file it with the Secretary. Thank you.

MR. HUNTER: Okay, thanks. We're reconvene at one o'clock. We're on schedule.

(Whereupon, at 12:00 p.m., a luncheon recess was taken, to reconvene at 1:00 p.m., this same day.)

AFTERNOON SESSION

(1:05 p.m.)

MR. HUNTER: Okay, so this afternoon's panel is on Cost Allocation. The same format as this morning. We will have brief, five minute, remarks from the ten panelists, this time, and then we will open it up for discussion.

First let me introduce the panel. We've got Commissioner Paul Centolella from the PUC of Ohio. Dr. William Hogan, Professor at Harvard University. Sonny Popowsky, Consumer Advocate from the State of Pennsylvania. Michael Robinson, Senior Manager, Market Development, from Midwest ISO. Carl Silsbee, here from California, Manager of Resource Policy for SoCal Edison. Tim Brennan, Director of Wholesale Markets for National Grid. Kenneth Schisler, Senior Director of Regulatory Affairs for EnterNOC. Angela Beehler, Senior Director of Energy Regulation/Legislation for Wal-Mart. Megan Wisersky from Madison Gas & Electric, representing the Midwest TDUs. And Jay Brew, counsel for the Steel Manufacturers Association. Thank you all for coming.

Anything from the Commissioners before we started?

(No response.)

MR. HUNTER: Okay. With that, we will start off with Commissioner Centolella.

OHIO COMMISSIONER CENTOLELLA: Thank you for this opportunity to comment on the Commission's proposal for Demand Response compensation and related cost allocation issues.

The ability of Demand to respond to energy prices is an essential characteristic of an efficient, competitive market. Demand Response provides significant economic and reliability benefits. It can avoid the need to rely on more expensive resources, mitigate market power, and improve power system reliability.

The Commission proposed requiring RTOs to pay economic Demand Response program participants in all hours the energy market price, or full LMP. Where the Demand Response program participant is not reselling already-purchased energy, paying LMP instead of LMP less the avoided generation portion of their retail rate, will compensate the participant by an amount that substantially exceeds the marginal cost of energy and the price being paid to generators.

The extent to which each participant's total compensation exceeds the energy market price depends on their retail rate, and therefore will vary widely in ways that are not directly related to any Demand Response policy objectives.

The Ohio Commission has not opposed RTO Demand Response programs to provide it additional limited temporary incentives designed to support the initial development of Demand Response. However, RTO programs should seek to provide an efficient level of total compensation to program participants. Any additional incentives should be reasonably required to address market imperfections or achieve other carefully defined policy objectives. Requiring all RTOs to pay full LMP does not meet this test.

The Net Benefits test reflects a recognition that paying full LMP may over-compensate Demand Response and increase cost to consumers. It is a complicated approach. The formula approach we heard this morning, based upon maximizing consumer welfare, would fundamentally change the objective function in RTO dispatch algorithms.

Moreover, while Demand Reductions could lower LMP if the slope of the supply curve is sufficiently steep, this will not uniformly occur above any certain price point. And any reduction in energy market prices may simply increase capacity market prices, making the overall calculation of Net Benefits complex.

The Ohio Commission is concerned that FERC's exclusive focus in this docket on the payment of LMP for Demand Response resources could have the unintended consequence of retarding the development of price-responsive

Demand.

While significant, RTO Demand Response Programs reach a small percentage of consumers. Advanced metering and dynamic retail rates would give many more consumers control over their electric costs. Electricity markets would increasingly resemble competitive markets in other sectors of the economy where consumers simply see and respond to prices.

The factual premise put forth by proponents of the full LMP approach is one that is rapidly changing. Millions of advanced meters have been and are being installed. Initial dynamic pricing experiments have shown promising results, and utilities in collaboration with the U.S. Department of Energy and State Commissions are undertaking carefully structured experiments to identify the best combinations of dynamic retail rates, information, and enabling technology for residential and small consumer customers.

The FERC's national assessment of Demand Response potential examines the potential for dynamic retail pricing and found that the largest gains in Demand Response impacts can be made through pricing programs.

The cost of reductions in peak demand to residential consumers also appears to be substantially lower than the costs of curtailments to industrial energy users and commercial consumers who provide the majority of Demand Response in RTO programs.

Moreover, when implemented in a SmartGrid, Demand Response can provide a broader range of economic and distribution system benefits not available from RTO Demand Response programs.

This Commission has recognized that appropriate coordination of--the lack of appropriate coordination of wholesale and retail markets can operate as a barrier to Demand Response participation. However, the Commission has not yet, one, removed the resource adequacy requirements that force price-responsive loads to carry capacity for demand that would not be present at higher prices; two, ensured nondiscriminatory treatment of price-responsive demand; or three, completed the implementation of scarcity pricing under Order 719.

In addition to diverting attention from these key issues, the payment of full LMP could retard the development of price-responsive demand in two ways:

First, the purchase of Demand Response resources at full LMP effectively discriminates in favor of RTO program participants over consumers responding to retail prices, and will displace price-responsive demand that could have curtailed for less than the total incentive received by RTO program participants.

And second, the additional incentives for Demand Response resources will increase RTO costs that flow back to utilities and consumers, leaving fewer resources to make the necessary investments in metering and enabling technologies.

The costs of DR programs should be allocated to those who benefit, with allocations dependent upon the objectives and nature of the incentives provided.

Where an RTO uses limited incentives to support the development of Demand Response in a zone or region, the cost of these incentives may be allocated across the zone or region to reflect the shared market benefit.

Despite the previous difficulties mentioned, where there may be some legitimate basis for tracking Net Benefits, such benefits could also be used as a basis for cost allocation. If the Commission directs RTOs to pay full LMP, it needs to clearly state its objective and should adopt cost allocations that minimize distortion in rates. There may not be a single standard approach for all RTOs in this case.

In conclusion, to focus narrowly on wholesale prices for Demand Response while ignoring the retail price signals seen by actual consumers will ensure an inefficient outcome. It is an outcome that states may not be in a position to correct, as we do not regulate the rates of competitive LSEs.

Efficient markets require coordination between FERC and State Commissions. Such coordination can support the development of the next, more efficient generation of Demand Response based on a broad implementation of price-responsive demand.

Thank you.

MR. HUNTER: Thanks, Commissioner. Next up we've got Dr. Hogan.

PROFESSOR HOGAN: Thank you very much for having me here today. I've prepared written comments, which I have provided, so I am not going to repeat everything, but I wanted to emphasize a few questions, several questions, that are in those comments.

Why are we here?

Why is this subject so confusing?

Why are retail rates relevant?

How can we match ends and means?

Do we need a Net Benefits test?

How should we allocate costs?

And where should we go from here?

Why are we here? Well, I think that's pretty well understood, and I've described it further, but it's to see how Demand Response fits into the larger market design. It's an important test, and we want to make sure it is compatible with the rest of the system. And I submit that the current proposal is not compatible with the rest of the system, so it is important to try to get this straight.

Why is this subject to confusing? This is such an important point that I am going to read, literally, what I submitted: In his NOPR reply comments, Alfred Kahn refers to, quote, "to the proposition, in principle indisputable, that demand response is in all essential respects economically equivalent to supply response; and that economic efficiency requires, as the NOPR recognizes, that it should be rewarded with the same LMP that clears the market. Since DR is actually and not merely metaphorically equivalent to supply response, economic efficiency requires that it be regarded and rewarded equivalently as a resource proffered to system operators and be treated equivalently to generation in competitive power markets." End quote. This is an important premise, critical to the Commission's proposal.

Were it true, the present proceeding would not be necessary. But it is not true. The megawatt of Demand Response is a powerful metaphor, but a megawatt negawatt is not equivalent to a megawatt. The two have features in common, but they are not the same physically or economically. Useful application of the "Negawatt" Idea requires care in the analysis.

Amory Lovins, originator of the Negawatt Idea, has been quoted as saying that he takes economics, quote, "seriously, not literally," end quote. This is good advice, and it would apply as well to the design of compensation rules for providing Demand Response through providing Negawatts.

Taking Negawatts and Demand Response seriously is good policy. Building a Demand Response policy on a literal application of the megawatt metaphor produces contradictions and conundrums.

The fundamental contradictions and conundrums center on the difference between reselling something that you have purchased, and selling something that you would have purchased without actually purchasing it. If the something is a kilowatt hour of electricity, the two conditions are physically identical in providing Negawatts, but they are fundamentally different in economic terms.

The former kind of Demand Response is easy to accommodate in prices the Commission has proposed, and the latter requires more care in the design of the compensation mechanism.

Why are retail rates relevant? There are many who have argued that we shouldn't look at the retail rates, and in effect we should be drawing a veil of ignorance over the retail market and just look at the wholesale market and we don't have to worry about the rest of it, let's just have efficient pricing in the wholesale market.

But I think the implication of that argument is exactly the opposite of what has been suggested. Because if we drew that veil of ignorance over the retail tariff and we just looked at the wholesale market, we would say well what's the right thing to do?

Well, real-time pricing is the right thing to do. And charging the LMP for the megawatt hours they consume, and you're done. You don't need an additional Demand Response program, and it would be inappropriate to do so. But the problem is, we know that in the retail rate side the demand that's being represented is not an accurate representation of the demand. It's not the way the real cost incurred are incurred in the system. And so the whole motivation for having special Demand Response programs is precisely because of the retail rate structure.

And pretending that you can ignore that is just backwards thinking. And if you did ignore it, you would get the opposite answer that everybody seems to suggest. So I am in favor of efficient Demand Response programs. I'm not in favor of doing nothing. But the notion that you can ignore the retail rate I think is a perverse twist in the logic and it doesn't make any sense. We have to look through to that.

How can we match ends and means? Well, I'm going to not summarize that here because I don't have enough time, but just to say that this is where I discuss, among other things, the point about reducing the price to consumers is not an appropriate benefit for FERC to be considering.

From the perspective of generators, this is a cost. From the perspective of loads, it is a benefit. But from the perspective of economic efficiency and welfare maximization, the aggregate effect is a wash and there is no net benefit.

To the extent that the Commission's proposal depends on the benefits of price reduction, the policy arguments amounts to no less than an application of regulatory authority to enforce a buyers' cartel. The Commission has been vigilant and aggressive in preventing buyers and sellers from engaging in market manipulation to influence prices, and it would be fundamentally inconsistent for the Commission to design Demand Response compensation policies in order to coordinate and enforce such price manipulation.

So I think that an efficient set of Demand Response policies would be appropriate, but that would not count as benefits by changes in the prices to the final consumers.

There are many other points that are in the written testimony. There is a simple summary of the basic line of the argument, which is, I agree with him [indicating Commissioner Centolella]--

(Laughter.)

PROFESSOR HOGAN: So I am going to save myself some time, except to emphasize one point, which is: I agree with him, but to say how important it is. It says: The Commission's work under Order 719 on scarcity pricing is important and should be a high priority in conjunction with the promotion of the SmartGrid.

And where should we go from here? We should go to that meeting.

Thank you.

MR. HUNTER: Thank you. All right, next we have Sonny Popowsky from the Pennsylvania Consumer Advocates Office.

MR. POPOWSKY: Thank you. My name is Sonny Popowsky. I've served as the Consumer Advocate of Pennsylvania since 1990, and I've worked at the Office of Consumer Advocate since 1979.

I want to thank you for inviting me to participate in this technical conference on behalf of Pennsylvania Electricity Consumers.

My office has joined with several other state consumer advocate offices in comments filed in May generally in support of the Commission's original proposal in this docket to require the Demand Response that is dispatched in regional energy markets be compensated at full market clearing prices.

Now before addressing my general support for the Commission proposal and the allocation of cost resulting from this proposal, which is the subject of this panel, I want to provide the Commission with some background about why this issue is of such great importance in Pennsylvania.

