STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

14-M-0101 PROCEEDING ON MOTION OF THE COMMISSION IN REGARD TO REFORMING THE ENERGY VISION

TECHNICAL CONFERENCE

Thursday, January 29, 2016
Empire State Plaza Convention Center
Meeting Room #1
Albany, New York

Technical Conference - 14-M-0101 - January 29, 2016

(The conference commenced at 8:59 a.m.)

MS. SCHERER: Okay. Good morning. Is this working?

THE REPORTER: Uh-huh.

MS. SCHERER: First, the important stuff. The Wi-Fi password is state, all low letters, S-T-A-T-E, zero zero one -- state zero zero one.

So I'm LuAnn Scherer. I am not Michael Corso. Sorry to disappoint. I am in the Department's Office of Consumer Services.

I'm going to first make a few remarks and then I'll introduce the panel and the panel can give some -- their -- their opening thoughts.

So as you probably know, the Commission, in its Track 1 order, affirmed that REV markets will result in more efficient system utilization with savings that accrue to all utility customers.

Further, the Commission expressed that -- expressed its interest in ensuring that low income customers benefit from REV. With this in mind, the white paper on rate making utility business models, Staff proposed a two-prong affordability Earnings Impact Mechanism, EIM. The purpose of the proposed affordability EIM is to gauge utility progress towards increasing affordability for low income customers.

First, Staff proposed that utilities be evaluated based on their implementation of a set of programs targeted at supporting low-income customers, use of DER to lower their bills.

Second, Staff proposed the affordability EIM be oriented toward the total amount of terminations and uncollectible expenses.

So the purpose of this panel is to discuss the affordability EIM. With that, I would like to introduce our panel. Yesterday you met Peter Zschokke, Director of Regulatory Strategy for National Grid, Kevin Lang who is partner with Couch White's Energy Group and represents the City of New York in this proceeding, and Marc Webster who is the manager. Marc has several titles. He's the manager of the Retail Access Customer Satisfaction and Appeals for NYSEG and RG&E.

Also on the panel today is Janine Migden-Ostrander. Janine is a -- is with the Regulatory Assistance Project, or RAP, where she advises regulators and advocates on energy efficiency, renewable energy, demand response, distributed generation, and integrated resource planning. Janine has worked in public utility law for many years, most recently as the Ohio Consumers' Counsel where she oversaw the state agency that represents the interests of Ohio's residential households with their investor-owned electric,

natural gas, telephone, and water companies. I also learned today that Janine is a native New Yorker, although she lives in Ohio.

Richard Berkley is the Executive Director of the Public Utility Law Project, or PULP. Richard has a wealth of public interest service and experience in energy and telecommunications law, utility regulation, and legislative and regulatory policy.

Valerie Strauss is the Director of Policy and Regulatory Affairs for the Association for Energy Affordability, or AEA. Valerie directs regulatory and policy activities in support of efficiency and clean distributed generation with a special emphasis on multi-family buildings and low moderate -- low to moderate income communities. Valerie has many years of experience in energy and environmental policy.

So I'd like -- first like each of the panelist to make some -- provide us with their thoughts on the topic and then we'll open it up for questions.

So do you -- do Utilities want to start? I'm not sure if there's one spokesperson or two.

MR. ZSCHOKKE: There's one at this point.

MR. WEBSTER: Right. Unless Peter wants to jump in here.

Good morning. Thank you very much, everybody

being here. I also want to thank the Public Service Commission and the DPS Staff for hosting this forum.

I think we've seen on day one, we had some very good dialogue and -- and really good exchange of ideas and some information brought along. So I'm hoping that day two will bring just as much information.

I would like to speak on behalf of the -- the utilities and I'd like to point that the utilities do have a longstanding commitment and a very proven track record of supporting low-income programs. We have been dealing as we know with affordability in many different forums here, one of which is -- is the current affordability case. And a number of challenges have been identified and we keep these in mind as we move through any of these programs and any -- any of these policies.

Number one, identifying some of the low income customers has been a challenge. They are not always easy to find and, unfortunately, they are a more transient population perhaps than -- than others. So once you've identified them, they may not be in the same place for very long.

We -- we also have met some challenges with respect to whether a customer's low income status can be reported. So we want to keep those ideas in mind as we move forward because they will help to kind of, you know,

circumscribe some of the discussion that we would have later on.

The utilities, as we -- as we have discussed in the past, we don't necessarily recommend an earnings impact mechanism for affordability unless its reward only. And the reason we do that is right now under our service quality mechanisms with our -- in many of our rate settlements, we already address low income and affordability in those cases. So an EIM that would not be reward only could be doubling down on -- on, you know, the current low-income programs that we already have in place.

And finally, the only other point I want to make before I turn it over to the rest of our esteemed panelists is that we do support looking at low-income programs in terms of a DER penetration if we were to do it in, say, a demonstration project. That would allow us the opportunity to maybe test customer interest and evaluate the effectiveness of these programs.

So with that, I will yield to the rest of the group so we can get to the -- some of the Q and A.

MS. SCHERER: Great. Thank you.

MR. WEBSTER: Thank you.

MS. SCHERER: Richard, would you like to --

MR. BERKLEY: Sure, thank you.

MS. SCHERER: -- go next?

MR. BERKLEY: Thanks, Kevin.

So I would also like to thank the -- the audience for turning up today. And I'd like to thank the Commission and Staff for inviting me on casual Friday. It's always nice to come in front of you on a day that I'm actually not wearing a tie and going out on TV so.

This portion of the proceeding, these technical conferences are both extremely important and they're important for a couple reasons. First -- and of course, all of you know there have been a blizzard of proceedings related to REV over the past year and a half. And there are number of reasons for that, one of which at least is that this is an extremely complicated first-time activity.

Another reason is that as Staff and the parties are moving forward to discuss all of the changes that REV is contemplating, there's been a great deal of difficulty in agreeing upon what the thing is that's at the heart of the change. As Alfred Hitchcock used to say what is the MacGuffin.

And so in this case, I'd like to start by observing that we have multiple proceedings going on under the REV banner in the area of affordability, but no standardized idea of what a low-income customer is or should be and no standardized idea of what affordability is.

And so this is a problem that has to be overcome to begin with as a threshold question.

Another threshold question that was asked by one of my staff members a few months ago in a separate proceeding, also under the banner of REV, was why on earth would the Commission consider providing incentives when the actions contemplated could be ordered for free. And I haven't yet heard an answer to that, although I was arguing with one of DPS Staff on the elevator into the wrong building on the way here and got caught up in the argument and almost didn't show up.

So I'd like you to think about those two things as we move forward with this discussion.

So let me then switch to the questions that we were provided. So the first question is what are the advantages and disadvantages of implementing an EIM in this area. And I think the first thing to think about is, depending upon what indices you choose for what is affordability and what needs to be changed to create affordability, an affordability EIM could end up being an incentive to terminate customers, thus lowering uncollected arrears for the utilities. And that is, by any means, a perverse incentive that should be avoided.

So I think obviously that has to be avoided.

Another potential is that by picking an

incentive, if the incentive is set too high -- and I think we all know this sort of intuitively, but if the incentive is too high, the incentive could be a fairly large amount of what the cost of the low-income program in theory would be. And I think I'm stealing Kevin's lines there but he's --

MR. LANG: Great.

MR. BERKELY: -- he's got a better turn on this than I do.

You'd be spending a significant amount of what you might otherwise be using to increase affordability for the low-income customers you're intending to help. And so some reasonable relationship between the size of the incentive and the size of the benefit has to be determined, either -- and of course the Public Utility Law Project would suggest raising the size of the benefit as a good way to keep the incentive at a reasonable relationship to that, but I -- I think others might disagree.

With regard to the next question, which is what is the appropriate incentive to gauge affordability, I would argue first that the question needs to be reformulated a little bit, which is I think the question should be what is an appropriate incentive to drive affordability.

And so while you can create metrics upon which affordability might be based, I think the idea of a metric that gauges affordability seems a little odd to me.

And so therefore, I'm hoping that my colleagues will be able to -- to educate me a little bit about this.

But just to, for the purpose of this discussion today, hypothetically one metric could be a combination of -- of terminations and lowering of arrears, sloping downwards simultaneously as opposed to crossing over in an X, which is one of the things that we're worried about, that terminations would go up as affordability or cost went down.

Another very simple metric could track a decrease in the base commodity cost paid by low income households versus the service territory rate average. And I would suggest that that would need to be regressed all the way down to the census track level, because as we've been doing some research recently on some areas of the state and some of the utilities getting ready for rate cases and whatnot, we've seen that there are districts within a very wealthy section of the state, such as Westchester where the cost of housing has gone up so dramatically that even if the cost of dominant commodity remains relatively -- relatively the same as it had been for the past few years, that the effective impact upon the households would be such that affordability would -- would decrease dramatically.

And I'm not just talking about, you know, Brooklyn, but I'm talking also about Eastern Westchester. So

that's a bit of a problem.

The second thing I think, when we're talking about incentive mechanism, is I think that we have to figure out first what is the genesis of the bad debt because the bad debt that is the eight hundred million plus in sixty days or older arrears is at least part of what's holding down or pressure upon affordability in the state.

And I think an evidentiary hearing into the matter of where that -- where that bad debt came from would be valuable first for us to be able to get at what it's driving on affordability, but second, to be able to come up with reasonable repairs to that problem.

And the last thing with regard to question three above is that we believe that if you are looking at affordability in a census track by census track basis, you have to do something about normalizing the cost of housing because the cost of housing in some parts of the state is obviously more expensive than just about anywhere, but it's also increased at different amounts by different census tracks across the state.

So if you were to examine, for example, the increase in fixed charges and add also the cost of housing, you would look and you would see incredible unaffordability in some parts of the state even where the fixed charges might be going up much faster in other parts of the state, but the

housing cost were not moving up at the same speed.

And so I think -- again, I think we need a very careful granular evidentiary proceeding to tease apart all these things that might be driving unaffordability.

Last, and I think this is very important question which has to do with the penetration of DER into low-income communities. So I think first, there's a presumption embedded in that, that the Staff, the Commission, the parties can come up with a DER delivery process that somehow provides affordability benefits to low-income households rather than simply facilitating and outmigration of funding from the low-income and moderate-income households to cover subsidies to higher-income households. And I think that that's going to be a challenge going forward.

But if you're able to meet that, which is you're able to deploy DERs broadly to low-income households and that there's no outmigration of funds and you could -- obviously, you could probably do that either by incentivizing the utilities to build or contract for long-term supply of low-cost DERs to those communities.

Then I think measuring penetration is -- is relatively simple. Once you figured out the mechanism that you're going to deliver it by, then you can attach metrics to it. But I think the key question there is -- is how do you measure the penetration of benefits?

So assume that you put DER into those communities at the same cost as the utility. Is there any benefit to that? And that, in part, is what the two of the Commission's current proceedings are trying to tease apart in proceedings across the country, which is what is the value of DER.

And for the purposes today obviously a dominant value is affordability, but there's also a question of what else does or do those communities get in the process of getting DER. And let me stop there and we can go to questions later.

MS. SCHERER: Okay. Before I -- before I ask our next speaker, I just want to remind the folks on the phone to put your phones on mute if you are not speaking, please. Thank you.

Kevin Lang.

MR. LANG: Thank you. Good morning. And I'd also like to extend my thanks to the Commission, Commissioner Sayre's here. Thank you very much for listening to this important discussion and to Staff for putting this on. I think it's important, as I mentioned yesterday, that we have a dialogue on these issues and we don't limit the record to just submission of comments. I'll try to be very brief in my introductory comments.

Yesterday, I talked a lot about the value

proposition and concerns about rewarding utilities, if we're going to do that, should be directly related to utility actions and not for actions of third parties.

Slightly different bend as it relates to this issue, I actually agree a lot with what Richard said and with what Marc said. The first three questions that were posed in the notice sort of suggest that there's a decision that's been made that we need this incentive mechanism for affordability. But I don't think that's a correct assumption.

The question is to what benefit would an earnings incentive mechanism provide. And I think that's completely unclear on this record from all of the comments that have been submitted in this proceeding. I don't think there is actually a lot of people that believe it's inappropriate to have such a mechanism. And before we start looking at what that mechanism should be, we need to actually determine whether there should be a mechanism.

Echoing something that Richard said, I understand that recently in an Orange and Rockland rate case they adopted a mechanism to help work on reducing terminations and reducing uncollectibles. We're certainly very supportive of those two efforts, but if you were to apply a similar approach in Con Edison you could be talking about incentive levels in the tens of millions of dollars.

And in Con Edison rate cases, every time we have one, and one I believe is starting today, we fight over what that low-income discount should be, what the overall pot of money for the low-income program should be. And the idea that we would spend perhaps 50 percent of the cost of the low-income program on a shareholder incentive to make rates affordable really kind of defies logic.

And that money, in our view, would much better be used by adding it to the low-income program and directly helping the customers, rather than the shareholders.

So there's a couple of fundamental issues here. We then -- if we're going to look at an incentive mechanism what is it trying solve. As Richard noted and -- and folks that are familiar with the low-income proceeding, there is no agreement amongst Staff, amongst the parties, amongst anyone as to what is affordability.

So if we're being suggested to reward utilities for providing affordable electricity, you don't know what that means. And so you need to figure that out before you start figuring out what the appropriate level of incentive is or what the appropriate incentive is. And I think we're a few steps down the road before we get there.

In terms of DER penetration, I mean, certainly Richard has raised some -- some very valid questions. We think it is very important that DER be

available to all parties, not just to certain segments of the populous. And so we certainly support the idea of DER penetration going up in low-income communities.

How you measure that and how you reward the utilities -- I mean, the whole purpose of REV is to open up markets and not to have the utilities do things but to have third parties do it. So there has to be work by all involved. Does it make sense to reward utilities for actions of third parties. We find that to be very tenuous at best.

And then how do you measure that penetration. I agree with what Richard said. It also has to provide a benefit, what is the value proposition. To have providers come into a low-income community and offer products or services that will actually raise their rates is not something that we're looking for. There are lots of providers out there that can offer benefits and that's what we want to see. That's what could be rewarded provided there's some direct utility action that allows that to occur.

And the only other thing I would note is I think we need to decide the core issues first. The low-income proceeding, there's been comments submitted, there's been conferences and meetings on that. We have the ESCO affordability issue. All of those issues should be coming before this issue.

And I would close by just echoing something

that Marc said, which for the City is an incredibly important issue and that's customer privacy. Who these low-income customers are, they are entitled under state and federal law to certain privacy protections. And when you start saying we're going to single folks out, you then need to start identifying folks.

And we, in the other proceedings, have been very clear that those records are confidential records. And that is not public information. It should not be public information. So that is going to create additional challenges of how you're going to measure these incentives because we're still struggling in the ESCO proceedings and the low-income proceedings with that very issue of identification.