As many of you no doubt recall, Pennsylvania was one of the first states to restructure our electric industry and open the generation portion of the industry to competition.

At the same time, though, Pennsylvania implemented a lengthy transition process from regulation to competition first of all to protect utilities who wanted to recover stranded costs to protect against the expected loss in value of their generation plants, and secondly to protect consumers through long-term retail rate caps so that our consumers would not have to pay both stranded costs and higher market generation prices.

Now those caps and those stranded cost recoveries end at the end of 2010. So starting on January 1, 2011, the people in Pennsylvania will be paying rates that are totally based--totally based--on the prices that we pay, or that our load-serving entities pay primarily in the PJM market.

Now as you know, one of the key features of PJM is the single market clearing prices, where all units that are dispatched in a given hour are paid the price bid by the highest priced generating unit. And while only a fraction of the generation that is sold to Pennsylvania consumers is purchased each day in the PJM Spot Market, in the spot market, there's no question that the price of power sold in PJM, whether through Spot purchases, Block Power purchases, Full Requirements' Contracts, or even Long-Term Contracts, at least I believe are heavily influenced by the actual and anticipated energy prices in the PJM market.

Now while prices in PJM, energy prices are currently quite low due to low fossil fuel prices and the severe economic slowdown, we have seen the catastrophic results that occurred in States such as Maryland when rate caps came off at a time when PJM prices were extremely high.

Now in my view the current FERC NOPR represents an important and potential valuable effort to prevent excessive energy prices in wholesale markets such as PJM. To the extent that Demand Response programs can in fact displace higher cost generating units in the PJM dispatch, then the impact on the cost to consumers who are purchasing power through the PJM energy markets can be profound.

That is because, what I call the multiplier effect, which you are all familiar with, which is that each time that a higher priced generating unit is dispatched in PJM, that higher price is paid to all the thousands of megawatts of generating units that are online at that time.

When a Demand Response program is implemented, instead of bringing on a higher cost generating unit, the effect is exactly the opposite. That is, the avoided increment to the market clearing price is multiplied across every generating unit that's operating in that hour, and the savings flow to consumers.

As long as the incremental cost of paying for the Demand Response compensation is less than the savings produced by any reduction in generation costs resulting from the lower market clearing price, in my opinion all customers who are purchasing power in that market at that time will benefit.

Now that brings me to the direct point at issue here, which is Cost Allocation. In our comments filed in May we didn't address the question of Cost Allocation, but I think that that issue was very clearly and correctly in my mind addressed by NECPUC, the New England Council--the New England Conference of Public Utility Commissioners. And let me just read from their comments that were filed:

NECPUC recommends allocating the costs of procuring Demand Response resources to all consumers purchasing from the relevant energy market in the hour when the Demand Response resource is committed or dispatched. The rationale for this approach is that it allocates the cost of Demand Response resource procurement on the basis of Cost Causation--i.e., Demand Response resource costs are allocated directly to those energy market consumers who benefit from the Demand Response service provided.

I agree with that statement in the NECPUC comments; that this is essentially a matter of establishing Cost Causation and assigning the costs to those who benefit. Again, as long as the incremental cost of spreading the Demand Response compensation across all affected load is less than the savings that result when the Demand Response resources displace higher cost generation, then all affected load will benefit. And as such, it is appropriate in my view that all consumers who receive that benefit, whether that is on a zonal or multi-zonal or RTO-wide basis, should share in those costs.

Thank you again for inviting me to participate, and I look forward to your questions and the rest of this discussion.

MR. HUNTER: You're welcome. Thank you. All right, thanks. Next we have Michael Robinson from Midwest ISO.

MR. ROBINSON: Thank you. Thank you, Commission staff, and Commissioners, for this opportunity to speak on this topic.

At Midwest ISO we certainly are involved and doing our best to actively engage Demand Response in our markets. We have over 10,000 megawatts of Demand Response in our markets. And to my understanding, we are the only RTO in the States that has a true Demand Response resource providing regulation service. Not a behind-the-meter generator, but Demand Response.

We have an active stakeholder process that is engaged in removing barriers to participation. We come under the philosophy of we're conducting these markets for our various products and services. How do we establish a level playing field? How do we make these resources comparable--provide comparable treatment across generation and Demand resources.

So you asked a few questions here today. One is: Is the Cost Allocation a function of the level of compensation? What's the appropriate Cost Allocation method? And then finally, should we use a net--what's the role of a Net Benefits test in the role of Cost Allocation?

Let me address the last one first. A couple of speakers this morning already fleshed this out, but clearly if you get the markets right in terms of competitive markets and efficient pricing, you don't need a Net Benefits test. Okay? So if the counterfactual to that is when would you need a Net Benefits test, would be--or the contrapositive would be, you would need a Net Benefits test when the markets don't work.

Now a couple of different reasons where markets wouldn't work. Dr. Hogan talks about one of them in his paper, when you have inefficient pricing. To mitigate the harm to market participants, you may want to have a situation where you do have particular Cost Allocation.

The other one where markets don't work is where I can make the case that for some reason there is a positive externality--there's market failure, and there's a positive externality associated with this particular resource. In that particular case, then that may be appropriate for Cost Allocation.

Having said that, though, does the Cost Allocation depend upon the level of compensation? It truly does. If there is inefficient pricing, or positive externalities, that will suggest a particular Cost Allocation scheme.

If you get the prices right, then I think the Cost Allocation flows directly. What we proposed, and this was involved significantly through the stakeholder process was, we would--and Andy Ott talked about this this morning, where from the wholesale markets administrator's point of view, the value of the load drop is truly LMP.

So pay the DR, provide LMP, but appropriately charge the load-serving entity LMP. Okay, and then recognizing, look behind the curtain, recognizing that there's some avoided retail revenues that have to be accounted for.

I can think of at least five or six different reasons why the Cost Allocation should go to the appropriate LSE. One is, examine the counterfactual. Essentially if the load didn't drop off, the load-serving entity would have to serve that load would be paying LMP.

The second one is, the argument then is, well, you're going to have to somehow reconstitute load to settle it out appropriately, to solve the "missing money" problem. So there's this funny concept called "reconstitution of load." Whereas in the world where there's just generator and load, you'd sort of directly meter what they inject and what they withdraw.

Yes, it's true it's a little bit of an odd concept, reconstitution, but it's no different from calculating a CBO, which may not be reconstituted but it's certainly constituted. So in that sense it's sort of comparable to what we do with trying to measure the load drop from a Demand Response asset.

The third reason I guess in the interest of time I won't talk about too much. I think Dr. Shanker talked about it this morning, the sense of if you have significant baseload generation that comes in, that's going to depress LMPs and provide net benefits to the market.

And so the whole issue of do we want to have uplifts that distort prices, we're trying to avoid that.

The next reason is, if you think about how retail rates are structured under a fixed tariff, the design is hopefully to set up a rate so that on average costs are recovered. The result of that, though is that during the high peak hours the retail utility is actually losing money and recovers additional monies in the off-peak hours and the low-cost hours.

So if we don't charge the LSE, then it's possible that the LSE will incur windfall profits, and so that has to be addressed.

Number five is the call-option argument. That's been well discussed this morning.

Then the last one is, no one has really talked about this one, but typically load-serving entities procure most of their obligation in the Day-Ahead. So if you don't charge the LSE for this particular load drop in terms of reconstituting load, then essentially you're paying for that load drop twice. You're paying the third-party provider, the DR provider, and when the LSE sells it back in real-time he's getting compensated as well. So you're paying for the same megawatts twice. And so that's the last rationale for providing--charging the LSE.

We recognize that if you look behind the curtain that there are avoided retail revenues that the LSE in this particular regime is not indifferent. And so as a service to the LSEs and to the retail--the relevant electric retail regulatory authorities, we offered to back out from the LMP the marginal foregone retail rates that the end-use consumers were avoiding.

We provide that as a service. If this Commission decides that the appropriate compensation is LMP, then I'm sure that the relevant electric retail regulatory authority will make that case and flow those credits back to the LSE from the third-party provider.

Thank you for giving me this opportunity to speak.

MR. HUNTER: Thank you. Next up we've got Carl Silsbee from SoCal Edison.

MR. SILSBEE: Thank you. Good afternoon Commissioners. Thank you for the opportunity to participate here today.

My company, Southern California Edison, has actively pursued a wide variety of retail Demand Response programs for over 30 years. Today we have about 1700 megawatts of proven capacity from our Demand Response programs, which represents about 7 percent of our service area off-peak demand.

Our largest single program is an air conditioning cycling program for residential and small business consumers. There's over 300,000 participants on that program, and it supplies about half our total Demand Response capacity.

We are in the process of transitioning that program from a purely reliability-based program to a program that will include a price responsive trigger and, as such, will bid into wholesale markets managed by the California Independent System Operator.

The certainty of our Demand Response program capacity is assured through a combination of performance incentives, performance penalties, and hardware control, depending on the nature of the specific program.

The capacity value assigned to these programs by the California Public Utilities Commission is periodically adjusted to reflect actual historic experience. Forward capacity obligations are managed by the California Public Utilities Commission in California, not through the California Independent System Operator.

We rely on our Demand Response programs both to maintain system reliability, and to give participating customers better options to manage their electricity consumption and their retail bills.

Over the last several years, the California ISO has managed a stakeholder initiative to create a wholesale market process called Proxy Demand Resource, or PDR. This is a program, not a specific product, and we see it as the vehicle that we will use to integrate retail price trigger Demand Response programs into wholesale market operations at the California ISO. PDR bids will be awarded and settled in a manner that is comparable to supply side resources.

Our major interest in this proceeding has been to assure that the Commission's final rule will support the progress that we have made in developing effective retail demand response programs, and integrating them into wholesale markets.

We are pleased that the Commission approved the California ISO's PDR tariff filing last July. We think that is an important step forward to effective integration of retail Demand Response into wholesale markets.

We support the proposed rule's conclusion that Demand Response compensation in wholesale markets should be at the LMP. This is consistent with how PDR is designed. While we agree with those who recommend an adjustment for retail bill savings--the so-called "minus G" adjustment--we believe that this is properly the jurisdiction of state regulatory agencies, and that FERC should neither require nor enjoin the use of a Minus G adjustment at retail.

Let me turn to the issue of Cost Allocation and talk a little bit about how the PDR handles Cost Allocation. It appears from the discussion in the supplemental NOPR that some parties are viewing the payments made to Demand Response participants as an Uplift, or an Out-of-Market Cost that needs to be assigned to some class of market participants.

That isn't the way things function in the California PDR. Under PDR, consumer reductions electricity consumption are treated as a supply element and paid at the LMP, just like a supply resource.

As a result, these load reductions do not create Uplift or Out-of-Market Cost that needs to be allocated. Instead, the amount of consumer load reduction is added to the recorded usage of the participating consumer's load-serving entity.

This balances the books. It means that the Minus load for the Demand Response provider is offset by Plus load for the LSE. It also means that the Minus LMP that goes to the Demand Response provider is balanced by a Plus LMP which is recovered from the market, from all demand, based on how demand brings energy into that market.

Thus, Demand Response resources are paid for by load-serving entities who choose to pay the full LMP in order to obtain energy for their consumers. The key point is that this occurs through the normal settlement mechanisms in the wholesale market, and treats Demand Response in a manner that is analogous to supply resources without any Uplift or Out-of-Market Costs to be allocated.

So thank you for your attention. I look forward to any questions you may have at the conclusion of the panel.

MR. HUNTER: All right, thanks, Carl. Next up we've got Tim Brennan from National Grid.

MR. BRENNAN: Thank you. National Grid would like to thank the Commission for establishing and organizing this technical conference to allow further stakeholder input and discussions of these important questions posed in the Supplemental NOPR regarding the Demand Response compensation in organized wholesale markets.

National Grid appreciates the opportunity provided to present its views today as part of this Panel Two established to consider the requirements for ensuring the proper allocation of costs associated with Demand Response compensation in the markets.

While this panel is not addressing the compensation itself, or the requirements of any Net Benefits test, if used, to determine when compensation might be appropriate, the issue that was dealt with by Panel One this morning, I would like to briefly remind the Commission of National Grid's position on the compensation proposed in the NOPR.

As stated in our comments filed May 13th for Demand Response Resources Dispatched in Wholesale Energy Markets, National Grid supports full LMP compensation in certain limited hours when Net Benefits to the market outweigh the costs, and for all other hours supports compensation at the LMP-minus-generation costs they avoid in the retail rates by foregoing consumption, otherwise known as LMP-minus-G.

Well-respected economists have submitted opposing views on the appropriate compensation level in this proceeding. Some have argued that no compensation greater than LMP-minus-G can be justified in any hour; while others have argued that principles of economic efficiency require allowing full LMP compensation in all hours.

Given these well-presented but opposing views, it appears quite reasonable for the Commission to consider the use of a Net Benefits test to determine in which hours full LMP compensation might appear most justified.

For example, in hours when the total energy market LMP savings from a demand reduction more than offset the costs of such compensation to the associated resource.

Of course with any compensation of resources dispatched in the wholesale markets, there is an associated cost which must be allocated. The Commission has asked this panel to focus on the issue of what, if any, requirements should apply to how the costs of Demand Response are allocated.

For National Grid, the single most fundamental requirement to apply is the requirement that the costs at issue in this proceeding--that is, the compensation costs paid to demand resources actively competing with generating resources in the wholesale energy markets--be allocated entirely to the entities responsible for the load-serving obligations in the wholesale energy markets.

These costs should not be allocated as transmission charges to transmission customers. Costs associated with Demand Response programs have at times in the past been allocated as transmission charges rather than as market charges.

However, such programs and associated costs were considered essentially unrelated to the competitive operation of the wholesale markets; but instead were supported as programs enhancing the reliability of the network during periods of peak demand.

Clearly the Demand Response programs and associated costs at issue in this NOPR are very different. As the Commission stated in the NOPR, quote, "Our focus here is on consumers providing, through bids, Demand Response that acts as a resource in organized wholesale markets." End quote. And that this, quote, "helps to improve the functioning and competitiveness of such markets in several ways," end quote, including through the lowering of energy market clearing prices and the mitigation of generator market power.

Moreover, the Commission clearly stated its belief that the proposed comparable treatment of Demand Resources and Generation Resources, quote, "will improve the competitiveness of the organized wholesale energy markets, and in turn help to ensure that energy prices in those markets are Just and Reasonable." End quote.

It is National Grid's belief that the Commission will ensure the associated Cost Allocation is Just and Reasonable if it requires the cost to be allocated only to the entities that hold the wholesale energy market obligations for the load in the control area.

Once that fundamental requirement is applied, National Grid believes the Commission need not apply any additional requirements at this time. The RTOs, ISOs, and stakeholders in each region should be allowed to take account of their particular energy market designs and settlement rules, and then consider and propose how best to achieve the goals of this NOPR while properly allocating the compensation costs among their energy market participants.

For example, the Consumer Demand Response Initiative has presented an interesting proposal consisting of Day-Ahead Market Pricing algorithms, and Settlement algorithms, which may be worthy of further consideration.

Also, regions and stakeholders will need to consider many allocation choices such as using Day-Ahead obligations versus Real-Time obligations, using Hourly periods versus Daily, targeting All Load-Serving Entities versus the Load-Serving Entities realizing the load reductions, et cetera.

With the simple but very important guidance from the Commission requiring that these energy market compensation costs be allocated only to entities responsible for the wholesale energy market obligations, National Grid is confident the regions will be able to work through the remaining details and propose a complete set of rules for the allocation of these Demand Response costs.

Again, on behalf of National Grid, I thank the Commission for this opportunity and look forward to participating in the panel discussion to follow.

MR. HUNTER: All right, thanks. Next up we've got Kenneth Schisler from EnerNOC.

MR. SCHISLER: Thank you, and thank you to the Commission for this opportunity to testify today at this technical conference surrounding Cost Allocation of Demand Response Compensation as proposed in the Compensation NOPR.

EnerNOC appreciates FERC's desire for a complete record upon which to base its final rule in RM10-17, and welcomes this opportunity to submit additional comments on Cost Allocation.

My opening comments are focused on two specific points. First, we do not believe that the final rule needs to codify specific determinations on Cost Allocation. While we recognize the importance of the issue, we believe Cost Allocation issues can and should be considered in the stakeholder processes at each RTO and ISO following the issuance of a final rule--that each RTO and ISO should have the opportunity to address Cost Allocation in the compliance filing process that is appropriate under the market design for each RTO and ISO.

Our second point: Though it is not necessary to address Cost Allocation in the final rule itself, we respectfully suggest, and strongly so, that FERC do offer guidance in the Order accompanying its final rule on Cost Allocation.

EnerNOC agrees with numerous commenters in this rulemaking that suggest that Cost Allocation principles should be broad-based and premised upon a beneficiaries' pay approach. Specifically, we submit that Cost Allocation must be broader than the load-serving entity of record for the Demand Responding customer, as such an approach would put the load-serving entity of record in a position of opposing Demand Response efforts and create and cause to persist a barrier to Demand Response.

To the first point: EnerNOC recognizes that Cost Allocation issues and Demand Response compensation issues are linked. That is to say that implementing a full LMP pricing regime for Demand Response will necessarily cause the RTOs and ISOs to consider whether Cost Allocations are workable, or whether they will require changes.

However, while there is a linkage, it does not follow therefore that FERC needs to include both issues as part of a final rule on Demand Response compensation. Nor does it follow that Cost Allocation necessarily needs to be applied in the same way everywhere.

Recognizing the differences in market designs amongst the RTOs and ISOs, it is entirely reasonable for FERC to adopt a final rule addressed to Demand Response compensation only as is currently proposed.

Instead of expanding this NOPR in order to codify Cost Allocation principles in federal regulation, FERC should instead offer whatever policy guidance on Cost Allocation it may deem necessary in the Order and direct the RTOs to propose any necessary changes in the compliance filings.

This approach would afford RTOs and ISOs the opportunity to consider the means to implement the final rule consistent with FERC policy in a manner that is conducive to the particular market design.

To the second point: As I said, while we do not believe FERC needs to codify a specific approach to Cost Allocation, we do believe it would be incredibly helpful for FERC to offer general policy guidance to stakeholders at the RTOs and ISOs so that it will then, in the compliance filing process, be considering Cost Allocation policies, whether those policies need revisions.

To this end, we suggest the FERC should offer guidance that any Cost Allocation method adopted should not work in conflict with a final rule, or otherwise erect new barriers to Demand Response.

The policy guidance to be offered in essence--without policy guidance the Cost Allocation methodology adopted could completely undermine or reverse or create a Minus G scenario. So for that reason, we are suggesting that the Order accompanying the final rule should make sure that any Cost Allocation method is consistent with the policy proposal in the final rule.

As an example, it has been suggested that among the options for allocating cost would charge the LSE of record for part or all of the costs of Demand Response. We've heard that testimony here today.

We believe that these approaches would work at cross purposes with the final rule, and should be avoided. As was described by PJM in the comments in this docket in which they listed various options, allocating part or all of the costs of Demand Response to the LSE of record would leave the LSE of record in a position to absorb a disproportionate share of the cost of Demand Response, and may even create situations in which the LSE is financially worse off.

Such a model, we submit, would not be sustainable and would, as PJM acknowledges, perpetuate and even worsen problems that persist today under this Cost Allocation method. And those problems of course are outlined in PJM's testimony, but they deal with a frequency of settlement disputes and persistence of LSEs essentially resistant to Demand Response settlements.

With that, in the interests of time, I will conclude my comments.

MR. HUNTER: Thank you. Next up we've got Angela Beehler from Wal-Mart.

MS. BEEHLER: Thank you for the opportunity to provide comments addressing Cost Allocation of Demand Response. Wal-Mart is an international retailer that has the privilege of serving customers in over 4200 U.S. and 4300 international locations.

Experience with curtailment services has enabled Wal-Mart to be a leading advocate for energy policy on demand response. When consumers utilize the proper equipment, they can make a substantial difference, spreading the benefits to all ratepayers through participation in the wholesale DR markets.

Wal-Mart is a DR participant in over 1000 locations across the country, including the organized wholesale markets of ISO New England, PJM, NYISO, Ercot, in addition to a 2008 direct pilot with CALISO. We have energy monitoring equipment at every location in the U.S., and advanced metering systems of our own at over 1350 locations.

We are extremely pleased FERC concluded that Demand Response should be considered as comparable to generation. While recognizing the many benefits that DR delivers to market, it is also important that participants receive fair and comparable compensation for these services and benefits provided to the marketplace as a whole.

Participating in DR resource consumers, we do make sacrifices to supply DR service of curtailment. Consumers make payments for aggregator services. We sacrifice the comfort, convenience of family members in our homes, and the associates working within our businesses;

consumers shopping our stores. We make adjustments to our manufacturing schedules, employee shifts, and invest in DR equipment to make these results happen.

In addition to the obvious benefits of reducing LMP, this is a nonexclusive list of benefits to ratepayers of the overall market. We supply GHG-free curtailment, which could also reduce possible ratepayer penalty payments from carbon-constrained LSEs and generators.

We decrease the need for some ratepayer funded peaker plants. We lessen transmission congestion. We better consume management of energy consumed in our facilities, lowering the power purchased for any time period.

From Wal-Mart's perspective, a DR resource owner can benefit environmentally and economically, but not without sacrifice. From investment in our own cost recovery tool, which improves environmental and efficiency goals, both helping ourselves and our consumers to save money in the long run.

As noted in PJM's recent report, DR participants significantly reduce prices, peak prices, in the market. But value cannot be fully quantified just by looking at its effect over a five-minute, or one-hour time span. The value of DR also must be recognized over the long term, and even more as more DR occurs to fully appreciate its many potential benefits.

The Commission has asked how DR cost resource participation should be allocated. While respectful of the ISO/RTO efforts and the vast number of transactions in these markets, DR should be treated as comparable to generation resources pursuant to Order 719. An entirely new process should not have to be invented from scratch.

In our opinion, it should be the Commission's policy that payments to account for DR resources should be charged in the same way that payments for generation resources are allocated to consumers.

As benefits are enjoyed by the market in a more global, or at a minimum a zonal sense, and consistent with the Commission's long-standing and widely accepted cost causation practice, the Commission should adopt the basic concept that costs should be allocated where the benefits are received, just like generation.

For example, it has been said that the billing-unit effect of dispatching DR as a source of settlement difficulty presents a "missing money" problem. However, we look forward to understanding more about what this "missing money" consists of, and if in fact it should be an issue.

If it is, a settlement mechanics' issue can be addressed through proper accounting that is not fundamentally different from other deviations properly settled by the ISOs and RTOs.

Finally, our proposed approach ensures that other market participants such as generation resources and LSEs are indifferent from a bidding and settlement perspective as to whether the load is served by generation or DR, or even whether DR is present or absent in its consumer base.

In summary, Wal-Mart welcomes the Commission's actions toward greater participation and more comparable treatment of DR resources in the Commission's regulated wholesale energy markets.

Wal-Mart respectfully requests that the Commission adopt a Cost Allocation approach that recognizes the many and widespread benefits of DR, and allocates the DR service costs in a manner comparable to that used for generation resources, and in a way that ensures that all the costs should be allocated where the benefits are received.