We want to serve these customers. The utilities, kudos to them, they actually have stepped up to help low-income customers. But we have to grapple those threshold issue -- threshold issues first.

Thanks.

MS. SCHERER: Valerie?

MS. STRAUSS: Thank you. I also want to thank everyone for allowing us to participate in this -- in this panel today.

AEA is a mission-driven non-profit organization that provides a full range of building energy

efficiency services including workforce training. And the comments today are my comments, AEA's comments, but I do want to point out that AEA works as part of a coalition, The Energy Efficiency for All coalition, which is a nationwide effort to increase energy efficiency in multi-family affordable buildings.

And so the comments that I'm going to express today also, in general, reflect the -- the perspectives of the EEFA coalition and which has also submitted comments for the record. EEFA includes AEA, Center for Working Families, Enterprise Community Partners, Green Healthy Homes Initiative, PACE, and we act for Environmental Justice.

I think what we've all discovered from our conversation today and yesterday is that developing EIMs is difficult. And it's especially difficult for, I think -- for this particular one. I agree and have as one of my first points to say that we're talking about how we impact low-income customers, but we don't really know what we mean by low income. It was -- it's the subject of much debate and it differs depending on what programs we're discussing.

I would offer the perspective that we do support EIMs. We support an EIM for affordability and for DER penetration, but if we're going to define low income by only those parties that are participants in discount programs under the utilities for the low income-customers, I think

that's insufficient. We've seen in the low-income proceeding that, in fact, those programs leave out a lot of low-income customers. And when you look at the State Energy Plan and other documents, the number of low-income households is much higher.

So we do need to devote some attention to those threshold issues of what is affordability and what is a low-income household, low-income customer.

I would also like to stress -- I think I take a little -- a different approach, not so much on the bill and the rate impact, but looking at where low-income households reside. So taking more of a whole building perspective and many low-income households, I would say probably a majority live in multi-family buildings.

And the point there, as I think Richard pointed out, is it's overall building expenses, it's -- it's the rent payment and the utility payment. Often utility payment is folded into rent or at least part of it is. You may pay electricity, but your heating is part of your rent.

So considering the building stock that these households live in is critically important and increasing the energy efficiency and -- and also facilitating some distributed generation and building energy management systems is vital.

So I think I also want to point out something

that hasn't been mentioned, which is statewide approaches are useful and important and is a baseline, but New York is a very diverse state. And I think it's -- I think in many of these EIMs and, in particular, this one, there is going to have to be consideration of each utility territory's own distinct circumstances, its own distribution system and, in this case, the building stock that serves the low-income customers.

We've recommended a score card for the deployment of energy efficiency measures and perhaps DER more generally in the multi-family housing sector as -- as one instrument of looking at this issue.

We've also suggested a score card metric for tracking installation of DER in environmental justice areas, which are, in fact, you know, defined areas. I also think, sort of, following on -- on Kevin's point, metrics should use participation in programs and bill savings or bill stabilization. They should not be based on utility expenditures, per se. That -- that is not sufficient. What we're looking for is -- is real benefits coming out of this.

And I think with REV, REV's goal is to facilitate markets. And my understanding of EIMs is that they should be used to help in that process. Reward utilities for creating opportunities within the REV construct. So I want to just suggest one example of where it

could be help -- examples that could be helpful. I've also had discussion of advance metering.

And we could envision what would be a good opportunity for utilities and to assist multi-family buildings and their residents is to provide advanced metering functionality up to and into the building itself. It doesn't mean you need to put in an advanced meter in every unit. But by providing that -- that functionality and also working with communities to ensure that there's access to whole building data, you might provide an opportunity for third party providers to come in and work with those building owners and managers to then facilitate management services within the buildings themselves.

So that -- that would be an example, we think, that we would be very helpful.

I think the other -- a couple issues on -- on ratemaking I'd like to -- to also discuss, the white paper, it's related. The white paper raised issues of fixed charges and demand charges. And I don't think we can look at EIMs for affordability in a vacuum. I think we look at it in the context of the larger approach to -- to ratemaking that was raised in the Track Two white paper.

And we are opposed to increased fixed charges. We think they are not only regressive and very, very problematic for lower-income households, but they're

also really antithetical to what REV is trying to accomplish because they provide a disincentive to investments in energy efficiency and distributed generation.

And demand charges are also potentially a problem when communities do not have the ability to manage their energy use. We support advanced metering functionality and we support time variant pricing once there is access to interval data, near real-time, and easily shared, and think that that can be a helpful tool in the longer term for both system efficiency and for increasing affordability.

MS. SCHERER: Thank you.

Janine?

MS. MIGDEN-OSTRANDER: Good morning. I'd like to thank the Commission, also, for inviting me to come and speak. It's always a pleasure to come back to my home state and spend a little time here.

I'm going to be going in a slightly different direction. I'm going to start off by focusing on what I perceive is to be some of the problems, why earnings incentive mechanism measurements are important, and then talk about some of the programs and other things.

So the question has been raised about whether or not there should be an earnings impact mechanism. And I'm going to take the position that I think there should be. And part of the reason for that is that the low-income community

is a very large community. They pay approximately 5 to 10 percent of their income for energy, which is a huge energy burden compared with the rest of the residential population, which pays about 1 to 5 percent.

And so if you don't -- when you're -- when you're establishing what areas or what issues are you going to create earnings impact mechanisms, if you don't include low-income issues and affordability, it's saying that that isn't a top tier issue. And this is a top tier issue and so I think it should be included.

And the key question is going to be how -- what kind of metrics do you put together. And I will address that in a moment, as well. I spent the last couple of days reading the Staff report and trying to get up to speed on what's going on in New York. And I think one of the things that really struck me was the lack of uniformity around the state in terms of policies for extended payment plans and other kinds of re-connection fees, disconnections, availability of assistance, and so an act of geography means that one customer will have more services and opportunities available to help them than others.

And so I -- my first recommendation would be to create a statewide minimum threshold that all utilities must meet and of course utilities are always welcome to go well above and beyond. And we have that in place -- I've

seen that in place in a number of other states.

So some of the issues that I do want to focus on is there's -- there seems to be a lot of question about, you know, funds available to customers and how big is the pot and how do you divide it and how do you determine eligibility.

A lot of the eligibility for low-income customers for -- and I'm going to talk about Ohio because I was the Ohio consumers counsel for eight years and I know that example very well, and there are lot of examples that are similar to Ohio that could be used, as well.

We used the eligibility for -- for LIHEAP and HWAP worked very closely with the community action agencies to sign up customers. So when a customer comes in to a local community action agency for food stamps, they're also made aware of what's available on the energy side. So that might be one way to try to capture the low-income customers, one way to kind of address the privacy issues because they're there, they're in the door anyway.

And the utilities pay a small fee to the community action agencies to help them administer the HEAP payments, the HWAP payments. And what we do with energy efficiency is with our energy efficiency programs, we have settlements with utility companies to allocate one-third of the residential pot to low-income customers to enhance and

build upon the existing weatherization to get services into the homes.

And this can also -- and that doesn't mean that because you're getting -- your low-income customer getting assistance through this program, which again also is administered through the same agencies that are doing the HWAP. So it's sort of a one-stop shopping.

You -- if the utility has a CFL light bulb program, any customer can get that including low-income. So low-income has access to all programs plus one-third dedicated for that.

In terms of things like how do you -- how do you help low-income customers -- and I noted this in the comments of some of the folks that filed. They made reference to Ohio's percentage of income payment plan. And under that plan customers pay 6 percent of their income for their electric bill, 6 percent of their income towards their gas heating bill. If they don't have gas heating and they're all electric, they pay 10 percent.

And the remainder is put into an account that they have to eventually pay back. But we have a very -- a very good debt forgiveness program in place that goes along with it. The rest -- the lost -- the parts of the payments of the customers that the utility does not recover from the customers gets put into a surcharge. It's a separate PIPP

rider, separate from the uncollectible accounts and gets reconciled every month and is on customers' bills.

I can tell you it's sizeable amount, but it's keeping a lot of people connected and helping a lot of people have affordable service.

Another observation I wanted to make, which is also something that could help low-income customers, is the authorized agent issue. A lot of low-income -- in a lot of communities, utilities have shut their offices and there are authorized agents, but you have to pay to use an authorized agent. So think about this. You -- in your home, you -- you do an automatic bank transfer, you write a check, you pay by a credit card.

But somebody who doesn't have a bank account, doesn't have a credit card, they have to take -- maybe take a bus across town if there isn't an authorized agent nearby or if they're lucky maybe there's one in their neighborhood and then they have to pay 5 dollars -- 8 dollars, whatever the fee is, in order to pay their bill. This is for people who -- for whom their energy bills already represent 5 to 10 percent of their disposable income.

So one -- one policy to consider is waiver of that fee and for the utility to pay the authorized agents. And at any -- in any event, authorized agents benefit from having the service because if you go into their store to pay

a bill, you're probably going to pick up your -- you're probably going to buy your milk there while you're there anyway. So they -- they get extra business.

And it's these kinds of things that really impact affordability. So what are some of the things that can be -- yeah, there was one other thing I wanted to talk about, extended payment plans -- creating a uniform statewide minimum extended payment plan.

What we have in Ohio is that customers have to pay if they're in trouble, they can't pay their bill, they have to pay their -- they call the utility -- our office used to have a call center that would help them. They could pay their current bill plus one-sixth of the arrear and avoid disconnection, and you could negotiate with the utility 9 months. And we did that a lot.

If, you know, the customer said I can't make that one-sixth but I could make -- make it in 9 payments then -- and the utilities, rather than lose the customer and lose the revenues and disconnect, were usually pretty good at working with our office in terms of allowing customers more generous extended payment plans.

But that's the way you're going to avoid disconnections and that's the way you're going to help customers continue to have service.

So what are some of the things to measure?

If you're going to do some kind of a measurement and have some sort of earnings impact measurement -- and again, it could be a modest one. I mean, because the points being made about how money should be focused on helping the customers is a very valid one. But take -- create a baseline and then look at such things as number of disconnections. Are they going up or are they going down?

I don't know if, in New York, you require utilities to provide data to the Commission on how many customers are 30, 60, or 90 days in arrearage, but measure that. Are those numbers going down?

Number of customers who the utility has negotiated with to put them on extended payment plans, as opposed to being disconnected. Are they being -- you know, are they being more agile about that and increasing the numbers? Number of days to address consumer complaints, what is -- what is the timeframe? You know, that's a big issue for customers, especially when disconnection is looming above them.

The number of authorized agents and where they're located, are they located in the communities where the low-income customers reside so that they can have easy access to them?

Incentives for removing the fees for paying an authorized agent. Progress on low-income assistance

programs, how they are making those programs available, how they're educating, what is their outreach, how many more customers do they have on these programs.

A number of low-income customers targeted for energy efficiency programs. What are they doing within their energy efficiency budgets to specifically reach out to the low-income community and help them and working with community action agencies to leverage weatherization dollars so you get a much bigger bang for your buck and you can do more -- much more holistic assistance.

And then the number of low-income customers that are targeted for distributed generation. Community solar projects that are being helped through any number of these other kinds of projects that are starting out in New York. How much is being focused on the low-income? What do we -- what resources are you making available?

So those are some of the measures that you could use to determine whether or not a utility is entitled to some kind of incentive. And the incentive mechanism can be set in accordance with what's reasonable.

Thank you.

MR. LANG: I just feel a need to respond to a couple of things that were just said. LIHEAP may work in Ohio; it does not work in New York City. The vast majority of low-income customers in New York City do not get HEAP.

And if we were going to rely on HEAP, we are going to miss the vast majority of low-income customers in New York City.

So what works in other states may not work here in New York. And we have a -- a very big record on that issue in the low-income proceeding and we would strongly urge against just focusing on the HEAP payments to measure low-income.

Also I know this is the case downstate, I'll defer to the gentleman to my left, but there are authorized agents throughout New York City, none of which charge a fee.

There are other types of providers that also collect payments that may, but when Con Edison closed its service centers a number of years ago that was a condition imposed by the Commission. And to my knowledge, they are still continuing with dozens, if not hundreds of authorized agents that charge no fee for payment of bills. So we have that issue and --.

MS. SCHERER: So Kevin, can I just ask a question? So in that case, the utility is paying the fee?

MR. LANG: They've negotiated it with these various providers is my understanding, but customers can go in and just pay their bills. There's stores, there's other places --.

MS. SCHERER: I think that differs from other areas of the state.

MR. LANG: And the other thing I just wanted to note is on some of the measures that were just mentioned, they are already part of customer service performance mechanisms. And right now, they work in the opposite direction because we want utilities to maintain certain levels of service to these customers. And I'm not aware of any reason why we're going to take measures that have been in place for years and years and years that have worked very well, and turn them from the way they're structured today to now positive incentive -- positive incentives. There's nothing that establishes we need to do that for many of those measures.

MS. MIGDEN-OSTRANDER: If I could respond?

MS. SCHERER: Go --.

MS. MIGDEN-OSTRANDER: Okay. On the LIHEAP, that probably would work in rural areas, more upstate New York parts of the state. And that was not a mutually exclusive suggestion. That was just a suggestion of something that has worked in some places.

Obviously, where you have large multi-family housing, there are other things that you can -- can use. If there are community action agencies or places where they're going to get food stamps, for example, that would be one way to help locate that -- that community.

So as -- and as to the authorized agents,

that's great. So that should be -- that should be the bar that should be set for the rest of the state so that you do have -- so customers aren't paying those fees. So I thank you for that information. That's really good.

And then customer service mechanisms, I think this -- this is a list of potential mechanisms if you have some of them in place. But if you set a baseline and you say if you perform above and beyond this and you try to raise the bar, that's the whole idea of an -- of an incentive mechanism is to try to raise the bar above. And if it's working fine, then -- then maybe that's not the right measurements. These are just suggestions that are not -- you know, that are to be considered based upon the facts.

MR. LANG: But you also have to look at cost effectiveness. And, you know, if you set thresholds and say to the utilities now go out and exceed them, there is a cost to that. And right now, it has not been demonstrated for a lot of those that the benefits will exceed the cost of exceeding the thresholds that are already in place.

MS. SCHERER: Anybody else want to respond?

MS. MIGDEN-OSTRANDER: It's a fair point to -- to measure, for sure.

MR. ZSCHOKKE: Certainly, in -- in Massachusetts in particular, we have a number of different aid programs for which people are eligible for the low-income

rate and low-income programs. But we also recognize you won't get everybody. Not everybody is in an aid program and it is an issue that if you try to target low-income, it will always be tough because how do you identify them and -- and -- and what you say to them when they're not in an aid program because you do have to -- you do have to respect their privacy. So getting them to come forward is obviously very difficult.