Wal-Mart appreciates the opportunity to participate in this proceeding and the ability to supply curtailment services in these wholesale markets. This contributes to a cleaner environment, and benefits many customers in many ways, which also helps us to help them save money and live better.

Thank you.

MR. HUNTER: All right. Thank you. Next we've got Megan Wisersky from Madison Gas & Electric, and representing the Midwest Transmission Dependent Utilities.

MS. WISERSKY: Thank you for the opportunity to speak today on this NOPR.

I am representing MG&E today and the Midwest TDUs. MG&E, Madison Gas & Electric, is an investor-owned public utility under the laws of the State of Wisconsin, and we are regulated by the Public Service Commission of Wisconsin, or I'll probably call it the Wisconsin Commission.

Among other things, we provide electric service to about 140,000 customers, residential, commercial, industrial, in southern Wisconsin. And our highest peak--wait for this--742 megawatts in 2006.

I'm also speaking on behalf of the Midwest Transmission Dependent Utilities, or TDUs. We're a group of transmission, like I said, dependent utilities, and we are all members of the Midwest ISO. I also would like to put in the plug that we're all from traditionally regulated, cost-of-service, obligation-to-serve type states.

I was going to actually in my comments today go off on a slightly different direction supporting--and we do support--the MISO approach. But really the big elephant in the room that hasn't been addressed, particularly in what I heard in the morning panel, is the role of the states.

When it comes right down to it, it is their--they are the key decision makers for us in regard to Demand Response. They allow us to participate or not participate. And the whole compensation issue for us, and especially with our utility demand programs, is all developed through our ratemaking process through our rate cases, and such.

So from our point of view, paying full LMP instead of doing something like LMP Minus G, we're talking about subsidy, in our opinion. And if there is a subsidy, none of the Cost Allocation proposals will work. They all have problems because it doesn't deal with the "missing money" problem appropriately. And, as mentioned in earlier panelists, we believe that actually will retard Demand Response development, particularly with utilities such as MG&E.

And also, because we are in the Midwest ISO dominated by traditionally regulated states, that regional variation and experimentation, instead of one-size-fits-all policy, is very important.

Let me--I have already mentioned, probably used and abused MG&E's DR program a little bit already--these aren't new programs. We were first directed to create these in 1984, and they are meant for reliability purposes, and they've served us very well.

We have about 50 megawatts of Demand Response split roughly into two different types, a commercial, industrial interruptible program, and these customers through the rates are paid a monthly bill credit.

They also get a bill reduction if we do interrupt them. They are not consuming energy. And the other 25 megawatts, roughly--it's a residential air conditioning program, and these customers are compensated when we actually use the program.

Now what our Demand Response programs represent is basically--this is nonfirm load. We don't do planning for them. And this has allowed us to--you know, at 50 megawatts that's roughly, you know, it's a small peaker that we haven't had to build or go into a purchase power agreement with someone.

And we use these programs in the Midwest ISO both in terms of the ASM market, the ancillary services market, and we're in part of the Emergency Demand Response.

The Commission's actions on this NOPR we believe should be guided by Order 719A, and that the Commission was not intending that existing Demand Response programs, whose benefits are well known, would somehow be endangered or put on the chopping block.

I would say that we support the MISO-type approach to this, which is essentially LMP Minus G, because we believe if you do that, make that adjustment, you can assign the cost of that DR to the utility and you don't socialize or uplift these costs to any other customers.

Given this Commission's limited role with respect to retail Demand Response, we think it makes sense to allow the RTOs to work with the state regulators to develop DR compensation and Cost Allocation policy that meets the needs of the states that are in the region, such as MISO. And MISO is very different from the New York ISO, ISO New England, PJM, and such.

So as long as you have this "missing money," if you're going to socialize or uplift this cost, the allocation process just does not work properly. One of the things that at MG&E we kind of, we jokingly say is "load always pays." I don't care how you--if you charge transmission owners or such, somehow, you know, all that money gets funneled back to load. So that's where it's very important to consider the compensation in DR and how it affects utilities and the customers of utilities such as MG&E. Because--and this may sound a little vulgar, but it in our mind is just basically wrong to stick the G costs to the LSE.

So in conclusion, we believe that standardizing the compensation and Cost Allocation is not warranted at that time. Like I said earlier, one size does not fit all. And the Commission has had a long history of allowing regional variation to meet regional needs and conditions, and we hope that the same philosophy will continue on in this NOPR.

Please welcome experimentation and keep an open mind to different types of compensation and allocation designs. Thank you, and I look forward to the question and answer period.

MR. HUNTER: All right. Thank you. And next up is Jay Brew from the--counsel for the Steel Manufacturers Association.

MR. BREW: Thank you very much. You've finally reached the end of the line.

(Laughter.)

MR. BREW: The Steel Manufacturers are very grateful for the opportunity to speak here today. We are the trade group for North American steel makers that use electric arc furnaces, primarily, to recycle scrap.

SMA's 34 member companies operate 125 steel recycling facilities in North America from California, to Iowa, to New York. Today about two-thirds of the steel made in America comes from EAF-based facilities.

Now a steel-making facility has always been about efficiently producing tons. That being said, SMA's members operate under interruptible-service rates, or in the Demand Response programs in both the organized and fully regulated markets.

We have become sort of the Exhibit A of how Demand Response can work, and that requires a little bit of background.

A typical electric arc furnace load is between 50 and 200 megawatts, that operates a batch process that takes about an hour from when you dump scrap into the furnace to where you tape a molten heat. And through the years, with the proper equipment, with the right investments, we've been able to disrupt that process in order to participate in these programs.

There is a cost. If you've ever been to a steel mill, you do not want to interrupt that process. But we have. And have many times been able to curtail our loads on less than 10 minutes' notice, and certainly under the time frames that would make it comparable to or better than a typical peaker in terms of ramping up and supplying very reliable Demand Response into the market.

From a system operator's perspective, it is among the easiest loads to verify performance because they can see when the furnace goes off.

Importantly, as I mentioned, we operate in fully regulated markets. We may take service under average embedded-cost rates, or hourly rates. We may operate in states that have retail competition--for example, in New York the default service is a mandatory hourly price. That means little, because a load can and will hedge some or all of its load. It may be around-the-clock. It may be for peak periods. It may be I adjust my load during certain times for how much is hedged. The bottom line of which is that I think the Commission correctly recognized here that how service is priced at retail is, one, something over which it has no control; and two, is not really relevant to the value of what's provided to the system operator. Which is that a reduction of 50 megawatts physically has the same value as an addition of 50 megawatts supply for a system operator that's trying to keep the system balanced at 60 hertz.

Since at least 2005, SMA has been advocating for the Commission to take a leadership role on Demand Response. You have to appreciate from our perspective. Before a steel manager considers whether to participate in a Demand Response program where he's going to cut off his process in midstream, we have to get through our local utility, every relevant committee at an ISO, state regulators, and the Commission.

It is an amazing gauntlet to try to see any major changes come through. So I would like to strongly emphasize the statements you heard this morning that, particularly on Cost Allocation, as well as basic compensation, that the Commission exercise its leadership prerogatives and send either--establish a uniform policy, or provide as much guidance as it can.

From a Cost Allocation perspective, I urge you to take the mystery out of it. Treat this as though you would a generator step-up transformer. There's no reason for the Cost Allocation of DR compensation to be a real mystery. The benefits, as we've talked about all morning long, relate to the energy markets.

The beneficiaries are anyone who is participating in that energy market, not simply in LSE. And so that is the basis upon which you should allocate those costs, which is to role them into the Day-Ahead prices.

Next, with respect to the other questions that have come up on Cost Allocation, there's a basic distinction between rate design and Cost Allocation where a lot of the questions roll over into how mechanically do we do that?

That's where I think you could look to what's already been done at some of the ISOs. But it doesn't really change the basic nature of what are the costs involved, and how should they be allocated? Those are the key questions that the Commission needs to get to.

From a--just to sum up, this proceeding is really about the Commission having the determination to do something about a problem that it has, which is that you don't have supply and demand interacting around price on the wholesale markets.

The Commission should be accepting things that it can't control, which is how, when, and if the pricing of services at the retail level change. The real problem you have with the wholesale markets isn't your inability to control retail prices; it's that you don't have storage, and you don't have retail prices. And, as Dr. Hogan mentioned earlier, that's why we're here. But that's a given. The question is: How do we move forward from here?

And so what we're asking for is that the Commission continue to exercise a leadership role, that it not push these basic decisions downstream where the transaction costs to consumers to participate is exceptionally high, and that it move forward with a policy that is articulated in the NOPR.

Thank you.

MR. HUNTER: All right. Thank you. Thanks to all the panelists.

Anything from the Commissioners before we get started?

(No response.)

MR. HUNTER: Okay, well I guess I will start with, to put you on the spot, Tim Brennan from National Grid, with a clarification that might lead to some more questions.

You talked about basically paying full LMP when Net Benefits exceeded, or the benefits exceeded the costs, the Net Benefits were positive, and the LMP Minus G in the other hours was basically National Grid's position. And you also said that as long as costs paid to the DR resources were allocated entirely to the load-serving entities, then it would be an accurate or an efficient Cost Allocation mechanism.

The question is: Did that depend on what hours we were talking about? Is that all the time? Or was that then a Net Benefits is positive, so the LMP price kicks in? It's just a clarification.

MR. BRENNAN: Yes. And and I think, to add a little more detail, which we did in our May comments, while we supported the full LMP in some limited hours, and basically when you really get a big bang in cost savings for the entire market for the buck that you pay, or the extra buck, as some might even argue, there also needs to be an additional limitation on that.

So in other words, not just passing such a test, but also taking in mind, which we've heard, the baseline consideration. We do want to make sure we're paying for actual, not simply apparent Demand reductions. And there are problems, if someone is bidding and clearing, and if you don't do it right, I think there are ways to correct for it, or even if you allowed people to bid all the time, there have been some proposals in the stakeholder process that would still allow that, but supposedly take care of the static baseline.

But I won't go into a lot of detail, but I think a lot of you know what the baseline issue is. If someone appears like they're always at a certain load, and then gets paid, when they actually didn't lower their load at all. It's very important for the monitoring and verification not to have a static baseline that you end up paying for apparent rather than real demand reductions.

So, you know, not simply a Net Benefits test, but a Net Benefits test that works. And maybe it needs to be limited to certain thresholds due to that baseline problem.

Once you decide on that, though, National Grid's position is that the compensation needs to go to the wholesale market in some way. And I want to stress that. Sometimes I've seen in past Commission Orders, and also in some of the comments in this proceeding, if you're going to pay the full LMP, a lot of people accept that the LMP Minus G portion goes to the load-serving entity which saw that load reduction.

Doing that, mathematically you can show in the long run they are neutral. Now if you're paying the LMP, there is that additional portion that hasn't been allocated with the LMP Minus G. That's the G. And you see some comments and some people saying, well, that portion, and I agree, isn't--it's not appropriate to send that portion also to the LSE alone; it should go to all load.

But what I've seen in some past Orders, and even in comments here, is once you make that decision that we should put some portion of the cost to, quote, "all load," I think some people make the mistake that the only way to do that is to all transmission load. In New England we have the term called "network load."

But I want to make sure it's absolutely clear that if you want to target something to all load, you don't necessarily have to jump to all transmission load. You can still go to all wholesale market load. It's the same megawatt hours.

Network load in New England, if you have 20,000 megawatts of network load in New England in a certain hour is 20,000 megawatts of real-time load obligation in New England in that hour. But the difference is that those with the real-time load obligation have agreed to take on all wholesale market load-serving obligations and all the costs associated with the operation of the wholesale energy market.