I would -- I would say there's a couple of things that -- what Janine and Kevin were discussing comes to my mind. I think one of the things is what is the flexibility that utilities have to actually innovate and change. I mean, there are rules, regulations, and laws about what we can do with customers when it comes to an issue of credit mechanisms, having an issue paying their bill. And there are things -- procedures we have to follow. And the question is what level of innovation could we use to see if we can improve customers' capability.

Valerie mentioned advanced metering functionality, which I have always believed -- I've actually had conversations with low-income people when we talked about a smart grid pilot in Worcester. You know, low-income customers have a disadvantage. They -- they go -- move into a place they're unfamiliar with, they're very transient, and then a month later they get a bill from the electric company

and they didn't realize it was going to be so expensive, right, because they don't have any idea what's going on.

If you're talking about -- I'm glad Valerie mentioned it, but I've always thought that that would be a value to the metering data to have customers aware of how much they're spending in real time, instead of getting a bill they can't afford after the fact. Because they're unfamiliar with the apartment, they're unfamiliar what are the cost are.

So I think that's important. That type of ability to innovate by giving customers more information would be -- would be important in this area. Now it doesn't necessarily have to be advanced metering functionality. We could discuss -- and I'm not here advocating it, so please don't. I know there's passions on both sides so please don't. This is not about this issue. It's about affordability. You know, it's about innovation.

But pre-paid metering, which I remember talking to one of the British distribution companies back in the early aughts. And they -- when they had an issue with the credit customer, they put them on pre-paid metering. And then after a few years they had 400,000 thousand customers on the pre-paid metering and their cash flows were positive, not negative. So they were getting the money before they were spending it.

So I'm not saying we should do it wholescale

but, you know, that would be something that a utility could try. Because I am concerned about things like pre-paid metering, how do you get through a winter in Buffalo when you're doing pre-paid metering. You do not want people to go without electricity and to -- to put themselves at risk. And we need to really monitor it, but we could try it and see if it works and if we can make it comfortable for the advocates or not.

That's the thing we have to think about. What are the levers? We're going to have an EIM, what are the levers you're going to use to help customers improve their capability of paying the bill and then improve the ability of the utility to serve them, going forward. So they're -- the bill is affordable for them and the utility can take care of the problem for the customers as necessary.

I do want to mention as we talk about affordability, we also have to think about the other elements. REV and a lot of the public policy that's coming forward in the state is bringing new value equations for customers. You know, we want to have cleaner energy. We want to have cleaner resources. That's a different value stream than we have traditionally thought of, which is, you know, low cost to customers, which we still want, but it may be more expensive to provide clean energy to customers than it is to provide the traditional sources of -- of energy.

And we do have to be considerate that when we talk about these EIMs that the impact of policies on customers' bills will -- possibly could result in a contradictory effect than what we're trying to do with an EIM that's targeting -- that's targeting shut-offs or targeting the amount of bad debt. Because if the bills go up because we're paying to fund something that we think is necessary for the state and is good for the state because it's a new value stream for clean energy, then we have to recognize that that's going to have an impact on this. Any EIM we create to do this is going to have an impact on customers.

MS. SCHERER: Go ahead.

MS. STRAUSS: I just want to add one or two thoughts to that.

I think we do need to be cognizant of the fact that -- that changes under REV will impact bills. Obviously, the goal is to stabilize -- stabilize bills. And I am saying bills quite deliberately not rates because I think there is a difference. And we like to focus on bills, not rates.

But I'd also like to suggest that, in talking about managing cost of housing and utilities together, that I realize in parts of New York, particularly rural upstate areas, low-income households may live in single-family homes, they may own their home, but a vast majority of lower-income

customers do live in -- in urban areas and in multi-family housing and, on average, energy expenses in multi-family housings are about -- average about 30 percent of operating expenses, which is a pretty hefty chunk of change, particularly if you're a building owner or property manager that has a number of large properties.

And in places like New York City, which -- where there is rent stabilization, you find landlords or building managers coming in and arguing for rent increases because their utility bills have gone up. So I think having a whole building energy efficiency approach can help offset some of the -- the issues, potentially increased bills and also address the issue of affordability.

MS. SCHERER: Valerie, can you expand on the score card concept that you mentioned and can it be adapted to single-family homes?

MS. STRAUSS: Sure. I think it can, to some extent. We -- we did suggest in our comments, the EEFA comments, that there be a score card for multi-family building sector. Obviously, that's more appropriate in certain places than others.

I think we also suggested a score card for environmental justice areas. And that, in many regions of the state, includes areas with large numbers of single-family homes and -- and it includes, you know, Indian reservations,

et cetera.

So I think looking at environmental justice area or census track type of an approach like Richard mentioned might be one way of addressing that.

MS. SCHERER: We talked a little bit about the incentive mechanism related to terminations and uncollectible. A number of parties commented that there would need to be a -- there may need to be a mechanism for normalizing economic indicators. Do anybody have thoughts -- does anybody have thoughts on that?

MR. ZSCHOKKE: Well, the economy does affect the number of customers that are in a bad situation. And so -- so how you would do that, I don't know, but I'm sure people could come up with ways to do that. But there will still be statistical variance around that that will make things less accurate than if you can just count numbers.

So if you did have one, yes, you would need to take -- you know, one of our concerns is all of the external influences to affordability of customers, you know, it's not just the overall health of the economy, but it's also how much is the southern part of the country taking away in manufacturing from Upstate New York or -- or China is taking away. I mean it's more than simply is the economy healthy of the state. It's the economy of the regions of the state -- the state as well. So -- and that's going to be a

tough one to really figure out.

MR. LANG: I would just add, I mean, I certainly agree with Peter that how you would do that I don't have a clue. It's another example of why an earnings incentive mechanism here is even more problematic because there is the potential to significantly over-reward the utility, or conversely, potentially if we're going to go down an incentive route, while we don't agree with it, you could be under-rewarding them too because of changes in the economy.

Again, we believe that these mechanisms should be geared specifically and solely to actions taken by the utilities, not all of these extraneous influences that are equally as important.

I mean, I would just echo what Valerie was saying is this is probably an area that is more right for score cards than incentive mechanisms, that you can start to measure some of these things. Janine had a list. There's absolutely things on that list that make a lot of sense. But to me, they make a lot more sense, at least for now with all the uncertainty that's out there, that they're score card items. Let's start monitoring them. Let's start tracking them. Let's see how performance is changing over time.

And then if we identify a problem or we identify an opportunity to maybe create incentives, do it

based on the factual record as opposed to assumptions and guesstimates.

MS. SCHERER: Anybody else?

MR. ZSCHOKKE: I think the utilities would agree with the score card. I mean, when you think about innovation, you -- you track the information that you think is interesting and then you see -- you encourage the utilities to put forward, you know, innovative proposals like try out pre-paid metering, knowing all the concerns people have, to see if you can overcome those concerns or try out advanced metering functionality and how you can do budgeting for low-income customers.

And, you know, don't do it to everybody, do it to some, and see how it works. And then -- then you put something in to say, okay, make it work more effectively now that you know what the cost to do those things are and you know what the benefits are. And then you can create innovation for which you may then want to move from the score card to an EIM.

But still, you know, you'd have information from which to move forward. And you'd create an -- an environment in which innovation in this area would be welcome.

MS. SCHERER: Anybody else on the panel?

Should we turn over questions to folks on the

phone?

Does anybody on the phone have questions for the panel?

How about anybody in the audience? Questions for the panel?

MR. LEONARD: Pardon me if I'm a little bit feisty this early in the morning, but --.

UNIDENTIFIED SPEAKER: Can you state your name, please?

MR. LEONARD: Ron Leonard.

So two things I want to -- to bring out, which you've sort of discussed a little bit. One is perception and one is big data. And to -- to try to make it a little bit light in terms of perception, I'd like to discuss a fictitious utility called Eddie's Utility and a fictitious C.E.O. called Crazy Eddie. And Crazy Eddie makes probably 5 million, 6 million dollars a year, you know, normal big buck C.E.O. salary.

And then you look at perception-wise how much that Eddie's Utility spends on monthly, say, subsidizing poor people. It doesn't look very good when you look at things that way.

Secondarily, looking at proceedings that Central Hudson had in their area with the PSC and cut-offs and a lot of egregious complaints were put against Central

Hudson's proceedings. And I don't think we should focus in on Central Hudson as a bad example or player, but in general the perception is that utilities really are not handling this process well and that consumers are not really being protected in a way that is fair in the marketplace.

So the second part of this discussion that I'd like to see happen is how does big data play into this. And you brought up smart meters, but I don't really think we have time for smart meters. It's just way too far down the road to look at as a solution.

But big data is a solution today. My friend Frank over here can tell you about a company that will be able to take a look at a building and, having the electric bills, find out if that building is doing the right thing.

So for example, if you look at New York City, New York City has lidar data of every single building in the city. You can talk -- look at a multi-family building, figure out what the utility bills are, both gas and electric, and figure out if that building is making sense.

And, you know, I grew up in New York City. I've walked into these apartment buildings and seen the window open and you say, it's the middle of winter, it's minus 10 degrees out, why is the window open? Because we can't turn the heat down. That is an unfair process.

So in terms of the big data picture, we can

really ameliorate some of the problems that we have right now, almost immediately. When you have a poor family, elderly family, upstate New York, who can't afford to heat their building because they have single pane windows on it. And it's leaking heat like a sieve. If you have a multi-family housing that's using a ton of electricity because they have old Edison light bulbs in there, this is something we can fix now.

And we don't have to worry about how can we identify poor people. We can identify poor people when we find out their electricity is being cut off. Start there. Have a baseline. Fix problems. Let's be proactive in this process, rather than just discussing logistics and possible means of forcing utilities to act in a little bit more of a preemptive way.

MS. SCHERER: Thank you.

MR. FLINT: Good morning. Adam Flint, New York Energy Democracy Alliance.

I'm glad I came after you because that -- maybe I'll be nicer, but maybe I won't be. I think -- I hope one thing we can agree on is that the current system is completely inadequate. We had a quarter of a million shutoffs last year. Not acceptable. Okay. So that to me is the baseline.

I also agree in what the last gentleman said

in terms of the timescale. I think there are things that REV can do at different stages, but there are things that need to be done now and I think some of those things, we know what they are.

I would also agree, though, that it's not fair for anybody, much less the utilities, to be penalized or rewarded, and I do mean penalized because in some of the discussions yesterday we talked about symmetry in EIMs and I think there needs to be both teeth and reward, whether it's an EIM or not in terms of this question.

For utilities or anyone to be held responsible for things that they simply can't control, I mean, that seems sort of unfair. But utilities do have a large responsibility and they do have things that they can't do.

One part that seems not sufficiently emphasized yesterday and today inasmuch as it's been discussed or is a topic for today is the role of maybe going a bit further with what was said by Valerie and -- I'm sorry, I've forgotten your name.

MS. MIGDEN-OSTRANDER: Janine.

MR. FLINT: Yeah. I think, from my own experience working upstate on Green Jobs Green New York, now on solar moving into shared solar, you are going to have to have a very robust energy education boots-on-the-ground

operation, A. You are going to want to partner with obvious and relevant agencies, B. And three, someone's going to have to pay for all this. And it can't be the low-income customers. You can't just roll it into the rate. That's -- that's not probably a good idea.

Where we get the money, how we do that, there's different discussions about where that can come from.

So just one concrete suggestion I would make is that there is REV demonstration projects going on right now. There's a lot of excitement about shared solar in general and as a solution to low-income equity and access to DER right now. Yet, upstate where incentives are entirely too low for large arrays already and the market's pretty well dead, it's not a place that private developers have much of an incentive to go. And we've heard this directly from them.

So what I would strongly suggest is not just the utilities, but the parties at the table as regards this, NYSERDA, yes, the utilities, the Commission, and those of us who are in the field doing this work, private developers, non-profit organizations, have some demo projects set up this year, early.

That means there's going to need to be some operating capital and it means that NYSERDA's going to need to make some good decisions about incentives.

So I'll -- I'll leave it at that. And thank

you very much for bringing this into the discussion.

MS. SCHERER: Thank you.

Does anybody want to respond to that?

MS. MIGDEN-OSTRANDER: I guess I want to understand more. I have a follow-up question to you, which is --.

MR. FLINT: I'll come back.

MS. MIGDEN-OSTRANDER: Thank you. Why is it that the solar market is not thriving or is nearly dead in Upstate New York?

MR. FLINT: I should clarify. It's the above 200kW solar market that is not --

MS. MIGDEN-OSTRANDER: Okay.

MR. FLINT: -- thriving upstate. And the reason for that is somewhat complex on one level, but simply put, the value of solar since the ruling by the Commission combined with inadequate incentives by NYSERDA over the last year essentially reduced the value of large solar by 60 to 70 percent over what it was before.

To be fair, monetary net metering was a bit of a game situation. We all get that. But the long story short is Upstate has not done well since the grandfathered projects at all. So that's the situation there.

MR. ZSCHOKKE: Maybe all the units in our queue are prior to whatever the orders are, but we have a

pretty busy queue, from what I understand, for large -- larger projects for Upstate New York.

MR. FLINT: There's a huge backlog of grandfathered projects.

MR. ZSCHOKKE: Yeah.

MR. FLINT: And in fact, the utilities were sitting in this room today when they were talking about interconnection, saying well, don't beat us up too bad about this horrible backlog because you guys made a decision that threw the market into a tizzy because everybody was told get your project in now or not happening, so.

MR. ZSCHOKKE: Right.

MR. FLINT: There is -- I -- I guess, I'll add another thing. There is a vast and vast and vast and I think sometimes not fully understood by everybody difference between upstate and downstate in a lot of ways and within regions. And I think that's an important thing to consider, as well.

So when designing whatever comes out of this, I would go back to your comments and others that it needs to be sensitive to the situation in the different utility areas, as well as sensitive to the situations of low-income people in the different utility areas.

MS. SCHERER: Thank you. Thank you. Anybody else?

MR. ZSCHOKKE: So just to be clear, I know we have a few hundred megawatts this year that, you know, we're expecting to come online. There may be a future where nothing's -- nothing is in the queue but there's a lot of work to be done right now for that, so.

MR. FLINT: I should say that NYSEIA's been pounding the door the last year on this one and they're not going to go away, so.

MS. SCHERER: Anybody else in the audience have comments?

MR. O'BRIAN: Good morning. My name is David O'Brian with Navigant Consulting.

I had to come up and talk a little bit about pre-pay because Peter mentioned it. I have to tell you I've read a lot about pre-pay programs. I would strongly encourage Staff and folks to look at the Salt River Project has done that a lot with this and been very, very successful. And they've lowered disconnects and not -- uncollectibles from low-income populations dramatically.

And it's actually for a very simple reason. And I would counter or have a different opinion about the value of AMI in this case because it's a classic information is power sort of circumstance where you're talking about giving people the information about their energy consumption in much more granular detail, 15-minute intervals, instead of

30 days later after, you know, post the month.

And so you can imagine an environment where the customer says this is my budget that I want to spend on energy for the month. Say, it's 50 dollars, if that's the number. And then they have the feedback mechanism on a daily basis of where they stand in terms of how much energy they're consuming and where their bill is headed before they get to the end of the month. So they can avoid the very issue that we're -- we're trying to avoid here on a larger sense.

And so I think there's a lot that can be done with technology and with a more intelligent grid and the sort of tools that you can imagine as talked about in REV that can really be brought to bear for this population. Because I think there's a lot -- lot of positive that can be done.

But I think you have to think about these incentives or earning impact mechanisms, perhaps the score card as Kevin alluded, but certainly it's a positive only incentive to really put something out there for the utilities to create those -- that environment and to offer those tools to the -- to this population.

MR. LANG: Okay. Excuse me, can I just ask you that --

MS. SCHERER: Okay. Go ahead.

MR. LANG: -- if this customer with a 50-dollar budget, it gets much colder and they exhaust the

budget on the 10th day of the month --

MS. SCHERER: That's what I was thinking.

MR. LANG: -- what did they do for the other 20 days of the month? Do they just not have electricity? Because that's just not acceptable.

MR. O'BRIAN: No, I'm not suggesting that. I'm saying that I don't -- I'm not saying this solves the entire problem and it eradicates, you know, whether it's a very cold month and they've run up their bill to a certain point. But it gives them the ability to identify that the problem exists much sooner and potentially do something about it, whether that's the utility or some third party engaging with them sooner, an agency, what have you.

But the point is that they can be much more aware or cognizant of where their usage is going and what their bill is going to be before they get to the end of the month before it becomes too late.

MR. LANG: I understand. I mean, in concept maybe it's something that could be looked at, but I see a whole host of very significant concerns in the state that we would need to work through before we ever install these pre-paid meters.

MR. ZSCHOKKE: And that's -- that's why I suggested that we do -- we try something out because we don't want customers taking 20 days without electricity in the

middle of January in Buffalo. And so, but -- you know, how it will work, I mean put some out there and see -- you know, don't put the customers on the rate, but put some out there and see what they learn, see what they do, and see, you know, just innovate to try to figure it out.

MS. STRAUSS: I would -- I think there are all kinds of billing arrangements that could be useful, time variant pricing being one of them.

Pre-pay has a host of concerns, I think, for low-income advocates. I'm not -- not to say it can't ever be useful, but as Kevin's alluding to, I would strongly caution against implementing something along those lines without a lot of data, real-time information, not simply oh, gee, you're about to run out of money. And -- and also with a strong energy efficiency and weatherization program that goes hand in hand with that because I think we've seen -- as we've seen in -- in New York City, it's not -- it's comfort and it's also safety. People have their gas shut off so they -- you know, they have their electricity shut off so they turn on their gas stove for heat and we have fires.

So I think you have to be very careful, particularly in the intersection between the heating and the electric usage. There are comfort and safety issues, as well. Just for example, where you also -- as an aside, sometimes you have a weatherization program or a great deal

of energy efficiency work done and you find that usage doesn't go down. And that's not because it's not much more efficient. It's because those families that were living in very cold circumstances and wearing jackets in the house said, you know what, I can afford to turn my heat up. So I think we have to be very careful about how we measure and -- and what kind of safety and security we provide to these families.

MS. MIGDEN-OSTRANDER: And I -- I would add also I agree with what Valerie and Kevin said. One of the big concerns with regard -- you know, pre-paid metering should be -- if it's going to be implemented, it should be piloted and it should have a host of consumer protections in it. I think one of the big concerns is if, at the end of 30 days, if you're on -- on a regular metering and you don't have the money to pay your entire bill, you don't get disconnected right away. You're given a sort of -- with the disconnect notices and others, you're given an opportunity to come up with the money so that you can keep service flowing.

Pre-paid meter, the money runs out. You need to have some sort of mechanism in place that even when the money runs out of the meter, customers still have the same disconnect notice windows and opportunities to maintain service.

And another issue is also utilities charge a

late payment fee if you're late. Here you're pre-paying, so should there be a premium on the rate, a discount to customers because they're pre-paying and the utility has the use of their cash? So it's creating somewhat of a symmetry here. You know, if you're going to -- if you're going to charge late payments, you should charge a pre -- you should give a credit for a pre-payment.

And then there's a whole host of other issues. It's not to say that they can't be worked through and tried out on a pilot basis, but we have to be very careful that we don't have customers in the middle of the winter or the middle -- or in a hot summer getting sunstroke because their meter ran out.

MR. O'BRIAN: Yeah. So -- so let me be very clear. I knew I was actually stepping in it when I came up and -- I do that, you know, knowing, you know, my free will I guess.

So I'm not suggesting, by any means, any of the sort of very, you know, awful circumstances you're describing. What I'm suggesting is is that if you think about what the technology can do and what the structure of a pre-pay program presents, you're doing something that is additive or incremental of what we're doing today, which is really more reactive to the problem than proactive.

That's really what I'm suggesting. And I

think Peter's observation about doing this on a test basis, absolutely. I would not make -- I'm not sitting here saying let's jump to a circumstance or repay -- pre-pays especially with the reservations that I just heard.

But I think putting these customers and more and more customers into a position of knowledge of where they stand on their consumption and have the tools to respond, whether that's, for example, dynamic pricing that they, you know, have automated devices that, you know, manage some of their things in their home and save them money. Those all things are positive and I would -- I would just suggest that just because it's a low-income population doesn't mean those things aren't possible.

And I would definitely suggest we take a look at -- there's a lot of studies out there I can point to that show what a dramatic difference happens when people have that information in a proactive way, what happens to their energy efficiency. And that's all I'm suggesting.

MS. SCHERER: Can I add one more thing?

MS. MIGDEN-OSTRANDER: Can I ask a question, please?

MR. O'BRIAN: Uh-oh, I'm not supposed to be on the panel, so.

MS. SCHERER: We --

UNIDENTIFIED SPEAKER: It's time to move off

of pre-pay.

MS. SCHERER: -- clearly there's a lot of concerns, not the least of which is Public Service Law, but that's for the lawyers to figure out.

But I have a question with regard to the Salt River project. I'm not sure where it is and I'm just wondering if you know how they deal with fixed charges. We have pretty significant fixed charges here and it could be that a customer who wants to allot 50 dollars uses 40 percent of their 50 dollars in the first day of the billing cycle. So how do they deal with that?

MR. O'BRIAN: You know, I don't -- I don't know what the fixed charges are in that specific program. Maybe Peter does.

MR. ZSCHOKKE: If I -- if I may? Well, they have fixed charges for regular service. They now have a little bit of an issue. Salt River project is in Utah; right?

MS. SCHERER: That makes sense.

UNIDENTIFIED SPEAKER: Arizona.

MR. ZSCHOKKE: Arizona. Okay.

MR. O'BRIAN: Arizona.

MR. ZSCHOKKE: It's not a muni; it's a cooperative.

MR. O'BRIAN: No; it's actually a government.

UNIDENTIFIED SPEAKER: Supreme Court doesn't know what it is.

MR. ZSCHOKKE: Okay. So it's not an IOU Let's put it that way.

But they -- they had just recently issued an order that for people who put solar on their roof they have to pay 50 dollars a month customer charge which I believe they've been taken to court for -- for such action by some of the solar vendors.

So that's -- they raised the customer charge for those who have solar and not for those who don't have solar. I don't know what their regular customer charges are.

MR. O'BRIAN: Right. I don't -- I'm not familiar. I can take a look at it.

MS. SCHERER: That's fine. Thank you very much. We -- only have a couple minutes left, so sir?

MR. BERKLEY: One second, LuAnn.

MS. SCHERER: Yeah.

MR. BERKLEY: I just like to say that while this conversation has been interesting from an academic standpoint, it had -- it had nothing to do about affordability. Smart meters, time-of-use pricing, they cost money. They don't save money.

New York State would roll out 6 -- 7 -- 8 billion dollars' worth of smart meters, I defy anyone to show

me how that's going to reduce rates. So while it was interesting to learn these things, not germane to our discussion today.

MS. SCHERER: But yet, AEA raised it in their comments.

MS. STRAUSS: I would also say we think their advanced metering functionality actually could help bill management, which they were more interested in overall bills. So we have a little bit of difference of opinion.

MS. SCHERER: Sir?

MR. WAGGONER: Danny Waggoner of Advanced Energy Economy Institute.

One really quick point about the smart meter is such a good report that shows the amount of savings you can get and demand reduction and how that relates to lowering CapEx. And the majority of benefits you get from smart meters are not the operational benefits. It's the benefits that you get from employing those, those demand reduction rates. And so I think you have to -- you have to include that when you're looking at the cost benefits of smart meters.

But the main point I wanted to get to was I have a -- I got some anecdotal evidence or at least an anecdote, maybe it's not evidence, of pre-paying for bills. My cousin is executive director of an electrical cooperative

in a very low-income area. They really don't have the ability to have higher income customers pay for the arrears of the lower-income customers.

So they put in pre-bill pay. And what it allowed their customers to do is they could much more easily catch up on their debts. So instead of having 400 dollars in arrears when your meter is shut off, you have 20. And you can find 20; you can't find 400 as easily.

And so it allowed them to turn on their meters much more quickly. And I think that you could have a system if there is a weather event you can turn the meters back on and have the bills go negative. That's a good thing about a smart meter. You can press a button in a control center and you can turn it back on.

And I don't think that there's any reason why you couldn't do that if there is a extreme weather event.

MR. BERKELY: To ask one question about the area where the pre-paid was deployed. I went to the -- the NERIC conference a couple of months ago. And one of the presentations was about pre-paid. And one of the presenters pointed out that folks in the pre-paid who were having trouble with affordability got to the shut-off point 6 or 7 times in a month, as opposed 1 time a month.

So you're saying that someone might only be 20 dollars behind instead of 400, but how many times a month

are they have 20 dollars behind and have to find that money? Because for people who are on a very limited income, you have to -- and you have to time their bill pays. Getting 6 bills for the utility in a month is a lot different than getting 1, irrespective of the affordability underlying the problem.

MR. WAGGONER: It may be different based on the composition of your customers. If you have only a small portion that are low-income, then -- then maybe that sharing is different. But if you're -- they're all low-incomes, then it doesn't make sense to have other low-incomes -- low-income customers subsidize other ones. So you know, it could depend on, you know, what the makeup of your customers are.

MS. MIGDEN-OSTRANDER: There's one comment I would like to just quickly throw in. Prepaid should be voluntary. It shouldn't be mandatory on customers who don't want it and it shouldn't only be targeted to low-income. It should be targeted to any customer who wants it.

MR. LANG: Yeah, I agree.

MS. SCHERER: Great. Next question?

MS. SEIDLER: Maria Seidler, Dominion Voltage, Inc.

I just want to point out, because of the previous question about the cost of AMI and the importance of big data, one of the advantages of using AMI with voltage optimization is that you can increase the voltage

optimization saving. And there are demonstration projects that show that voltage optimization initiated on the grid can bring 3 to 5 percent energy savings that can give you a 4 to 5 payback period on some systems for the AMI

So -- and the great thing about initiating voltage optimization is that it benefits low-income customers without putting a burden on the low-income customers. I mean, they don't have to do -- take any kind of behavior. And for 3 -- if they're getting a 3 to 4 percent energy savings on their bill, even though that may not be a whole lot of kilowatt hours, every penny means everything to them.

So as we are talking about what's right for the low-income, there's a lot of things we can do on the grid side that can benefit those communities. And I do appreciate that the Staff has added voltage optimization on their distributed system planning requirements.

MS. SCHERER: Great. Thank you.

Panelists, thank you all very much.

MR. LANG: I'm sorry. Can I just make one quick observation here that I certainly agree with the folks who talked about being proactive? This particular panel wasn't about all the things we can do for low-income customers, it was about the incentive mechanisms, but I would very much hope and encourage the Staff to take away from this discussion that we should be looking at how we can be

proactive to help these customers. We should be looking at innovations as Peter and others have said.

There are many different things that could go on, but the focus should be on what we can do to help these customers and not on incentive mechanisms, at least in this category.

Thank you.

MS. SCHERER: Thank you all very much.

MR. OLMSTED: Folks, we're going to take a 15-minute break and be back here at 10:30.

(Off the record)

(The conference resumed.)

MR. OLMSTED: So we're just going to jump right into it again. If -- if you weren't here yesterday and I didn't get to introduce myself, I'm Peter Olmsted with Staff, and delighted you could be all be here this morning.

I thought the affordability panelist was a lively one. So looking forward to continuing the conversation. So without further ado, I would like to turn it over to Craig Henry with Staff who's going to moderate our next panel on market-based earnings.

All yours, Craig.

MR. HENRY: Thank you, Peter.

Good morning, everyone. So as you said, my name is Craig Henry. I'm a financial analyst who's been with

the Department approximately 27 years.

UNIDENTIFIED SPEAKER: Oh, my god.

MR. HENRY: So --.

UNIDENTIFIED SPEAKER: We should applaud that.

MR. HENRY: I was -- I was asked, slash, volunteered to -- is this on? I was asked, slash, volunteered to moderate the discussion on market-based earnings and I'm

actually very happy to do it.

The reason we're talking about MBEs is that they're anticipated to play an important role as the state's REV initiative seeks to transform the state's future energy distribution system into one where we will have fully developed DER markets in which utilities will be able to earn revenues from market-oriented activities in addition to the earnings they now earn from traditional cost of service.

And we're fortunate to have with us today a diverse and knowledgeable panel to discuss the topic of market-based earnings. But before I turn to them to provide their opening remarks, I've been asked to take about 5 to 10 minutes in order to provide some context on how MBEs are expected to fit into the broader REV-related transformation.

To do that, I'd like to begin by highlighting particular assertions in the Staff white paper that have been

the focus of a lot of comments. And I would like to share some recent developments, as well, that I think offer us some insight into this issue and are relevant to this discussion.

So you see up on the -- on the slide behind me, this -- really the critical questions that are going to be addressed by the panel and in fact, the Staff white paper asserts that a critical factor in the ratemaking treatment of new revenue sources, or MBEs, will be the extent to which the revenues derive from monopoly-like utility functions versus the extent to which they represent more competitive-type services, services that could just as easily be provided by third parties.

So based upon the questions posed in the Commission's notice for today's technical conference, I'm sure we -- we all can expect that much of our panelists' comments today will focus specifically on this very important issue. And there are a number of other issues as well that I hope we can dive into.

So now, into some more of the background for the context. The -- the white paper indicates that a primary driver of anticipated utility MBEs will be platform service revenues, also known as PSRs. And it states that the PSRs are revenues that the utilities will be able to realize by virtue of their capacity as the distribution system platform or DSP providers.