So depending on the compensation, I believe some costs should go to all load. But still, even those costs, the all-load should be the all wholesale market load.

MR. HUNTER: Thank you.

MR. QUINN: Can you address kind of the argument ISO New England made that if you allocate to all wholesale load that that's going to end up getting kind of a rate-of-return adder added on to it, kind of through the competitive market forces? But if it goes to say all transmission load, that's just a straight pass-through for state rate-making purposes, so there won't be any adder? So there's kind of a rate-making advantage to going to the transmission loads versus the wholesale loads?

MR. BRENNAN: Yes. I think the first thing you need to focus on is getting the compensation right. As I mentioned, there's different opinions on what that right compensation, correct compensation is.

When the ISO New England makes a statement like that, that is because they believe that the additional payment is inefficient, is not helping the operation of the energy market at all, and in fact may be increasing the costs of the wholesale energy market.

So when they make--the reason then for saying send those costs to the transmission charge is backed by that reasoning. So first of all we have to try to get the right compensation level. And a Net Benefits test I think can go to that.

To say that you could just simply pass the costs to transmission customers and avoid the risk premium, you can say that on most any charges that are at all related to the operation of the energy market. We have NCPC, or Uplift compensation that isn't directly reflected in the clearing price. But we believe that's a required cost of an efficiently operating energy market.

We don't say take those costs and put them on the transmission customers simply because the load-serving entities won't have to worry about those risk premiums.

If you get to the point where you still convince yourself, well, I'm not sure whether it's the real efficient cost that should be allocated to load-serving entities; it would be cheaper to just go directly to transmission customers, I'm not sure I even agree with that. Because the promise of the markets were that we would have competitive suppliers who would react to transparent pricing in the market. They would come up with innovative ideas, competition. The sophisticated merchant suppliers would figure out how to handle these costs associated with the operation of the energy market.

So if we're going to now start saying, well, there's an additional risk premium, at least in the short run, it looks like we could avoid by allocating the transmission charge, I think, you know, that's really giving up on the promise of the markets and it's taking away from the innovative possibilities of the people who have decided to take on the wholesale load-serving obligations.

MR. HUNTER: Thanks. Any comments related to that line?

(No response.)

MR. HUNTER: All right. I'll come back to you, Tim. I heard a couple of people mention the term "missing money," and again I want maybe a clarification here that may generate some discussion.

I think the standard understanding of that term is that when you have Demand Response providers being paid full LMP, unlike the case where you have buyers and sellers and for every megawatt that gets bought there's a seller providing it and the money gets matched up, pretty clearly here there is this "missing money", the money that is not being--there's not a buyer that's paying for this energy that's not being consumed.

I heard a couple of people mention it. I think Angie wasn't sure it existed. I just want to make sure we're on the same page with what it is. And, if so, how those costs should be allocated.

So any thoughts on that? Thank you.

MR. SCHISLER: Well--Ken Schisler--the "missing money" problem, the moniker troubles me, because we've used it in regulation. It can mean a couple of different things. But essentially it occurs to me that, depending upon how you do Cost Allocation there can be a settlement imbalance.

You heard this morning from Mr. Sipe. In his, the Consumer Demand Response Initiative's algorithm essentially eliminates the "missing money" problem, if you will, the settlement imbalance, by allocating the load to cost to making sure that at the end of the day it's always, by definition, producing benefits to customers.

But where you have a condition where the supply stack includes both a Demand Response and Generation, and then at the end of the day there is only a certain amount of megawatts that are billable, you have fewer megawatts that are billable than the total supply that has to be paid for for supply in the form of Generation resources and in Demand Response.

So other mechanisms include sort of to recover that as an Uplift charge, recognizing that Uplift again will be providing, essentially purchasing a $5 for $3. You're providing a Net Benefits to customers. So that Uplift cost is resulting in benefits to customers. But you have to collect the $3, referred to by the "missing money", from somewhere.

And there are means to do that. Mr. Brennan was talking about those. You can collect them from all load-serving entities within the zone. You can collect them from all load-serving entities in the system. To buyers in Real Time. I can run it in the Day-Ahead market, as well.

So you have to collect that cost from somewhere. Our comments were that you shouldn't collect that cost strictly from the LSE, the host LSE. Because what that would do is create a condition where, while the benefits are enjoyed broadly by the market, the LSE of record would be paying for a disproportionate share of those benefits.

So it is not consistent with kind of a beneficiary pays approach. That's why we favored a broader-based way to capture that missing money.

MR. HUNTER: Yes, Megan, please.

MS. WISERSKY: Thank you. I was thinking of it as very close to what Ken was saying, that there is a mismatch between the amount of megawatt hours we as an LSE are charged for and what our retail meters show that were actually consumed. So it's missing megawatt hours with associated rates that we would have received, or revenues we would have received as the LSE.

So that's the mismatch for us. And it gets back to--and it was stated this morning--that what the demand responder is doing by paying the retail rate is essentially buying from us a service right, that it's in turn selling into the wholesale market.

And from our point of view, if that is done, if we are compensated for that, then it becomes, when we're talking about broader Cost Allocations, it's almost that then you're dealing with a resource that's almost more like a generator that's within your service area.

So then, if you look at the ways LMPs are constituted, then, yeah, the LSE that's within that area, because the prices of that generator are going to affect the local LMP more so than--you know, in Madison than they are somewhere in the far reaches of southern Indiana.

So then in that case, if you reconstitute the load as what Mike had said, you--the host LSE--the cost of the DR can be allocated to the host LSE.

MR. HUNTER: All right, thanks. Carl?

MR. SILSBEE: I agree with Megan's definition of "missing money". Let me give a simple example of where I see the problem.

Let's say that we have a 500 kW customer, and that customer has contracted with a Demand Response provider to supply 400 kW of load reduction, and bids it, and it's called. Under the way the PDR works in California, the customer would reduce load to 100 kW, but we as the LSE would still pay, or be responsible for 500 kW in wholesale markets. And we're okay with that. We probably had planned and bought power to serve that 500 kW in advance.

Where we run into problems is, we'd also planned to get 500 kW of payment at retail from the customer. And now the customer is only seeing meter spin of 100 kW. So there's 400 kW of retail payment that we didn't get. And that's why we're looking to the state to find some way to compensate us for the loss of compensation at retail, the Minus G.

MR. HUNTER: Thank you. Michael, from Midwest ISO, you had some thoughts?

MR. ROBINSON: Sure. Thanks. Yes, Carl looked at it from the retail point of view.

Let me address it from the RTO's perspective. What we're trying to do is conduct these markets in an efficient and competitive fashion. We have two constraints that we have to operate under.

One is that we're revenue neutral. So whatever we take in, we flow back out. So we need to have enough money to do so. And that's really the source of the "missing money".

The other is that we have to meet the energy balances 24/7. So if you do a really simple example of suppose we're in a high growth period here, a morning ramp where load is growing, and so we're sitting at one dispatch interval and we think that we're expecting the load to grow 100 megawatts in the next interval.

In a world with just generation we could dispatch the next two least-cost generators, say 50 megawatts each, to meet that load. Okay, we meet the energy balance. Load goes up 100 megawatts. Electricity injected by the generators is going up 100 megawatts. And the generators get paid LMP and the load pays LMP. No worries. Energy balance and revenue neutral.

Now you throw in DR as a resource, and out of that 100 megawatts of load growth, 50 megawatts is coming in also. So, well, I'm normally going to consume over the next dispatch interval 50 megawatts, but I've offered you in as a load drop, if you pay me.

And so if it's in the merit order stack, load would of went up 100 megawatts and only goes up 50 because we called on the DR asset to now show up, we still--the DR asset by not showing up doesn't inject electricity into the grid, we still need to use the generator, the 50-megawatt generator to meet the energy balance.

So the load is paying based on 50 megawatts of additional withdrawals, and we have 100 megawatts of resources that we have to pay. That's the source of the missing money from the RTO's perspective.

MR. HUNTER: And from Consumer Advocate, Sonny?

MR. POPOWSKY: Yeah. First of all, and perhaps I should have said that, it has to go without saying that the

DR shows up. And that was--when we filed our comments in support of the Commission's proposal for paying LMP, the second part of our comments was the importance of measurement and verification to make sure that what we're paying for we're actually getting.

So I think that has to go without saying for this whole conversation. But if you accept that, if you accept that the guy shows up and that the DR provider comes in at a price that is less than what it would have been for the next incremental generator, basically the way I look at it is it's a question of arithmetic.

You're sort of keeping the numerator the same, but the denominator is going down. So if we're talking about dollars per megawatt hour, and we reduce the denominator because we're selling fewer megawatt hours, well we have to make that up.

And the way we make that up--I think this is what Mr. Sipe was talking about this morning--but I think the way we make that up is we have to charge slightly more to all of the megawatt hours that are in the wholesale market at that time at that hour.

The reason I'm willing to pay slightly more as a consumer advocate is because it's still less than we would have had to pay if we had brought on a higher cost generator, and that higher cost of generation was then spread over all those megawatt hours.

So I think it's a question of arithmetic. And I think the best way to do it is to spread it to all of the load in the market--and I'm talking about the wholesale generation load, not the transmission--but to spread it over all that load, because they are still better off and they should pay for it.

MR. HUNTER: Thanks. Commissioner?

OHIO COMMISSIONER CENTOLELLA: Well I wanted to both agree with Carl's characterization of what the "missing money" problem is, but suggest that it is really not tenable to put that responsibility back on the states.

I mean, the ultimate, you know, fact that, you know, what Carl's illustration demonstrates is that you really do have a subsidy or an incentives which goes beyond what is efficient in terms of the payment to the Demand Responder in this instance.

And you are now putting the state in the position where if we were to try to get back to an efficient level of incentives, we would be having to in effect issue a charge for energy that was not consumed. We would be doing what would be perceived as a take-back by that customer. And that would put us in a very difficult position.

Alternatively, I suppose we could, if it were subject to our jurisdiction, spread it to other customers of that utility. But it may well not be subject to our jurisdiction. It may be a competitive LSE for which we have no authority over it, in which case the LSE may simply end up being squeezed in that situation based upon their existing contractual commitments.

So I think that, if one wants to make this clean and transparent, the right thing to do is to get the incentives right at the wholesale level by doing LMP Minus G. And not attempt to force it back onto the states to correct what is in effect an untenable kind of situation.

So I guess the question then becomes: Does the additional incentive of not recovering G, is this a sensible incentive from the standpoint of promoting increased Demand Response? And I would suggest that it is not directly related to what's necessary to incent additional Demand Response. It may be more.

It may in some instances even be less than what's necessary. But it is directly tied to whatever that customer's retail rate was, and not to some specific either market failure or other policy objective that you're trying to incent by incenting more Demand Response. What you're doing is you're creating incentives which vary by customer based on what that customer's retail generation rate is. And it is not clear to me why that additional incentive is at all rational.

MR. HUNTER: Thank you. Commissioner Moeller?

COMMISSIONER MOELLER: Thanks, David.

I want to get back--Carl, I must be missing something in your example. So as the LSE you are still required to procure the 500 kW. The DR provider bids in the 400. But isn't it in your interest then to resell that 400, in which case there hasn't actually been a decrease in demand?

MR. SILSBEE: We run our own Demand Response programs where we seek reduction from the customers, but at wholesale Demand Response providers are free to enter that game as well and may participate.

If the customer wants to go to a third party Demand Response provider, that's fine. That's their choice. We stand by to serve them the 500, if they want to pay for it. We also appreciate the importance of a price signal. And if they want to reduce their usage by working through a Demand Response provider, we have no objection to that.

As I said in my prepared remarks, everything balances out. It's Minus 400 from the DRP with the participating customer behind them, plus 400 on our books, and the LMPs work out as well.

What we want is to get a retail payment back from the DRP or the customer. The mechanism by which we do that is still something that we hope the California Public

Utilities Commission will address.

And I realize that retail payment at the specific time in which the DR payment--or the DR Program is called, may not be the same because of the blending of the rate, and perhaps the socialization of that rate. But that's really an issue with state ratemaking that needs to get sorted out by the state, in my view.

COMMISSIONER MOELLER: Okay. Thanks.

MR. HUNTER: Okay. Angie, you've been very patient. Thanks. Go ahead.

MS. BEEHLER: As we're talking about this being compensated and the "missing money", it seems very comparable to decoupling that's happening among the states. And we believe decoupling can be done through rate design. And so I don't see why this decoupling could be done at the ISO level through the ISO/RTO with their settlement process, putting fixed cost, variable cost.

But also another question I have, as I'm trying to think through this, is our country is moving more and more towards renewables. What if I put solar on 10 of my rooftops that's going to be in effect next month? How does the ISO--and I'm not real familiar with this--but say I'm going to put onsite solar on my rooftop on 10 locations within a LSE's territory, how does the ISO allocate for that?

And then I think it's real important that customers have a choice in these programs whether to go in whatever route they want to go to through the LSE, or through the RTO. Because there are also other costs for customers at the LSE area. For example, program costs for a DR program; incentives; decoupling to keep them whole in some areas; and penalties for performance, and incentives for performance at the local level.

So I think it is important for customers to have the choice of what DR program works the best for that customer and their home, or that business, and have the right to look at which ones are really going to work for that customer in their home, or their business.

Thank you.

MR. HUNTER: You're welcome. Yes, Jay Brew from the Steel Manufacturers.

MR. BREW: Just to chime in a little about this. I wanted to distinguish what I heard Ken talking about, which was in terms of the reduction in load relative to the payment for DR compensation and other issues, such as loss revenues from missing sales.

Remember, there's never a load factor obligation. There's no rate where a customer is obliged to acquire certain capacities. Recovery of fixed costs is usually addressed through capacity charges or demand ratchets at the state level. But what the customer's load factor is, or whether they go up or down is, I mean, is entirely separate from the issue of fully recovering the cost of the DR compensation program.

MR. HUNTER: Thanks for that. Megan?

MS. WISERSKY: Thanks. I just wanted to chime in about how important this "missing money" has been to the Wisconsin Commission. The Wisconsin Commission--let me get my words right here--they temporarily barred the participation, the direct transfer of DR into the MISO market, or the operation of a third party arc, mostly because although they recognize there might be some advantages, they were very concerned about any discriminatory effect that this might have, and the financial implications to ratepayers, the electric utilities.

And how we plan, or how we do our long-term planning, is I did mention that our utility-based programs are nonfirm load that we don't carry reserves. So there is a question about what happens to that if you cut that Demand Response loose from the LSE in this type of regulated state, what happens to it?

And I'm just quoting now, it's--the filing for that was, or I'll paraphrase it: The Wisconsin Commission was concerned about this approach could end up, or had the potential for securing electricity at net lower rates than are authorized by the commission. So the Wisconsin Commission did recognize that there is a, potentially a "missing money" problem that could arise.

Thanks.

MR. HUNTER: And Michael from the Midwest ISO has had it up for awhile.

MR. ROBINSON: Sure. Thanks. I wanted to support what Commissioner Centolella was saying earlier about how, if you sort of let this get sorted out at the retail level between the state jurisdictional authority, the LSE, and the third party provider, there could be some significant issues from either a statute basis or just some significant problems.

The Midwest ISO recognized that. And so in our original proposal, as I mentioned earlier, we did support paying LMP and then charging the LSE LMP. And letting those monies that flow between the counterparties, the third party provider and the LSE, get sorted out at the retail regulatory authority level.

We heard loud and clear from the organization of MISO states and other retail jurisdictional entities about all of the issues that would be associated with that, and the problems. And so--and in addition, we recognized that we had certain efficiencies and economies where we could actually accomplish that much cheaper than the state jurisdictional entities.

So in our final proposal we offered to provide that service to essentially--we didn't call it the G, LMP Minus G, but we called it the "Marginal Foregone Retail Rate" to recognize the fact, as Paul said, that the retail, the avoided retail revenues could vary by market segment, by market participant, by state, by utility.

So we have the tools in place currently to accommodate whatever the Marginal Foregone Retail Rate would be as specified by the retail regulatory authority.

MR. HUNTER: Professor Hogan?

PROFESSOR HOGAN: I would like to come back to Commissioner Moeller's question and come at it a slightly different way and pose a question.

It seems to me--and also to deal with Paul's concern, which I think is legitimate--this is a FERC program. We're talking about wholesale market Demand Response participation, which people volunteer for. They're not required to do it.

So I don't understand why FERC can't condition it and just take a very simple model that, it seems to me, would work. Which is that, you can sell into the wholesale market any electricity you've purchased. If you purchase electricity and you don't consume some of it, you can sell it back and we'll pay you the LMP. But you have to purchase it. So now it's a contractual arrangement, and they can purchase it on their whatever-arrangements they have. They can get it through their retail rate. They can do it with their competitive load serving entity. They generate it themselves. And then we'll purchase it back at LMP. Now we can all go home.

Why couldn't FERC do that? That would be efficient. It would be simple. There'd be no Net Benefits test. There's no Cost Allocation. It's consistent with all the rhetoric about even-handed participation in the marketplace. We're done.

MS. SIMLER: Maybe we can hear from some of the Demand Response folks? Angie?

MS. BEEHLER: The only issue I have is, it's really--we aren't selling energy back into the market. We are providing a service of curtailment. We are choosing, and making a sacrifice in our stores, and providing a service. So there's no "selling" of anything back into the market.

I see it really as a service, a service that we're providing. We're curtailing our load. We're paying our people. And so it's different, but it provides a good purpose. And it does a lot of the same things as generation does. However, there are many benefits that provide and come to many ratepayers. But I don't see it as selling electricity. I see it as providing a service when it's needed. Or, whenever we need to contribute.

Thank you.

MR. HUNTER: Ken.

MR. SCHISLER: I guess I would add to Professor Hogan's point. FERC certainly could do that, require sellers of Demand Response to purchase and then resell.

Effectively that's what we had in PJM that led to the PJM Board of Managers deciding that that model, that regulatory paradigm, failed to elicit sufficient Demand Response resources, and that as a result wholesale rates were not--there was insufficient penetration of Demand Response.

So it can work. We could do that, and we can all go home, but we will also have inefficient levels of Demand Response in the market. If we're willing to accept that, then we can again--we can achieve what Professor Hogan states, but that would also ignore the requirements of the Federal Power Act that we have Just and Reasonable Rates at wholesale.

If we have an inefficient market because we do not have Demand Response, we have to correct for that. And gain, we could do it, but it just simply won't work because we've had the ability to do that forever and we have Demand

Response under-penetrated in the market.

MR. HUNTER: Jay, you wanted to add something there?

MR. BREW: Yes, I guess the short answer would be Demand Response is not a fake sale followed by a fake resale. It is, given the circumstances in the market, am I willing to incur the cost of disrupting my process, which otherwise was going to run 24/7, in order to provide verifiable reductions?

You may have trouble with what are those underlying costs for a generator's fuel, and rampup, and others for the load is a different set of costs. But it's not a series of assumed sales. That analogy just doesn't work.

So the question is: If I'm willing to cut 50 megawatts at two o'clock when I otherwise wouldn't, I can run a model which figures out what fixed-cost per ton do I have to recover? And I can convert that into a strike price. So that I can then say: At this price I'm willing to curtail my operations.

The value to the system operator is, are those 50 megawatts real? Are they going to be there at two o'clock? And that's what the basis for the compensation is. Most of the discussion that's gone on earlier is the value of that 50 megawatts reduction, if it's verifiable, is the same as adding 50 megawatts of supply.

So the problem I have is with the construct: saying that I have to buy the energy first is simply compensating the LSE for lost revenues. It's a different matter from the value of Demand Response to the system operator.

MR. HUNTER: Carl, you had something to add?

MR. SILSBEE: I wanted to come back to this issue of Minus G at retail versus wholesale. I certainly didn't want my comments to be taken as preventing an ISO or RTO from cooperating with its state jurisdictions to implement some kind of a Minus G adjustment.

I realize that there are significant differences between an ISO that serves one state, as in California, and an ISO that serves multiple states and may have significant issues of trying to rationale a Minus G policy when states may themselves have different retail policies.

So this may be an area where FERC would want to play very careful in crafting rules that recognize regional differences.

MR. HUNTER: Megan's back.

MS. WISERSKY: Thank you. Before I launch, I'm going to say that I am very supportive of Demand Response but I'm a little confused at this moment. Because it seems I'm seemingly getting the idea that being compensated at LMP is not enough.

And if that's the case, meaning that, sandwiched as I am here--

(Laughter.)

MS. WISERSKY: I've heard that it's not an energy purchase, but we're participating in the energy market. So forgive me if I'm slower than the rest of you in the room, but we're in the energy market but this isn't an energy sale or purchase? So I am really lost at this point.

Forgive me if I'm rehashing maybe some issues that have been settled in the past and I'm just ignorant of this, but to me for a Demand Responder to offer into this wholesale market, for me as the LSE sitting here, they have to buy that right from me. That right has value.

And once they have bought that right, they're free to sell it at LMP. And so that's--so they do see the full LMP cost, or price spindle, and I appreciate, because I know that we deal with process-oriented customers who are interruptible, and I understand it is a pain for them to interrupt, and they have to clear out their molds and all that and make sure that nothing sets up and causes a big problem, but that's all part of their business model.

They went into our Demand Response Programs with their eyes wide open. They understood what type of credits that they were going to get monthly, whether they're used or not for their Demand Response.

Their business model supports this. So I'm beginning to get--so for me it seems like in order to--and again, I apologize if I'm coming across as being very stupid at this point, but it seems like that I'm getting this message that it has to be LMP-plus in order to incent DR to be in this wholesale market. And that is very different than generators, and it is not at all comparable.

Thanks.

MR. HUNTER: Jay, did you want to respond to that?

MR. BREW: Yes. The only clarification I would give is that, for example I can think of one instance in an organized market where I have INISO, who's my LSE, and I have a curtailment service provider that we sell our curtailment into. Those are separate transactions.

The LSE is not entitled to any compensation if my load drops because I'm participating in a ISO call. So it can be confusing because it's not as simple as the old retail Interruptible Rate, but that's the nature of the wholesale markets.

MR. HUNTER: Any more? Thanks, Commissioner.

OHIO COMMISSIONER CENTOLELLA: I want to go back and comment on one thing that Ken said, because I think actually, Ken, you said something that I agree with, and I want to--but I want to take it in a direction which may not be the direction that you intended it.

You said that we have inefficient markets when it comes to Demand Response, and we ought to do something to correct that inefficiency. And I would agree. You know, there are inefficiencies in the fact that, you know, we don't have the measurement to do Demand Response in real-time for many consumers.

There are information asymmetries. We have consumers who don't even know what a kilowatt hour is, let alone the fact that it could cost more on-peak than off-peak. And, you know, there are things about the demand side of the market that are inefficient.

Where I have a problem is I don't see the payment of LMP plus the avoidance of the retail generation cost as being somehow linked in an efficient way to correct those inefficiencies.

If we were having a different discussion today about who should be paying for advanced metering, or who should be paying for information displays that allow consumers to know what it cost them to buy electricity which are the kinds of debates that we have in our state, this would be a very different discussion I think.

But I know, you know, the issue is that we've kind of latched onto this notion of paying full LMP plus avoidance of the retail generation charge, and we have not asked the question of what is the most efficient way in which we as regulators, or we as market participants, could overcome the specific reasons why the demand side of the market is less efficient than we would like it to be.