It's my understanding that the primary function of this new network platform will be to coordinate demand and supply at the distribution level and that in order to achieve this the DSP will have two-way communications and power flows among customers who could be generating their own power and multiple sources of energy supply, commonly referred to in REV as distribution energy resources, or DER And they include such things as rooftop solar, stored energy, and demand reduction.

The white paper also anticipates that the makeup, mixture, and pricing of MBEs will be driven more by market forces and innovation than by regulatory requirements. Nonetheless, we're going to spend a lot of time today talking about what sort of regulatory requirements might be needed.

Among the examples of such market-based services mentioned in the white paper are items such as customer origination via the online portal, data analysis, co-branding, transaction and/or platform access fees, and optimization or scheduling services.

So just like many of the commenters, I too am curious to see how the pace and scale of the industry transformation unfolds, and particularly, the diversity and the magnitude of new revenues that will be realized in a transformed distribution system that's conceived by REV.

As a financial analyst -- and you know,

myself, my office and are very interested to learn more about what we can reasonably expect with respect to the development of MBEs because of the opportunities and risks posed by the transformation on our utilities business model have very real implications in terms of the perceived risk and the accompanying return expectations of investors.

In other words, what impact will these changes have on ROE and on the utility's ability to track capital at reasonable terms. Since the white paper was issued, all 3 rating agencies S&P, Moody's, and Fitch, have all taken note of the coming change in the regulatory construct in New York. By and large, the rating agencies all acknowledge the inherent uncertainty that comes with such a change. And just as importantly for our discussion here today, they also recognize that this change will also provide significant opportunities for the utilities, as well.

For instance, according to S&P, opportunity will come from utilities that embrace the change and find ways to expect greater -- extract greater revenues from a grid that become -- that could become more valuable as customers place more value on the network to meet their needs.

And for its part, Moody's states, we believe it is credit positive that state regulators are encouraging utilities to adopt a business model that can help them stay

ahead of technological changes which are currently and certainly coming to the utility industry as a whole.

Also, at around the time the Staff white paper was filed, the utilities filed many demonstration projects. And there's some lessons to be learned from those. Many of the commenters have stated that the demonstration projects that have been filed with the Commission will provide opportunities to explore the potential benefits and challenges surrounding MBEs and provide stakeholders in the Commission with some real-world experience to inform their design.

These projects were filed with the Commission, as I mentioned, shortly before the Staff white paper was filed. And now that several of them have been approved, I hope that we'll have an opportunity to hear from some of the panelists a little bit more about the potential lessons that these projects might offer.

For instance, Con Edison's Building Efficiency Marketplace demonstration project anticipates numerous potential new revenue streams, including advertising fees, fees associated with an energy portal, and engineering fees. While National Grid's Community Resilience project projects potential new revenue sources including fees for providing essential procurement for DER, fees associated with the control and operations of the micro grid, and fees for

billing and financial transaction services.

So that's about enough for me. So I think all of us today are looking forward to the respective assessments of our panelists. Each of them are very well placed to provide informed judgment as to the factors that regulation should consider as the industry transforms.

So our panelists today consist of two representatives from the utilities. Stu Nachmias from Con Edison, he'll provide a Downstate perspective, while Peter Zschokke from National Grid can offer an Upstate perspective.

Additionally, we have Mike Mager representing Large Consumer Interests, Anne Reynolds representing a Clean Energy perspective. And Rick Umoff, the DER perspective on this area.

So at this point, I'd like to -- this is sort of how I see this going based upon how many of the other sessions have gone. I'd like to give each of the panelists about 5 minutes or so to provide their -- their introductory remarks. The Staff team has assembled a number of questions that we would also like to pose the panelists.

Then we'd like to turn it over to the audience for some questions and then finally, give our panelist an opportunity to make some closing remarks.

So I anticipate that each of the panelists is ready with their remarks and I'm also assuming we can start

with the utilities and then sort of go along the same line as I introduced you folks.

So take it away.

MR. NACHMIAS: Thank you. It's on; right?

So thanks to Staff and Craig for your assistance in -- in inviting us and in helping us to prepare for the panel.

I will say, maybe to make you feel a little bit better, my 27th anniversary at Con Edison is coming up very shortly. I think I started when I was probably 15. At least in my head, right, how did this happen.

You know, it's interesting as I was thinking about that, when I started at Con Edison one of the first terms I started to hear about was rate-based and revenue requirement. And I quickly, having just finished an MBA in finance, pulled out my corporate finance textbook and tried to look in the index what is rate base. And it wasn't there.

(Off-the-record discussion)

MR. NACHMIAS: And so I looked at, you know, revenue requirement rate base wasn't in the corporate finance textbook that I had used. And it took me a while to figure out -- not too long, but it took me a little while to figure out what was this and why -- why is this different for utilities.

And obviously, I've come to -- to learn over

those 27 years that the fact that utilities are regulated entities, that we have a rate base and revenue requirement, our return, equity return is set by the regulator based on information about the market and allows us to raise funds, raise the capital needed for long-term investments, both on the equity side and access to low cost debt.

And I raised that because I think the fundamental premise is that we are utilities. Our investors invest in utilities because of the regulation, the rate base, and revenue requirement that results from the process of regulation. And that is something that is core to who we are and what we do. And our view as utilities is that that remains as we move forward through REV.

And certainly the business model and what we do is evolving, but the types of investments and how we work to accommodate distributed energy resources in the future and to move to a cleaner, more resilient, reliable, safe, affordable future remains with us as regulated utilities. That's not to say that -- that some of us don't have affiliated companies that are more competitive in the marketplace, but the core business that we're talking about today is in the regulated utilities.

And -- and therefore, it's important to note that as we invest in technologies and we have data and information, we do that as regulated utilities. And the

platform services revenues that we're talking about is how the utilities would be able to gain revenues from being, in essence, a facilitator of third party -- third parties in the marketplace. And those revenues are really important and it's how we will recover or one of the ways in which we will recover our revenue requirement.

The market-based earnings that are being discussed is sort of a subset of the platform services revenues. And I think what's really important to think about, which we do are very often in utilities, is how is the revenue requirement that we generate, how is that recovered from customers.

And what's important here is, unlike in the past where we took out cost and we do class of study -- class studies and we assigned cost to customers, there are customers that are going to participate in different types of products and services. And so as they use information or as the utility can actually leverage its role to help and work with third parties, it can get additional revenues.

Those revenues should go against the revenue requirement to benefit all customers and, in particular, to help reduce the costs to customers that are not participating by obtaining revenues from customers that are more active in participating and should be willing to pay for those products and services offered by the utility because the benefit

they're getting would outweigh the revenues that they are giving to the utility for that -- for that assistance in that role.

And so as we -- as we think about REV and we think about the platform services revenues, I think it's important to think about what are those revenues, how is the utility generating that, and then what is it doing to -- you know, in using those revenues to help benefit both participating customers and non-participating customers. And that's the framework under which we are very much thinking about this. So that's an important piece.

I -- I think, as we consider those revenues, you know, we certainly might want to consider should utilities have an incentive. So if we want utilities to be able to achieve those revenues and make sure we are helping third parties and maximize those -- those revenues because it's good for all customers, right, maximize maybe in a way where it's -- it's helping the participating customers in a fair way but also others, having utilities perhaps retain a share of those and -- and a small share of those -- those revenues might be a fair incentive and something to be considered. But the bulk of those revenues should go back to customers.

So -- so I think there are two other issues that sort of come up when thinking about those revenues that

-- that has been in the comments of the utilities and other parties, which is what is the pricing of those products and services, how should those products and services be priced. And I think the thought of the utilities is that we want a fair price, but it could be a value-based pricing should be an option that is on the table because the value that those participating might be more than the costs. And so the objective should be that those participating should be willing to pay based on the value of those products and services.

They should get value in the end that is greater than what they are paying the utility. And those revenues then ought to be used to help benefit the customers that are not participating and not electing to buy those products and services.

So I think that's a very important part of the premise that we -- certainly has been teed up in the discussion. And I think that there's more discussion that ought to be had on that.

And then last, the question -- the other question that comes up is what are the products and services that the utilities are providing and that they should not be competing with third parties. And I think from the utility perspective, what's clear is we see ourselves as a facilitator and using our role to help facilitate third

parties.

The Track 1 order clearly has stated that distributed energy resources, behind-the-meter resources, will generally not be provided by the utility. And so we are not looking to provide the same competitive products and services that third parties do, but rather, to facilitate third party participation. And they're offering products and services to customers.

And so just one quick note as an example and we can get -- get into this more, but in -- in many of the demonstration projects what we are trying to do is help third parties identify customers that would want to use the products and services of third parties and to gain revenues because we are helping those customers locate, identify, and obtain customers.

And so therefore, those revenues that we would achieve would then be used to benefit all -- all other customers.

So I'll stop there. I think that hopefully tees up where the utilities are and how we see a platform service revenues potential for market-based earnings and the other key issues of the products and service offerings from utilities.

MR. ZSCHOKKE: Ditto. Thank you.

MR. NACHMIAS: Peter, you've just been on too

many panels.

MR. MAGER: Okay. Well, I'll take Peter's time then. So --.

MR. ZSCHOKKE: I'll expect you to pay me back later.

MR. MAGER: -- so if you were here yesterday, you know, I'm -- I'm not a big fan of EIMs, especially how they have been proposed in the white paper. Maybe it will be a surprise to some, maybe not, that I think market-based earnings, in contrast, have the potential to really benefit consumers, as well as utilities, depending on how they are structured and implemented.

And that's, I think, the key point. And my focus, not surprisingly, is on consumer benefits. And that -- the way we look at it, that's really the reason we're doing this, why the Commission is undertaking REV. And you know, if we get to the point where utilities and ESCOs and DER providers are all benefiting but consumers are not, then I think REV is going to go down as a colossal failure. So I think the focus really needs to be on consumer benefits.

And in particular, MBE should be managed in a way that ensures that they are beneficial to customers and result in a -- an overall reduction in utility rates for the provision of monopoly services.

So with that intro, I'd like to offer my 6

commandments on how to implement MBEs.

1, the PSC shall go slowly on MBEs. The development of DSP services and MBEs likely will take many years. Take baby steps. Don't try to do too much, too soon. The market will decide what new products and services have merit.

2, utilities shall not use their monopoly position to gain an unfair advantage and/or inappropriately exercise pricing power in markets that should be competitive.

3, the PSC shall ensure that MBEs are limited to new products and services that provide additional value, either to suppliers, customers, or other third parties, above and beyond traditional electric service that's already governed by and paid for through tariff-based rates.

4, MBE shall reflect an equitable sharing of revenues between customers and shareholders. Now, let me take a second to explain what I mean by equitable in this context. Where the utility is relying on its monopoly position and it's using information systems or people or other investments or assets that have been funded by customers, then customers should receive the lion's share of the revenues.

Conversely, where the product or service is being offered is truly competitive and the utility is spending or risking shareholder money to offer and provide

such product or services, then it would be appropriate to allow shareholders to retain a larger share of the revenues.

5, customer share of market-based revenues shall be used to reduce rates to customers. Let's not divert those revenues to pay for the next great idea. Let's use them to reduce rates.

6, the PSC shall actively oversee prices charged for DSP products and services. How? If the -- if the products and services are offered only by utilities as a result of their monopoly status, they should cost-based because they're not competitive.

On the other hand, if the products and services are truly competitive, and by that I mean the product or service is not covered by existing rates, it's not reliant on the utilities monopoly status, and can be provided on a comparable basis by other parties, then market-based rates or value pricing, as Stu said, would be appropriate.

And I think -- the one thing I'd leave you with is in a way market-based earnings are a form of an EIM I had a brief conversation with Rudy about that yesterday. Market-based earnings do provide financial incentives to utilities. But I think there are a couple of big differences between the MBEs we're discussing today and some of the EIMs that have been proposed.

The first one is to the extent MBEs are

realized, to the extent market-based earnings are actually realized, you would know that benefits have been provided because ESCOs, developers, or customers are actually choosing voluntarily to purchase value added products or services.

2, unlike EIMs that are -- are going to be presumably paid for by all customers with MBEs, only the entities that are voluntarily choosing to procure the products and services are going to be the ones paying for them, not all customers.

And third, unlike EIMs, which have the potential to raise rates, and we would say are very likely to raise rates as proposed, MBEs should be implemented in a way that actually reduce rates for monopoly services by offsetting a part of the revenue requirement.

Thank you.

MS. REYNOLDS: Good morning, everyone. I am Anne. I work for the Alliance for Clean Energy.

You probably never thought you'd hear me say this after going after Mike, but ditto. Actually, there is a remarkable amount of alignment between, I think, what I've heard so far and our position.

I should add East New York is working in close partnership with the Advanced Energy Economy Institute and NECEC And so I'm here today representing the position of all three organizations and our member companies.

So -- and to summarize, our comments on MBEs essentially it was a message of caution and gradualism. We don't think that MBEs should become a major and significant part of utility revenues in the near term. We, in contrast actually to what was just said, like the focus on EIMs in order to motivate actions that will -- will grow the market for DER.

But -- and we also don't think MBEs should be allowed in the near term for competitive services. But that said, let me be a little bit more positive for a moment. We certainly understand and support the motivations for having market-based earnings and fostering innovation at the utilities and creating new products and services that customers want, and offsetting on the general rate base some of the potential costs of investments in the DSP, those are all to the good, as was said.

But we think this needs to be balanced. Those benefits need to be balanced with the risks to grow from the DER market in the short term.

So in our comments we distinguished between platform service revenues and competitive services, and further distinguished between platform service revenues that were essential services related to operation of the distribution system and those that are value added such as operation of a customer engagement portal.

The second category is in -- you know, is in grid operation. And in fact, other parties could provide those services, but if the Commission decides, because of pragmatic reasons or reasons of public policy, that that is a role for the utilities, it certainly is related to their -- their role as the DSP. And they could gain revenues in that -- in that -- in that area of operation as was described because of advertising or transaction fees or fees to use the platform.

Our position is that both of those types of platform service revenues should be open to market-based earnings. We think that that's fair territory there. And it -- all of those activities could be seen as those that are necessary to grow the market for DER and to enable and facilitate the market for DER, as Stu was saying.

In contrast, there's competitive services that could be offered by third parties and we think they should exclusively be offered by third parties in the near term. So things like engineering services, consulting services, energy efficiency, audits, for example, are not things that we think should be included in the realm of the possible for MBEs in the near term.

And that -- and that restriction, our position there is based on two ideas. One is that we'd rather see the innovation at the utilities focused into

activities that will grow the DER market, rather than directly compete with DER providers. And we think that, while it's theoretically possible to allow the utilities to act in that arena, it would be very complex and difficult to fully police how you'd have a fair playing field there. Not impossible, but certainly we think so complicated in the near term that we should put that off to a later stage in REV.