And I think it would be much more productive for us to have that discussion than for us to have this discussion of paying full LMP versus LMP Minus G.

MR. HUNTER: Thank you. With that, let me go back just to a point that Ken from EnerNOC made in his opening remarks. Basically the argument was, and correct me if I'm wrong, but the benefits are broad-based and therefore the costs ought to be allocated in a--broadly allocated.

Do you want to say anything more about that? Or does anybody want to have any comment on that basic sort of fundamental point?

MR. SCHISLER: Well as Sonny Popowsky pointed out, the essence of the argument was made amply by NECPUC in their comments. And I refer in my comments to the PJM list, because they set it out--not to compliment PJM necessarily, but they set it out as a series of options. And they pointed out how one option which allocates all the costs back to the host LSE. And the second option, which is allocate essentially LMP Minus G to the host LSE, and allocate G, you know, socialized in some fashion. They sort of laid all of those options out.

Those options that allocate those costs to the LSE leave the LSE, both of them leave the LSE not indifferent to the transaction. And that raises a whole other set of concerns for us, in that you have arguments over what G ought to be. You have arguments over when a settlement gets submitted, you can have wholesale rejections of settlements by an LSE--because, again, they are not indifferent anymore to the transaction.

So we suggest that the idea of charging it to the host LSE raises this other set of problems, but it does result in a set of problems where, if you had an LSE that was in the same zone that got the pricing benefits of the lower LMP as a result of a DR participation, so you have two LSEs in the zone, one of them, the customer is the arc provider, is behind one of the LSEs, you charge that cost to that host LSE, you've lowered the system cost in that zone. The other LSE gets the benefit of that but doesn't have to pay for those costs, the costs of getting that Net Benefit. So therefore we suggested that the cost ought to be shared more broadbased to at least all of those LSEs in the zone.

MR. HUNTER: Thanks.

MR. GOLDENBERG: I'd like to follow up. I had a question along the lines that the LMPs generally are not the same throughout the system. They can vary, and sometimes they are, but sometimes they vary by locality.

Is it your suggestion that we spread the costs across the whole system? Or only across the LMP that's affected by the Demand Response?

MR. SCHISLER: My specific recommendation in my comments was that those details be addressed at the stakeholder processes of the RTOs and ISOs.

However, I do suggest that FERC give guidance that the Cost Allocation mechanism not mandate that the charges get kicked back to the LSE. Because that would undermine what we're trying to do, or what the NOPR attempts to do here.

So it should be broad-based, and that should be the guidance from FERC. But specifically whether you socialize it across the entire footprint--and again sort of charging the transmission customers versus load--those are debates that I guess can happen at the RTO and ISO level.

I guess lastly, before I put it down, the conundrum that I'm having here with this issue is that I do not want to throw up yet another issue that could lead to delay in the issuance of this NOPR. These markets are inefficient, and getting about the business of trying to fix them with full LMP compensation, we should get about that business.

There are details. And there are differences in the RTOs. So we believe the FERC can set the policy guideline on compensation and on Cost Allocation, but the specific details of Cost Allocation can be worked out through the compliance filing process.

MR. HUNTER: Sonny?

MR. POPOWSKY: At least the way I saw it, I think that's the right question, which is which are the zones? Which are the groups of customers or load that would benefit? And whatever those are, those are the ones--whoever gets the benefit of the lower market clearing price, whether that's an entire zone, whether that benefit goes across zones in certain hours, or whether it's RTO-wide in certain hours, that's how you would allocate it.

MR. GOLDENBERG: I was wondering from the RTO perspective, is that something you could do on a practical basis?

(Laughter.)

MR. HUNTER: You're the only one there.

MR. ROBINSON: Yes. I mean, I think Bob Ethier said it this morning in terms of a similar line of questioning. It would be difficult in terms of trying to iterate through different dispatch algorithms to figure out what the benefits are.

So while I suppose we could in some fashion, it would be significantly costly and probably create a whole host of issues around that, as well.

MR. QUINN: Just as a follow up, if you couldn't--if it's going to be difficult to do kind of in real-time or on an hour-by-hour basis, could you at least do something in a compliance filing to say I think they're broader than the local LSE, or they're at about the level of the local LSE, and tell us that for some aggregated period of time, like a year?

MR. ROBINSON: I mean, I guess we could. I guess I'm having difficulty with sort of the fundamental premise. I mean, right now, certainly in the Midwest anyway, the Midwest ISO, we are trying to create LMPs that minimize uplifts in the nature of efficient competitive markets. We have a research underway to, using convex whole methodology, to create a different LMP that will minimize uplift.

So to suggest that we have this action, or this participation that creates additional uplifts sort of goes against the whole philosophy of efficient, competitive markets.

So to me I look at it the same way. I mean, if a baseload unit comes in and drives LMPs down, the market benefits, do we take the differential between what the LMP would have been and what the baseload unit contributed and somehow flow some of that money back to the baseload resource owner? No, that's not the nature of these markets.

MR. QUINN: But we have a different--you have a different problem with Demand Response. Your problem with Demand Response is you don't have the right billing units over which to charge that payment to Demand Response.Ri

MR. ROBINSON: Right.

MR. QUINN: So you have someone you've got to charge that to. And I understand that you want to minimize the amount of uplift. The amount of uplift essentially in this case is fixed. It is the payment to Demand Response. So now it's just a question of who we're going to charge that back to.

MR. ROBINSON: Yes. I think the case that we make is that the appropriate person who should be charged should be the LSE, who has the obligation to serve that load.

MS. SIMLER: Even if there are broader benefits? Because the conversation we had earlier in the morning was about a Net Benefits test. So if you did a Net Benefits test that showed that the benefits were broad to the market, why would you charge it back just to the LSE where the Demand Response was that provided the benefit to the entire market, or to multiple LSE areas?

MR. ROBINSON: To suggest that we need a Net Benefits test suggests that somehow the markets aren't working, and I guess I don't agree necessarily with that.

Or another way to look at it would be, I think Bob Ethier said this this morning, if you think of a Net Benefits test as sort of maximizing the difference between what buyers are willing to pay and what sellers are selling, sort of marginal benefit versus marginal cost, then I guess I'm okay with that kind of test. We could look at that and try to maximize net social welfare.

But to go down this path of uplifts I think it's really creating some bad incentives.

MS. SIMLER: So do you disagree with what Arnie said, that we do have uplift, just as a matter of we've got Demand Response providers that we have to compensate, and the denominator isn't there? So we do have a certain amount of money that we have to allocate, and that's generally what we've called uplift in the past. And now it's just a matter of trying to figure out who has benefitted from the Demand Response, and whether it is only that LSE where the DR came from? Or whether it's broader?

MR. ROBINSON: I think the benefits are broader, but what we're suggesting is that, again, do the counterfactual. If the load didn't drop off, the LSE would be buying from the spot market and paying LMP for it. So they should be charged and solve the "missing money".

MS. SIMLER: Thank you.

MR. HUNTER: Go ahead, Tim.

MR. BRENNAN: I look at the Net Benefits test as really deciding when it's okay to pay LMP, the full LMP versus the LMP Minus G.

So when you're making the full LMP payment, assuming we do, in certain hours, it's still appropriate to try to target the LMP Minus G portion to the host LSE who saw--as I say, realized the load reduction.

Because that host LSE will now have a lower obligation that can resell it into the market, you know, at the LMP price. So when you work through the math, I think ISO New England in their comments put through some examples showing how that works out.

It is appropriate to target the LMP Minus G to the host LSE. Now there are some problems of what is the G. There's some suggestion that in the long term it would be the basic service cost of the distribution company for provider-of-last-resort service, or, you know, maybe there's some way to actually find out what the actual G is for that host utility serving the load reducer.

But there's no question we should try to target the LMP, in my mind, LMP Minus G to the host LSE. Now the remaining money, which would be the G, is appropriate to give and to be spread across all load. Now we can try to target, to the extent we say the benefit was more in one zone to another, we can try to do it to all LSEs in that zone versus all LSEs. I'm not sure that would be worth it. But in any case, it should be spread across all those with load obligations.

Whether those load obligations were served Day-Ahead, or Real-Time, whether Bilateral contracts transferred things, there is an LSE in the market responsible for the load obligation. And we should spread those additional costs for the full LMP across all of those participants.

There's been some suggestions that I think are great if we can do it to put that right in the price, an adder just for that "missing money" in the price. If you don't do that, you can just after the fact say who was serving--who was responsible for all load. Not who had a deviation, but who ultimately needed to serve the load in the hour?

It's just an additional cost to all of those load-serving entities. And there will be no "missing money".

MR. HUNTER: Bill, you had your hand up? I'll call on the Professor here.

PROFESSOR HOGAN: I compulsively whispered to Michael, but let me explain what I'm worried about, and I heard it this morning, too.

Back in the day when PJM first implemented PJM

LMP pricing, they went through a long period of time before it actually became operational, where they were just doing the calculations and showing it to everybody. And for those of us who were there, we remember that in the early days people were sure they were making mistakes; that this couldn't possibly have the--adding generation here couldn't possibly have the effect that it had on these LMP prices all over the place.

And it turned out, no, that's what it is. And one of the reasons I was always an advocate for using LMP for the actual pricing at settlement is because our intuition about these things, when we try to approximate them through all kinds of averages, is just terrible.

We can't even get the sine right half the time about what the direction of the effect is going to be. So if you think you are going to be able to use a single stack analysis, and go walk up and make a couple of adjustments to a couple of prices, and then predict what is actually going to happen to the LMPs around the rest of the system without actually running the but-for case, that'll be a major innovation, let's say.

(Laughter.)

PROFESSOR HOGAN: So I would not assume that this is in any way--I would not build on that foundation of sand of assuming that is easy.

Now doing the but-for calculation then gets you into, do you do all of them in, or all of them out, or one in, or one out, and all these other kinds of usual joint cost allocation problems which are going to be more complicated as well.

So we may have to go that way, but what I'm just saying is do not assume that this is going to be easy. As a matter of fact, if you want to make an assumption, assume it's going to be hard.

MR. HUNTER: Carl?

MR. SILSBEE: Let me come back to the uplift question that Arnie teed up a minute ago. In the approach that I've laid out, I had an example of a 500 kW customer who reduced load down to 100 kW, and the LSE would continue to be responsible for 500 kW in settlement.

Now ignoring the Minus G issues and focusing just on wholesale, that doesn't shrink the wholesale settlement base. It stays with that 500--or it stays with the actual amount of meter spin, or usage. And so you don't create an uplift as a result of doing that.

Now that doesn't mean that we as an LSE necessarily are exposed to paying the LMP that went to the Demand Response provider. We had anticipated perhaps the 500 kW the customer would have used. We may have a tolling agreement. We may have purchased ahead to supply that power.

In any case, you know, we'll supply the power. And we may get for it at LMP ourself, even though it cost us less, so we have some gain to spread back to our remaining customers because of the spot price variation. And to me, it works out without the need for an uplift, and it spreads the LMP not to the LSE but to the market participants who are demanding power in that market, which I think is the appropriate way because those are the customers who ultimately benefit from that energy.

MR. QUINN: In that example, is it fair to say that the reason you don't have an after-the-fact uplift is because that kind of load reconstitution on an up-front basis allocated that cost to you? So the settlement process itself is what is essentially taking the place for Cost Allocation?

MR. SILSBEE: The subtle difference here is it allocated the energy to us. It didn't necessarily charge us LMP because we might have purchased that energy in advance at some price lower than LMP. And then when the market spiked, we were covered but maybe some other market participant wasn't covered and ended up electing to continue to draw power at LMP to serve their customer needs.

MR. QUINN: Thank you.