So, I'll stop there.

MR. UMOFF: All right. Hi there. I'm Rick Umoff for SEIA. Thanks for having us. We are the National Trade Association for solar companies. We've been engaged in REV since the beginning and engaged in Track Two.

I agree with Anne that there seems to be a lot of actually more agreement on this panel than -- than I may have thought which is, I think, a good thing. I think when we're thinking about MBEs, PSRs, EIMs, and really the future of what this platform's going to look like and how it's going to be built out, there's a few themes that we -- that come to mind for us

And the first is market power. You know, we're really concerned about ensuring a balance of market power. Functional separation between the utility and the DSP, also the monopoly versus competitive market. Types of -- and finally, types of earnings, cost-based earnings versus competitive earnings.

When we look at REV, and I say this an organization who is very excited about REV and heavily invested in the success of REV, but we believe that the decision to allow the utility to operate as a DSPP. and build out the DSP has created an inherent conflict of interest at the heart of REV.

And rather than focusing on market-based earnings, the Commission right now should be focusing on setting up a neutral platform that guards against this conflict of interest. And the burden now going forward, given the structure that we have with the utility operating the DSP, is going to create a bit of a burden on the regulators to mitigate this conflict of interest going forward.

We believe the Commission should identify monopoly functions for the utility earned regulated returns and focus on developing a satisfactory cost recovery for those functions, at least a neutral platform and enables third party participation.

Utilities should provide the monopoly functions and competitive functions should be provided by non-utility market entities. And the Commission should clarify that utilities' role is limited to monopoly functions are uniquely enabled by the utilities' monopoly status for which the utility will earn a regulated return based on cost

of service through rates established by tariffs. And these tariffs may include platform service revenues or EIM, as well as traditional collections based on customer usage.

The Commission should disallow competitive utility functions in the REV market to avoid using ratepayer funded assets and personnel for shareholder benefit and to ensure that competitive entities have the confidence and fairness of a neutral DSP in competitive market.

And we think the focus should really be not just on establishing a neutral platform, but also a DSPP. that's defined functionally and possibly structurally separate from the utility.

The DSPP. should file with the Commission for cost recovery through one or more DSP-specific tariffs that are not combined with any other utility tariff or service classifications although these tariffs could -- and these tariffs could include PSRs and EIMs.

Once the platform has been established and shown to be effective, that is when we can start to look at additional functions or services that the DSP might provide. However, that should only be done in the context of always considering whether the functions or services are better provided by the competitive market participants. And it should be made clear that PSRs are cost-based charges for accessing and using platform services. We see PSRs as an

effective mechanism to allocate cost to entities that use the platform services, which is appropriate to enhance efficiency, allow the DSP to recoup its cost as a monopoly of service. and potentially provide an opportunity to offset loss of kW sales.

But until the Commission is confident that it's established a neutral platform that is facilitating a robust DER market, we think that a focus on longer term MBEs or competitive-based earnings of any kind really should not -- should not be there.

And I think that pretty much wraps it up. Thanks.

MR. HENRY: Thank you all very much. So we -- we the Staff team has a few questions.

MR. NACHMIAS: Can I --

MR. HENRY: Is there something --?

MR. NACHMIAS: Can I just -- I just wanted to comment. I mean, having spoken first and then -- then hearing the others and particularly Mike's, you know, six commandments, I just want to say that, almost ditto to what I've heard, as well, but there are two things I wanted to point out on -- on Mike.

So one of the -- one of the commandments said something about sharehold -- you know, that -- that customers should get the bulk of the revenues with the exception of if

shareholder money is used. And just to be clear, going back to the premise of these are regulated utility investments, we don't expect that shareholder money will be used within the regulated utility for these kinds of investments. If that happens, that happens in the affiliated -- you know, competitive affiliated different companies. So to be clear, we're talking only about things that are being done as a facilitator. So I wanted to make that -- that part clear.

And then -- then the other piece, because it was ditto on everything except for this one, that that all of those revenues and the pricing ought to be cost based. Just on that, sometimes the cost is going to be pretty low, but the value is higher.

So as an example, if we're helping a third party to save a customer money to participate in some sort of demand response or energy efficiency program or to maybe procure solar and that customer is going to save a lot of money and the third party is going to really have a profit in that that's significant, we think that we ought to be able to price our service based on the value that the customer and the third party is going to get as a way to get the most appropriate revenue that then goes back to all other customers.

So I just want to be clear. That's why we're thinking that really it could be cost, but value -- it could

be value also. So those were the only two pieces.

And frankly, just to go out on a limb on -- on the whole concept of market-based earnings, at least for us I think for the utilities if we never had this acronym and we focused on platform services revenues and, instead of market-based earnings, just said we're going to share the revenues in some way where a small part will go to the utilities as incentive to achieve the revenues, but the majority will go back to customers, and talk about what are the platform services that we're going to provide, I think we as utilities would be just as happy because I think that really focuses what we're talking about here, not market-based earnings where we're putting shareholder money at risk and not where we're competing with other third parties in the products and services.

MR. HENRY: Okay. Mike?

MR. MAGER: I just want to -- sorry -- I just want to reply a little bit.

So the utilities' decision not to put any shareholder money at risk raises a couple of issues or warrants a couple of responses. One, I guess, if -- if the utilities are looking for the customers to fund everything, then -- then their share of the market-based revenues truly should be significantly small under those circumstances.

But it also, I think, places increased

pressure on the PSC and Staff in terms of deciding what -- what products and services are offered. You know, for instance, who gets to decide that customer money should be spent to offer the services to gain this capability? Because I'm assuming that what's going to be offered through this -- through this vehicle is going to be new products and services, not the existing stuff that's are -- that you're already doing, that's already covered through rates.

And so if these are new products and services, does the utility get to decide how much customer money it gets to invest in the hope of offering it? I think that raises a lot of concerns from the consumer standpoint, whereas I would favor some type of system where the utility shares in the benefits and the risks of those investments because I -- I don't want the utility necessarily deciding to invest customer money to voluntarily offer a service that may or may not be needed or may or may not be of true value to the market if the utility has no skin in the game.

So that's -- that's my response.

MR. HENRY: Anne?

MS. REYNOLDS: See, we're not going to even let you ask us a question. So I just wanted to respond to that, too.

I mentioned that in our written comments we made this distinction between two types of platform service

revenues. And part of the reason we did that was to answer a bit of what Stu's question was. So the first type that what we refer to as essential platform services that would be, you know, exclusively using the investments that had been paid for by ratepayers, that should be cost of service.

But that on the value added platform service revenues, that may be more appropriate to do, as you say, and have the price be based on value.

So -- so we sort of wanted to make that distinction in part to answer that question, and did say though that there remains a concern there that if the utility is the only one providing that -- that -- say that digital marketplace or whatever it is, the customer engagement portal, that there still is some concerns about what the price would be set at because you'd be the only one providing it. And mentioned there that maybe that's worth an important interaction with the EIM for customer engagement because if you had a separate earnings impact mechanism that would make the utilities have their interest be aligned with a robust customer engagement portal, then you wouldn't want to set the prices too high that people wouldn't take advantage of it. So that the two mechanisms could work together.

MR. ZSCHOKKE: If I could? Just as a point of order, everything the regulated entity will do will have to come before the Commission. We will have to make a

proposal. You know, it'll start with the DSP plans that are coming forward in -- in -- in the -- later in the year. The Department's -- the Commission's going to have to review them, decide what they want the utility to do or not. Everyone's going to have a chance to intervene and argue about what we should do, what we shouldn't do.

So there will be full investigation, unlike most of the other third party actions who can choose to do what they want to do because they are risking their own shareholder capital and they won't necessarily be under the guise of the PSC authority.

But for us, for what we are doing for these platform service revenues, we do expect that they will be overseen by the PSC and that we will have to ask for authority to charge any platform service revenues that come forward. And, you know, maybe ten years down the road things may change, but at least for the time being we will be under the authority of the PSC, and will continue to do so.

So I think people's worry about whether or not they will be -- you know, we will make the decision to do something independently without the -- getting the authority of the PSC to say yes, you should, I think that's -- they can -- you can worry less about that, Mike.

MR. UMOFF: If I could just quickly?

MR. HENRY: Go ahead.

MR. UMOFF: Just kind of building on Anne's comment about those kind of different types of PSRs. You know, we think it's -- it's pretty early in the game to be talking of value, sort of value added PSRs. And you know, it's going to be really important to make sure that we give the competitive marketplace the opportunity to offer those -- those services as much as possible and -- so that we don't have a situation where the utility is sort of playing that role even, maybe, you know, by accident because the opportunity wasn't there for the competitive market to kind of get going and provide some of the services that -- that they could be providing.

MR. MAGER: I -- I just want to address this pricing issue as -- as well. To the extent the utilities are allowed to offer products and services that are truly competitive that other entities can similarly provide, then I think value-based pricing has a role and I don't necessarily oppose it.

But where the product and services offered only by the utility as a result of its monopoly power, we feel much more comfortable with cost based pricing. I think there is something to -- that has to be remembered. I mean, Stu gave an example of, you know, what if, you know, we're doing something that it may not cost us a lot but for the ESCO it provides a really big benefit and so, you know, we

think we can charge a higher price for it.

I think it's important to realize that, you know, whether it's to an ESCO or developer or whoever is buying this product and service, the cost that the utility charges them is going to be passed through to the consumer at the end of the transaction. Consumers are going to be paying for this.

And so the issue, as I see it, is whether they pay it directly by purchasing the product or service, themselves, or indirectly through a third party, they're going to be paying for it and should they have to -- should that charge be a value-based service for something that the utility is providing under its monopoly power. And I think the Commission should stick with cost-based ratemaking for those types of products and services.

MR. NACHMIAS: So just to respond to that, I think you make a -- a good point. I think it's really a matter of allocation of the cost. And so today, you know, most of, if not all of the cost of the utility are generally socialized to all customers via rate class and ratemaking methodologies.

What we're just trying to say here is the revenue requirement, we should have a way where those -- where we're differentiating more. And those customers that are actually participating and taking advantage of those

platform services that are being offered ought to pay perhaps based on the value only because what that does is it gets us the revenue that can offset the revenue requirement to minimize the net revenue requirement that has to be socialized to all other customers.

Meaning that those customers that are not taking advantage of those products and services don't have to pick up a -- a share of it. So -- so we just may not, you know, want to socialize as much. So it's a way really to reduce the net revenue requirement for those products and services that has to get socialized and paid for by all customers.

It's really just a shifting. I mean, if there is a decision that everybody ought to pay the same, whether you're participating or not, that's a decision that ought to be made. Our view was we ought to be able to get the -- a fair revenue from those that are actually using those products and services.

MR. ZSCHOKKE: Yeah, I just add to Stu's point to mean -- Mike has -- has put out one -- one side of the equation, which is we do things cost based, we'll have a rate, we'll have tariff. It will cost X to do Y.

But keep in mind that as a platform, we will be providing services to businesses who are trying to act in the market. And these businesses have knowledge about their

customers. They have knowledge about what they're going to offer. Should the utility -- and I'm not saying we should or shouldn't, I think we should, for the benefit of all customers, but should the utility be able to, you know, maximize through negotiation the revenues they can get from those services in order to offset the costs of service?

Or should we be restricted to only to -- to having a proceeding before the Commission and charging strictly one number that everybody knows? What will be the construct we will create in order to provide benefits for all the customers, knowing that this will be a business transaction? You know, we may have to come forward with a construct to the PSC to get it approved by transaction, but it will be a business transaction between people who -- who have their own financials, have their own numbers and, you know, are we -- so what kind of a construct we will allow to deliver platform service revenues that do help reduce the cost of service to all customers.

MR. MAGER: No, go ahead. I feel bad he's just standing up there with nothing to do. Go ahead.

MR. HENRY: Well, thank you for all your thoughtful insights there.

One question that -- that -- that comes to mind, since we're -- you know, we're -- the discussion's come up as far as how much shareholder money would be at risk with

the platform. And the Staff white paper notes an instance in the gas delivery business where there is -- there's no shareholder money at risk, but that the utilities are able to -- they're able to realize revenues from capacity releases and they're typically shared somewhere in the -- somewhere 85/15 percent, 85 percent to ratepayers, 15 to shareholders.

So I was just wondering what the panelists feel what sort of insight that would be for -- for the -- with respect to the platform?

MR. NACHMIAS: I think it's a good analogy. Right? It's where under regulation a utility has contracted for a pipeline capacity. There are times where that pipeline capacity is not needed by the utility and so there's a market for release. The revenues are obtained from that. It is a market-based revenue, in essence. And those revenues go back to -- the majority of it back to the customers that are paying the regulated cost of that pipeline service and with a small piece to the utility that gives it the incentive to release.

Otherwise, the utility could simply say I don't have to release it, I'm getting the full recovery of all these costs. But the incentive is to lower the net cost of that capacity to all customers. So it's -- it's really quite a similar analogy.

MR. MAGER: I think -- I think there are some

differences. In the -- the capacity example, the utility has procured capacity that was thought to be needed and there's some excess capacity there. The investment has already been made and so now they are trying to maximize the -- the revenue to offset that prior investment.

This is, I think, a little different. I -- I guess I confess. I'm not totally comfortable with a situation where utilities get to, you know, propose what -- what capabilities they're going to have, what products and services they're going to offer into the market, what pricing they're going to use for these products and services and they're going to make all the underlying investments at customer expense, and not have any skin in the game, so to speak.

I -- to me, that -- that's not the appropriate way to do it. Where -- where there is something that is truly -- you know, where something that's truly a monopoly type service where -- where the utilities are actually putting up little to nothing of their own funds, there should be a vast majority of the money going back to customers.

And I -- I would not be comfortable with the 15-percent figure used in that context. But I do think there is opportunity for utilities to earn greater revenues where they do step up, put some funds at risk or offer products and

services that are truly competitive.

MR. HENRY: Anyone else?

MR. NACHMIAS: Just one thing on that. All of the products and services that the utility ultimately will offer will not necessarily be the result of incremental investment. So as an example, right, utilities may make investments in DSP technology. And we're doing that for a variety of reasons including that we need to do it anyway because we need to have greater visibility into distributed energy resources and we need to operate the system with -- with more clarity, transparency, and knowledge of what -- what is happening on customer side.

So as we -- as we advance the technologies that helps third parties to integrate, but also allows the utility to operate the system, there may be product and services that make sense to help third parties that aren't necessarily the result of incremental investment but can provide revenues that go back to the investments that already have been made.

And that's -- that's similar to why I think it's similar to the gas scenario, where in that case utilities have already made the commitment they had to, to get the pipeline capacity for firm customers on the cold winter day, but in other times of the year it's available and so there's an opportunity to make additional revenues. I

think it's similar here.