MR. HUNTER: Any other questions?

MR. GOLDENBERG: I just wanted to clarify one thing. A number of commenters were suggesting that the uplift cost, or whatever you call it, would be added into the Day-Ahead LMP. And I assume by that that that would be the Day-Ahead LMP that would be set by the market for payment to everybody. Is that correct?

MR. BRENNAN: I think one way, and if you look at the CDRI proposal, you charge all load the Day-Ahead price, but the Day-Ahead payments would be the initial clearing price. But by charging all load, you kind of right up front collected what would in the end be shown to be "missing money" if you hadn't done that. And then you use that money that all load Day-Ahead was charged to then pay for instance the host utility who ends up in Real Time because of a load reduction looking to be able to sell back into the Real-Time market. You now have that extra money you collected from the Day-Ahead price applied to load to pay back those Real-Time deviations.

MR. POPOWSKY: That was my understanding of what both NECPUC and CDRI were proposing, basically. And when you say "everybody," all I was trying to say is sometimes everybody in PJM is paying the same price, and sometimes people are paying different prices in different zones. And the impact would be felt in the relevant--and the costs would be spread among load in the relevant market, the affected market.

MR. GOLDENBERG: Well you're not really using it to change the LMP as you would with a generator cost, or anything else. You're not dispatching that unit, or that amount of money, and adding it to the LMP and therefore paying it to everybody, including generators. You're only raising the LMP for load, but you're keeping the LMP for generators at the same level.

MR. POPOWSKY: The idea, as I understand it, would be that you're avoiding a higher--you're avoiding the cost of adding a generating unit. If I had to choose as a customer between paying an LMP here, which included paying some cost to a Demand Response provider instead of having to add a generator when you're on that part of the curve, when every time you add a generator it adds to the market clearing price that then gets paid to everybody, if I had to choose between paying the cost and having that cost spread among all load--that is, paying the Demand Response provider--instead of bringing on another generator at a higher price, and then having to pay all of those costs, yes, the customers would be paying slightly more than they would have been paying if there were no Demand Response provider, but they're paying a lot less than if you had to bring on another generator.

MR. GOLDENBERG: But you're still treating it as purely an uplift cost that's going to be spread across certain number of load, or amount of load. You're not treating it as if it's part of the market. You're just finding that's a way of distributing the cost to a certain number of people, whoever it is.

MR. POPOWSKY: It would be--the idea, at least as I understand it, would be that you spread the costs among all those who benefit by that additional--by the use of the Demand Response. But, yes, that's correct. You're not bringing on another generator.

That's what I said, you're reducing the denominator in effect, which means that the price per megawatt hour is slightly higher.

MR. GOLDENBERG: But you're not treating the Demand Response payment as if it's a generator. If the Demand Response payment was treated as a generator, it would be in the stack and would help set the LMP. And you're not treating it that way. That's my understanding.

MR. POPOWSKY: I'll let Don take that. He's jumping up behind me. You wrote the paper, why don't you say what you meant.

MR. HUNTER: We've got a mike over here.

MR. SIPE:(?) The bid of the Demand Response resources is what sets the LMP. So that sets the LMP, their bid. The uplift that is caused by the mismatched billing unit is restated in the Day-Ahead price. It is in the market in the sense that it is transparent to the load at the time they make their purchase decision, because it is in the Day-Ahead price and there isn't a problem with finality of settlements.

You know what you're buying when you buy it. So it's in the market because it's not an after-the-fact settlement. It is an uplift in the sense that it is part of the cost of the resource that has to be recovered. So the generator bid sets the LMP. You're not taking them out of the bid stack. But that bid will only clear if the cost of the incremental adjustment for the billing unit is lower than the next generator up.

So you see it in the Real-Time market. But aside from that, you don't use it to clear the market; you always know how much DR you're dispatching. As Jamie says, it's a fixed amount so at any point in the stack you know what the incremental adder is. You can show that to load immediately, as they're purchasing in the Day-Ahead market, so that when people are buying they see the correct price, because that's a part of the total cost.

If we can get rid of other uplift this way, we'd like to do that, too. We'd like to have people see it right when they buy it and not be surprised later on.

Thank you.

MR. HUNTER: I guess that was the answer. Megan, go ahead.

MS. WISERSKY: I just wanted--a thought just crossed my mind here when it comes to MG&E and its retail customers. Our retail customers are paying for utility-type Demand Response now. It's predicated on the goals of the State of Wisconsin.

All of a sudden I got this real sick feeling in my stomach that all of a sudden now my customers are going to have to pay for any other retail Demand Response policies of who knows how many other states. And it was just, oh, great, load always pays.

And so granted I know the type of wholesale DR programs that many of you are talking about today are different than say the ones that we have in the State of Wisconsin, but somehow it's like, well, we're paying for ours, and great, now we're going to pay for everyone else's that have different goals, different policies, different regulatory regimes, and I at this point don't know how to reconcile that in my thought processes.

MR. SCHISLER: I was just going to say to Megan's concern that load does always pay. And in this instance, MG&E customers would be asked to pick up some portion that would be allocated to them.

It would only be allocated to them if indeed they are benefitting because there's lower overall cost to serve load. So in that instance, since they are being benefitted by a lower cost to serve load, it's actually in their interest to pay, as Mr. Popowsky said, for some proportion of the means to get that lower overall cost.

At the end of the day, the all-in costs are lower as a result of this strategy, which MG&E customers--retail customers should be pleased to pay for that small benefit that reduced their cost of service.

MS. WISERSKY: May I rebut?

MR. HUNTER: Megan.

(Laughter.)

MS. WISERSKY: I understand the premise and theory that Ken has said, and it's hard to argue against that. But the thing that comes into mind is--now I forgot after that fancy introduction exactly what I was going to say, but the--I would agree with that if you were paying just LMP. But this is a subsidized LMP. And so I would maintain that our customers should not be paying for that subsidy even though you could argue that there are some benefits. I'm just not sure that the costs, or the benefits are outweighing the costs of paying that LMP plus some other form of compensation.

So again, that is what is giving me the unease in my brain.

MR. HUNTER: Would you explain what the "LMP plus some other form of compensation" is? Are you talking about just LMP versus subsidized LMP, and you also mentioned LMP plus something.

MS. WISERSKY: I use a lot of different terms, just like everyone else. I know, it confuses things. Our position, although it's different than those that are around me, is that the Demand Responders should buy the right to sell his or her right into the wholesale market.

MR. HUNTER: So it's LMP plus not having to buy the--

MS. WISERSKY: Right. So in that way--

MR. HUNTER: Okay--

MS. WISERSKY: --because their LMP price is that if they bought the right from me, they are free to resell it in the wholesale market. Then they see the LMP. But if they don't--so in my mind, it's that they're paying something a little more than LMP, and it's that subsidy that I'm concerned that MG&E customers would have to pay.

MR. HUNTER: I'll let Angie--I have a follow-up question. Go ahead, Angie.

MS. BEEHLER: I have to respectfully disagree. We appreciate the power our utilities supply to us, and it's very important to us. But on a side note, when I choose to go to Demand Response and supply that service and that sacrifice to do that, I deliver GHG free curtailment, which is lower than--it's free. It's free curtailment. It's better for the environment.

I also as a customer can deliver value back. I deliver value back in less transition costs. I possibly can avoid peaker costs for customers. I also can provide a lot of value there overall in reducing those costs on a higher level at the wholesale market.

And also have the option and the choice to have different programs that might work for my business better, or in conjunction with your programs. For example, if I do 10-minute reserves, or I installed one-minute metering at Pennsylvania for the opportunity to participate in the Pennsylvania market, the wholesale market there; in Connecticut we installed five-minute meters for that opportunity.

And I think as a result of that, we can provide a lot of benefits to our customers around us, and the IOU's customers by reducing those prices, and those prices trickling down to benefit other customers.

Thank you.

MR. HUNTER: Thank you. I appreciate that.

I guess there's one question to--oh, Commissioner Centolella.

OHIO COMMISSIONER CENTOLELLA: I guess I wanted to respond again to something that Ken said a moment ago. Sorry, Ken, I keep picking on you, but you talked about the consumers enjoy the fact that LMPs would be lower.

I mean, there are some other issues with that, but I think one of the assumptions that is out here is that the only way, you know, that demand is going to respond is somehow if we get it bid into the wholesale market.

And I have a significant concern that we are putting a big weight on one side of the scale here of how Demand Response develops, and ignoring potential others ways in which demand could simply respond to price and develop much more efficiently. I mean, we have got appliance manufacturers out there who tell us, who are working on SmartGrid, that if they could simply see prices they would have their appliances automatically respond to them.

We have controls vendors. We have companies like MicroSoft and Google who are ready to automate people's houses. We have buildings that are being automated to provide regulation in PJM, you know, that don't depend on having an intermediary come in and be subsidized by this extra incentive in order to bid into a wholesale market program.

And I am concerned that we are potentially distorting innovation on the demand side of this market if what we do is selectively say we're going to pay an additional incentive to people who participate in economic RTO programs when that same incentive is not available to consumers who are simply responding to a dynamic retail price.

And I think that ought to be a significant concern in terms of the competitiveness of the U.S. economy and where we are in terms of encouraging innovation in this country going forward. And so I think if we're going to talk about additional incentives, we need to think about how we do this in a more neutral fashion and in a way that will potentially get us further ahead, rather than assuming the only way we're going to do this is by having an aggregator bid that into a wholesale market. Because we may be passing up even more Demand Response benefits by putting a weight on that side of the scale.

MR. HUNTER: Thanks. So I would like to pose a final question I think for--Oh, sure.

CHAIRMAN WELLINGHOFF: Paul, I can't resist.

(Laughter.)

CHAIRMAN WELLINGHOFF: With that speech, I am going to have to jump in here. Angie Beehler over there didn't put in all the technology she put in because of dynamic retail prices. Jay Brew's people didn't put in all the technology they put in because of dynamic retail prices. They put it in because they had the opportunity to bid in wholesale markets.

So again, with all due respect, I believe the complete opposite. I think wholesale markets for Demand Response have in fact fostered technology, and in fact will foster it much faster than the states will, because I have no assurances as to when the states will put in dynamic retail prices with the controversies that are going on, all the political problems with getting those in place.

I think the only way we are going to get this technology in place and we're going to move forward with it is to move forward with it in the wholesale markets.

MR. HUNTER: Commissioner Moeller?

COMMISSIONER MOELLER: And I have the opposite view. I am all with you, Paul. I think without dynamic pricing we have the serious potential of residential consumers subsidizing wholesale consumers, and that worries me greatly. And I think the key is shifting demand, and we've got to do it through dynamic pricing.

If we do this wrong, we will have the opposite effect. So I respectfully disagree with my Chairman.

MR. HUNTER: Anything else?

(Laughter.)

MR. HUNTER: Anything else anyone would like to add on Cost Allocation?

(No response.)

MR. HUNTER: Well with that, any more procedural things that we haven't done?

MR. GOLDENBERG: Just to say it again, I guess, the comments will be put on the record. If you have additional comments you can file them with the Secretary.

COMMISSIONER LaFLEUR: I feel like I should say something. I am not going to weigh in. I am really going to give this a lot more thought, but I think this has been a great session.

When I went back to my office at noon there was an article from one of the, I think it was Public Utilities Quarterly, something like "FERC and the Nutty Professors," something to that effect, but I couldn't disagree more.

(Laughter.)

COMMISSIONER LaFLEUR: I thought the comments were very thought-provoking, and we have a lot to work on here.

MR. HUNTER: All right. Thanks for coming, and with that we are done.

(Whereupon, at 3:22 p.m., Monday, September 13, 2010, the technical conference in the above-entitled matter was adjourned.)

Document Content(s)