And so I think there's a -- a degree of flexibility that would be needed as we determine what are the additional product service revenues and product services that would be available. And really the goal would be to have revenues that can be used against that revenue requirement.

MR. UMOFF: I mean, I think I can definitely see some parallels. I think one of the challenges it's -- to me it seems like a much more simplistic scenario than that we're looking at under REV. You know, the REV platform is going to be much more dynamic than that. And you know, what we're concerned about at this such early -- this early stage is making assumptions about what the competitive market can do or will do if a neutral platform is established.

And so, you know, we just, you know, caution to move slowly in terms of deciding which sort of platform services or value added services is appropriate for utility to offer when we -- we don't -- you know, we don't know -- we can't imagine some of the services and products that could be provided on this platform if established correctly by the competitive market, so.

MR. HENRY: Thank you.

So we've also heard a lot of -- it seems like it's difficult to have a discussion about market-based earnings without also discussing earnings impact mechanism.

So I just wondered if any -- any of you would care to comment how you see the interaction of earnings impact mechanisms and MBEs as -- as REV rolls out?

MS. REYNOLDS: Well, I can -- one example is what I mentioned before. You can imagine a situation where the utility is running a customer engagement portal and is also -- has a digital marketplace where there's transactions that are taking place. They're earning revenues from customer origination or referrals or advertising or fees for transactions, but they're the only person -- the only entity providing that service in that way. So you'd want the price to be fair, but it might be appropriate to have it be based on value, not just on cost of service.

So the EIM would be critical in ensuring that the utility wants there to achieve a certain level of customer engagement, a certain level of transactions so they could work together in that way to -- to make the utility want to have a price that's working to have the -- the market be robust.

MR. HENRY: Anyone else care to offer anything else?

Okay. So another question from the -- the Staff team would be, you know, as you know, REV contemplates an interest in spurring partnering relationships and the benefits associated with those relationships. What

opportunities do you see in this area?

MR. UMOFF: The opportunities between the -- I'm not sure if I fully follow the question. Can you repeat?

MR. HENRY: So REV is contemplating -- it contemplates an interest in spurring partnering relationships and the benefits that are associated with those relationships. So what opportunities do you see for this to occur?

MR. UMOFF: And by relationship, you mean relationships between the utility and the -- and the service providers, a third party?

MR. HENRY: Right.

MR. UMOFF: Again, I feel like we're sort of looking -- we see that -- we see a future -- more dynamic future and a more dynamic market down the line. But we think -- and we're encouraged by that vision, but we think that we're -- we're just -- we're not even close.

And it's a bit concerning to start to think about, you know, bilateral -- bilateral contracting or -- or some kind of partnerships where the role of the utility starts to seep into the competitive marketplace and it becomes a bit blurry.

And so, you know, we -- we -- you know, we do see some opportunity there potentially for maybe certain carve-outs where, you know, the utility and -- and the

service providers -- it does make sense for them to -- to have some partnerships. But we -- we just don't think we're there yet. The focus really needs to be on establishing a neutral platform.

MR. NACHMIAS: Can I just -- I would just say I think that an example are some of the demonstration projects that you alluded to. So where the utilities are working with a variety of third parties to either develop a platform or maybe to help.

In one case, Con Edison, we have a virtual -- the virtual power plant project where we're working with solar companies, helping them to identify, acquire customers, and to help make -- help make the product and services sale so that it helps not only the utility, it helps the customer, it helps -- actually the customer probably first and foremost, helps the third party.

And so I think that there's a variety of ways where those kinds of relationships will evolve and continue to evolve because clearly the -- the utility has a role to be able to help and work with a variety of third parties.

MR. MAGER: I guess I -- I largely agree with what Rick said. And I -- I think, you know, that there may be kind of informal partnerships in that the utility as the DSP provider is going to have to know what products and services are desired by the marketplace and so they're going

to be, I imagine, interacting with other parties.

But then actually providing the service, I think it's critically important that they remain neutral. And so, you know, you wouldn't want them necessarily having a partnership -- a formal partnership with one supplier on a particular product or service because what would that do to the other potential providers of that product or service.

So, you know, I think -- I think the utilities are going to have to be responsive to the marketplace and get inputs in terms of what products and services are actually valued by the marketplace. Of course, unlike my colleagues, I'd prefer them to have some skin in the game to really do a good job with it. But either they do or they don't, they need to -- they need to be cognizant of what parties desire, what products and services are desired that they are particularly in a position to provide. But they can't enter -- I guess, I -- I have some concerns about them entering into formal partnerships with individual third parties.

MR. HENRY: Well, thank you all very much for some -- your wonderful insights here.

I'd like to offer the audience an opportunity to step up to the microphone and ask questions. And as others had mentioned before, please state your name so the record can have it clearly.

MR. ZSCHOKKE: If -- if I may just add to Mike's point? A partner that you have a single relationship because they want to bid, that's a vendor, not a partner. They're still under your management control. Partners should be somebody who actually put some of their skin in the game if not all of their skin in the game for what they are doing for their business purposes and they are just aligning so that they can -- they can get sort of customers more effectively, so.

MR. HENRY: Thank you.

MR. LEONARD: Hi. Ron Leonard.

First, I want to address the veterans on the panel here, 27 years. I've been in the cogeneration business and solar energy business --.

UNIDENTIFIED SPEAKER: Ron?

MR. LEONARD: Yes?

UNIDENTIFIED SPEAKER: Turn your mic on.

(Off-the-record discussion)

MR. LEONARD: So I've been in the cogeneration business and renewable energy business since 1975. You can do the math.

I wanted to address Con Ed a little bit. My father worked for Con Ed for a little while, basically 8 years after World War I until the early '90 -- excuse me, until the early '60s. And the reason I bring him up is that

I think in that period the utilities had a fair relationship with the public at large. There was a regulated utility that offered fair service.

And I think the relationship might have shifted since that time. That the utilities -- well, look at the proceedings that we're addressing right now. The utilities really are operating very -- like a very strict monopoly. And you look at the proceeding response from the utilities, you'll see that all the utilities respond with one voice.

So I am wary because of that. I'm wary my -- by the simple proceeding that we're having right now, we're trying to give the utilities a way of surviving in this new era, you know, actually forcing them to offer services that people want to buy, which is unique.

And in -- in that instance, that service that they want to buy and offer, the fair trade is by being a monopoly you have market power that's one-sided. And what I'd like to bring up as an example about one-sided market power is cogeneration where you can offer a disconnect fee that makes cogeneration basically uneconomical. Famous example is Durst in New York City.

So I'm wary about the proceeding moving in a direction that favors utility over the public. I'm wary about the participation in non-utility people in the process,

our friend here from SEIA. It is vital for groups like that. I help organize SEIA in 1994, along with Peter Lowenthal. These groups, these -- these non-paid consumer advocates on these proceedings are the life and breath in terms of making this work.

You know, I sort of find myself relating to the business counsel's argument that offering utilities too much leeway, too much rope will gear the system in such a way that really the consumer doesn't have the benefit of these new opportunities under REV. And that, I think should be the topmost criteria in terms of offering new services.

MR. HENRY: Thank you.

MR. WAGGONER: Hi, I'm Danny Waggoner for Advanced Energy Economy Institute. I have a couple quick points.

One is regarding -- I heard something about utilities being able to negotiate prices for value added services. And to me, that could become problematic if you have, you know, one utility, one provider.

You have lots of third parties, you could sort of create discriminatory relationships and maybe you could still have value-based pricing, but it could be transparent and non-discriminatory. So you list a price. It may not be cost based but you list a price and so that way you could, you know, avoid that potential problem. You

wouldn't be able to negotiate prices, but you could still potentially have a base pricing.

And I wanted to compare the AEEI position and the SEIA position. I don't think that there's really that much difference. There may be just a little bit of difference in the definitions. I -- I think that -- you tell me if I -- if I'm not comparing them correctly. But I think both groups are not for competitive services such as data services, engineering, et cetera, things that could be provided by the competitive market. The AEEI and its New York position does allow for some potential for value-added services leveraging the existing utility customer relationship.

And that's where we see that, yes, you could have a third party or some unrelated group do advertising and help originate customers. It just wouldn't be as effective instead of if you used a utility. And so that's where the value-added platform services come in.

Is that accurate?

MR. UMOFF: Yeah, I think that's -- I think that's a pretty fair characterization. I think we're still fairly conservative on our perspective on the value-added services that the utility should be providing given the early stage of this REV process.

MR. NACHMIAS: I would just comment, Danny,

that -- that I -- I think you're right in terms of the value-added pricing. I think we need to talk more about, you know, what process we'd have to identify what that pricing ought to be. And with respect to the -- the value-added services, I also agree with -- with what you're saying.

The one clarification I'll say and it's in a separate kind of set of technical conference, the data sharing and the data piece is sort of, I think, another area where more work is just ongoing.

MR. HENRY: Thank you.

MR. FULLER: Hi. Pete Fuller with NRG. And like many here, I think, today I was not prepared for this level of violent agreement on this panel. And I may share in some of it, frankly.

But I think -- let me offer sort of my articulation of what I think I've heard or what I've sort of synthesized and I'd appreciate your reactions to it. And I think, Stu, you -- probably your -- one of your points was probably the most valuable to me today was if we didn't have this thing called market-based earnings but we just talked about platform service revenues that might be priced differently, maybe it all, maybe it makes more sense.

So what I would like to offer as a suggestion to think about is if we start from the premise that the -- what we are talking about this stuff is things that are

really uniquely the province of the regulated entity. For whatever reason the services and the products we're talking about are only those that can come from -- because of the utilities' position, it's asset based and so on and so forth. That's one of my premises.

And then the second one is that where it is -- well, the -- the -- the question of pricing really becomes the issue then. And I guess I would ask for your thoughts on the points that are -- or the exploration that's been had about, you know, could you negotiate a price, Peter, or -- or what have you or -- or is there some other way to price.

I think the example of the pipeline or renting space on a pole for somebody to attach or -- or something like that, I think that's a good analogy of using or -- or gaining revenue from otherwise unused assets. I think it gets much more complicated when you talk about having Staff that otherwise would be doing something for the ratepayers directly, doing something for a paying customer off to the side.

And so, I guess, I'd like to get your reaction to my first premise about things that are uniquely available to the utility. And then just maybe explore a little bit the challenges of different types of services that might come along and whether there are actual markets for them or whether there are one-off requests from NRG to

National Grid. Can you do X and how do we settle on a price and in the vacuum like that?

MR. ZSCHOKKE: Well, I'll address the pricing issue. I mean, you know, I threw out the construct earlier simply because there is no structure right now for how we would do this. So -- and that's -- these are the considerations we have to have.

We want to promote the market but at the same time want to get the revenues. And -- and the question is how do you maximize those revenues. Do you want to maximize the revenues? Because Pete, you're perfectly right. I mean, we will have people who will be working on the market element that could be doing utility work regularly. And so if they're not doing utility work, we'll have to have people doing the utility work. So that's a cost that has to be recovered preferably from the platform service revenues first and then whether or not there's anything added over.

And that's all stuff we are going to have to work through as we go through this process and we see what the real offerings are, what it takes to offer them, and what we perceive as the market acceptance of those, which the utilities have mentioned in their comments.

I mean, I've heard a lot of people say we just don't want to pay for it, which means the market platform service revenues for some things would be zero. So

what -- does that mean we go forward with certain constructs to -- because we think it's a good idea? Or do we then say no, we're going to have our fee anyway because we think that's important to see what would happen?

And if we get revenues out of it, do we then adjust it based upon our experience or do we keep it the way it is? Or if we don't get revenues from it, do we then adjust the -- the prices out? That's all something we have to learn as we go forward in this process.

MS. REYNOLDS: So I guess I'm just going to reiterate that the -- that the prices would have to be non-discriminatory and transparent even if they weren't strictly based on cost of service. But you mentioned in there do you want to maximize revenues as one of the questions. And I -- and I would hope that the answer to that is not always no. Because if the overarching goal here, at least one of the important ones, is to grow the DER market. So you wouldn't want to set the prices -- well, maybe maximizing revenue would do that in some cases. See how I just came to that point?

MR. NACHMIAS: That was my point. Maximizing revenue doesn't mean maximizing price.

MS. REYNOLDS: Right.

MR. NACHMIAS: It means a fair price that people would then use this service.

MS. REYNOLDS: I was going to give one example of drawing a line between -- between what could be a platform service revenue that's value added and a competitive service. So because you mentioned that data analytics.

So we were -- you know, we've discussed it internally amongst our member companies and we're thinking that a good place to draw the line would be that because that is -- you have access to that data as a function of being a monopoly and you could provide that on the cost of service basis to DER providers. If you then did data -- and -- and analyze that data too, you know, not just the raw data.

If you then though are providing that directly to customers, that could -- that's a competitive service that a third party could offer so that in the near term that you'd be restricted from that particular market segment and be limited to the first example because that's something that can foster the DER market.

MR. NACHMIAS: Yeah, I guess it depends and this will evolve overtime, right. So it's not perfectly clear. But I think initially, right, there -- there's certainly data and information that we want to provide to customers so that they then are interested in engaging and managing their energy usage and engaging with third parties.

At what point, you know, might third parties -- you know, I think third parties would always be, you know,

once they get the sale and they're working with the customer would be able to do more. Maybe they take data that -- that, you know, the customer authorizes to be given to or sent to or sold to the third party and then the third party sort of packages that up in a new way where they're providing, you know, additional value to the customer.

So I think this is going to evolve, but I think what is clear is that the utilities have sort of a platform ability to help engage the third parties and -- and -- and customers. And what's what we ought to be doing.

MR. MAGER: I guess I just want to add. You know, we prefer a more cost-based approach for monopoly-type products and services. If -- if the Commissioner likes to go with a value-based pricing, I agree with the prior speakers that it needs to be transparent and -- and non-discriminatory.

The idea that -- you know, that -- that the utilities are going to provide a product or service based on their monopoly status using investments funded by customers and charge, you know, Company A 1,000 dollars, and Company B 2,000, to me, does not make sense and is inappropriate.

In terms of cost of service, I want to be clear that what we think of as cost to service would include a reasonable allocation of the utilities' employees, the -- the -- a reasonable allocation of the cost of the -- the

infrastructure, the DSP system needed to provide the service.

But you know, I guess, I still had -- I still think there's a slippery slope involved where you have the customers funding all of the utilities' investments, all of the equipment, all of the labor, all of the time, and it cost them 1,000 dollars to provide a service and the utility gets to decide whether it -- whether they charge, you know, the 1,000 dollars or, you know, 1,000 dollars plus some return or 2,000 or 3,000 or 4,000, especially when, at the end of the day, whatever they charge is going to be a cost borne by the customers who -- who funded the service being -- the utilities being in a position to provide that service.

I don't have a -- I don't have an issue with value-based pricing where it's a more competitive service that could be provided by other parties in the marketplace. But when it's a truly monopolistic service, I think there are pitfalls that -- that need to be avoided.

MR. NACHMIAS: I got to say I think we would agree with you that -- that -- that it ought to be done through the regulatory process and it ought to be transparent and we ought to set the prices based on some fair way to do that. And it could be that there's stakeholder input in that and different -- you know, different entities say this is what the value is and we have some sort of process and come up with what might be a value pricing.

So this is a new area for all of us. But and I -- I think I would agree with the go slow. I sort of -- I sort of chuckle at myself that I said to Anne do you really think that we're going to really go so fast. But you know, we ought to sort of go slow and have the right process with -- with the regulators and -- and all stakeholders having input.

MR. HENRY: Okay. We're running low on time. I just want to make sure we've got time for maybe one more question and then I'd like to give you folks an opportunity to make some closing remarks.

MR. MYERS: All right. I -- don't look away, Mike.

MR. MAGER: Please don't get in trouble here.

MR. MYERS: Yeah, don't get me in trouble.

I just -- I want to try to make this a specific question. I think we use the term platform in this proceeding really generally and broadly, and we need to get more precise about what we're talking about. I'd like to sort of build on a path that Anne was taking.

That is separate the DSP operational functions and all the things that individual utility DSPs might have to do and just think about platform markets in general, like Craigslist or Yelp or --. And one of the biggest problems in those markets -- one of the biggest

issues in those markets is called the chicken or the egg problem, getting it started.

And that's one of the things that REV's trying to do is -- is create or enable transactions that are not enabled under the current system. So it's not -- we think governments and utilities are going to come up with wonderful innovative products that people haven't thought of and -- and going to sell them. It's -- what do we, government and utilities, how can we enable the two-sided, multi-sided markets that are growing elsewhere in the economy to happen here.

And -- and, you know, if you think about how Craig started Craigslist or whether Yelp or Adobe, where they get their revenues, they don't get their revenues really from selling products. It's other people saying aha, I can make money, and other people saying oh, that's something I always wanted to get. And Google and Craig are just sitting in the middle raking a rent.

But in order for those to get going, the multi-sided market economics are very different from the ones, Mike, you and I are used to. And we're all very good about dividing a pot. But one thing that utilities and governments are not good at, at all, is growing pots. We aren't. You know, it takes entrepreneurs. It takes people taking risks. You know, it takes Craig starting with his

friends and neighbors and rock groups and finally building up to something that people are willing to pay for.

And subsidizing, that is non-cost pricing on one-sided market to grow network economies on the other side of the market. So my question finally for you is -- is there room for new testament in your -- your six commandments are definitely fundamental to the old testament.

And yeah, I do want to want to see -- so is there -- is there a way that you could see to yes, we might be able to enable this -- all these transactions that aren't currently happening, but to do it, we need to start with a group of monopolists that perhaps don't risk their money but maybe take a rake because the benefits are not being had but could be had if we only just get pass this chicken or the egg problem.

MR. MAGER: There was a lot -- a lot in there. Some I agreed with. Some I -- yeah, I'm having trouble focusing on -- on the actual question.

MR. NACHMIAS: Is there a new testament.

MR. MAGER: I will take that back and consider whether to supplement or revise my six commandments. I'm going to rest on the seventh day.

But I -- you know, all the examples -- all the examples you cited involved private investment and so we're -- we're -- so we're -- we're trying to figure out

what's the best way to take something that happened in the private sector where -- where the companies that are -- have provided the access and are reaping the benefits also spent all the money and took all the risk. And so now, we're trying to figure out what's the best way to apply it to, you know, PSC regulatory world.

And so it's -- you know, so now you have customers who are under certain proposals providing all the money and taking all the risk, yet all the decisions and some of the additional profits are going to go to the parties that are not taking any risks whatsoever. And so, you know, fundamentally, I think there is some difficulty there.

And so the question is how much -- how much money and how much flexibility should we accord a utility that's not willing to invest any of its own money. And that's -- it's a really challenging question.

You know, I -- I certainly feel safer when we're talking about monopolistic goods and services that only the utilities can provide.

I -- I confess I have a comfort level in cost-based ratemaking and cost-based pricing. And, you know, maybe -- maybe in the future, if this thing gets off the ground and we're able to learn from our experience, maybe at -- at some future time it would -- it would make sense to, you know, loosen the reins a little bit and try different

things.

But to come out of the gate changing everything, you know, and letting -- letting the DSP provider act more like a private entry that's funded by a totally separate captive body of customers is alarming to me.

I just -- I have concerns that a lot of money is going to spent to develop the capacity to provide certain goods and services and then if they are priced too high, the revenues wouldn't be there and the only ones who are going to lose out are going to be the customers who funded it from day one.

I hope that was responsive, but if not we could chat afterwards because I -- I might have lost some of the -- some of what you're getting at.

MR. HENRY: Well, thank you all very much for answering the questions. And now, as I said, I'd like to give the opportunity to, you know, if you've got one or two, you know, important takeaways that you want us all to consider before we depart from this discussion, now is your opportunity to -- to share those.

MR. MAGER: I'm going to give Peter back my time because I think if I say anything, I'll just be repetitive with what I've already said.

MR. ZSCHOKKE: So I know I get everybody excited by value-based pricing being able to negotiate and

extracting huge monopoly rents from third parties. However, utilities have been very clear and it's been very clear in this docket, we don't expect to get a lot of monopoly rents from third parties. Everybody is saying there's no -- they don't want to -- they'd prefer to get it as cheap as possible.

And every avenue we've said -- and every informal discussion or whatever, you get the same thing and even in comments before the PSC. And that's the utilities' concern. It's Mike's concern.

We're going to put money on the table to build something and it's going to take time for that something to develop into something that is financially capable of supporting itself, if ever.

And, you know, that's -- so from our perspective that's going to be a tough challenge for the utilities, the regulators, the third party providers, the customers, how we actually go forward doing that because the last thing we want is to be in a docket trying to get cost recovery with Mike and him saying that's the -- that's the REV market, they pay for that so the customer shouldn't pay for that.

That's not a good day for us. It's not a good day for the policy of the State of New York. And so that's something we have to all wrestle with and keep in mind

as we go forward. How are we going to make this work and how we're going to pay for it effectively across all customers, including those who get advantage by taking -- participating in the new market?

MR. NACHMIAS: We want to facilitate the future. We're making investments to do that. We need to do that regardless of REV because technologies are advancing and so things like AMI, things like developing the DSP, those technologies are advancing regardless.

How we can use those technologies to -- to benefit and work with third parties to benefit customers is what we're trying to do. And how would it be fair to try to collect revenues that recognize that value and benefit participating and non-participating customers, I think is what we're talking about and what we should be talking about.

MS. REYNOLDS: I like this part because it seems like a political debate. Makes me want to say lockbox or something like that. So our message was platform service revenues, yes. Other competitive services, no, not yet.

MR. UMOFF: Yeah, I think that's -- we'd generally agree with that. I think one thing we acknowledge -- acknowledge, I think is important to acknowledge is getting started here is going to be the hardest part. So we really think laying the good groundwork of developing a neutral platform should be the focus in the short term,

moving iteratively and cost-based revenues from monopolistic services and really just giving the competitive market a chance to develop here while keeping the big picture in mind which is robust DER market.

And I'll leave it at that.

MR. HENRY: Thank you all very much.

MR. OLMSTED: We'll take lunch until about 12:45.

(A luncheon recess was taken.)

MS. NEVILLE: Okay. Good afternoon, everyone. My name is Peggie Neville and I'll be moderating the Energy Efficiency Panel. And having been granted the much coveted after-lunch timeslot, we will try our best to give you a lively panel discussion and keep everyone engaged and awake.

So let me start off by introducing our panelists. We have Rich Sedano from the Regulatory Assistance Project, Tim Woolf -- not in the order that you sat -- so Tim Woolf from Synapse on behalf of the Clean Energy Organizations Collaborative, Gayl Pensabene from National Grid, John Zabliski from NYSEG-RG&E, and Matt McCaffree from Comverge.

So to start us off, I'd like to provide a very brief summary of what the Staff white paper included for an energy efficiency EIM. Staff's proposal attempted to

recognize the meaningful contribution that energy efficiency can and currently does contribute to peak megawatt savings through permanent load reductions.

The suite of clean energy programs operating in 2015 provided an estimated 425 megawatts of annual peak savings. Even though peak megawatt reduction was not a focus of the predecessor EEPS programs, this 425 megawatts includes approximately a 185 megawatts through the old energy efficiency programs known as EEPS.

The proposed EIM sought to recognize this contribution and establish that a minimum of 10 percent of an incremental megawatt target be achieved through energy efficiency. Upon review of the parties' comments and additional conversation amongst Staff, we developed a series of questions that you all saw on the notice for today's technical conference that expanded a little bit and opened up the conversation somewhat.

So our panelists here have reviewed the questions and we'll kind of operate our panel as I think many of the other ones have in walking through the questions that were posed in the notice. And then we will allow for plenty of time for audience participation with question from you all and hoping to have a little bit of a give-and-take and ongoing dialogue.

So with that, let's get started with the

first question. Will an EIM that rewards the achievement of a portion of any peak reduction target be beneficial or detrimental to the growth of third party energy efficiency markets and why? And how might an energy efficiency-based demand reduction EIM be improved?

So the way we're going to run this is I'm going to call upon Rich first to kind of offer some overarching comments and then we'll let the other panelist chime in and take it from there.

So Rich, go ahead.

MR. SEDANO: Thank you, Peggie, and good afternoon, everyone. Thanks for allowing us to be here.

Energy efficiency can be quite a bit more prevalent in New York. The scale can be significantly higher and -- and through the combined efforts of NYSERDA and utilities. And the question is how? And the earnings impact mechanisms is a way for the Commission to drive how that happens to exceed today's standards.

Now, if you want third party markets to be successful in energy efficiency, one important thing to think about is the use of -- of how you determine what the savings calculations are going to be.

Currently, we use net savings. We focus on the net attributable savings from utilities.

If we use gross savings, if we trade an

objective that thinks about how much we want to achieve from every means and hold the utilities accountable for gross savings, then what we begin to do is -- is create an opportunity for utilities, not only through their own programs, but through every way that they can facilitate and enable activities of others to accomplish savings.

So we can still have, of course, net attributable savings targets and even EIMs associated with them, but using gross opens up an opportunity for third party success to count for something and for the utilities to be rooting for that success in the process. So as some in the energy efficiency field, I think, subscribe to the idea that there are more savings if the community can combine together and say we all did it.

Now a demand reduction EIM could be applied to a customer class or a location of particular interest or value, and that's not a problem. Another point to think about here is the distinction between a single-year approach and a multi-year approach. And between a -- so thinking about that, cumulative approaches across multi-years allows for slow gestating -- longer gestating programs and market transformation to count.

So I think in -- in summary, I think what this question offers is the opportunity to open up some -- some new potentially controversial ideas to think about gross

savings, longer lived measurement tracks, and more -- more surgical EIMs that identify strategically where the state wants to see success.

And I'll stop there.

MS. NEVILLE: Great. Thank you, Rich.

Tim, you want to take this next?

MR. WOOLF: Sure.

MS. NEVILLE: And shall we call something up for you here?

MR. WOOLF: In just a minute.

MS. NEVILLE: Okay.

MR. WOOLF: So is this on? Can you hear me?

Okay. I'm going to start with opening statement because it's important to have some background for my -- my following comments. Clearly, energy efficiency EIMs are absolutely essential to achieve the Commission's goals. There's no question about that in my mind. And these -- sometimes they're called performance incentive mechanisms. Sometimes they are called shareholder incentives. They're used all over the country for this purpose. And there's a long history there we can -- we can learn from.

Now without question, the most important element in an EIM is the target, the goal that you want to achieve. It's extremely important because it gives the companies direction as to what the Commission's expecting and

is the basis for the financial incentive. It's absolutely essential.

Now, as you know the Commission, just this week, issued savings targets for NYSERDA and the utilities. Unfortunately, in our view, and I'm speaking mostly on behalf NRDC and PACE, but also the clean energy organizations in general.

The targets that came out of the order this week are woefully inadequate for the job. They're not going to achieve the goals that the Commission has set up for this whole process. Actually, my first slide helps to make this case, yes.

So I have on the slide energy savings as a percent of retail sales. It's a familiar metric we use to compare across different size states. And I show what's happened in Massachusetts over the past several years and Rhode Island. Then I compare that to New York. And New York is the lower line. You can see why we're concerned about these targets.

Now I mentioned Massachusetts and Rhode Island not just because they're leaders in the country and not just because I work there a lot, but also because National Grid serves those states. They serve all of Rhode Island and they also work in -- in New York. So there's no reason they can't do the same thing here.

So the reason that -- well, I'll add that these states are able to do this without REV, without complicated estimates of LMP plus D at the -- at the local level for every circuit, you know, without a DSIPs that might take a long time, without, you know, adding in additional benefits in terms of environmental benefits. They've done this with -- without all of that.

The way they have done it is through solid regulatory policies for many years. They've done it through earnings incentive mechanisms that have been, I think, very successful and they've been honed over the years as they learned lessons. There's also a lot of stakeholder input there. And the targets they set are very aggressive and that's how the utilities get there.

Now the Commission has been very clear that these targets are only part of the solution, and that it's undertaking many initiatives to help engage third party vendors and to get additional market forces to -- to do the rest of the job, and that this would be done at lower cost to customers.

Now, this is a laudable goal. I think this is great. There are many ways that third party vendors can help lower cost to customers. However, the pursuit of market solutions must be based on lessons learned from the past. And these lessons clearly demonstrate that there's limits to

how much the markets can do.

So in our view, what the Commission is doing here, they're taking a huge risk with this approach. It's essentially betting on market solutions to do half the job of securing the most important, the lowest cost resource available to New York. It's a bet that -- they're betting that it's going to be able to start doing it this year. That's a bet I would not take.

Now I have a lot more thoughts about market and their role in this whole process, but for the sake of time I'm going to hold off and -- and get to those as we get to the later questions.

MS. NEVILLE: Great. Thank you, Tim.

Gayl?

MS. PENSABENE: Hi. My name is Gayl Pensabene; I'm from National Grid. To the right of me is John Zabliski, from NYSEG-RG&E. And together, you know, we'll discuss EE from the utility perspective. We'll complement each other with our prospect -- with our area of expertise within EE

The new Clean Energy Advisory Council created by the Clean Energy Fund is tasked with developing recommendations for sustainable market for procuring energy efficiency as a demand reducing resource.

You know, specifically task two, develop

recommended approach, you know, for a sustainable market, for procuring energy efficiency, and this proposal -- proposal should consider, you know, the approach to support the establishment of energy efficiency standard.

You know, this encompasses both the use of energy efficiency programs to reduce demand and the creation of a sustainable market. We've received clear guidance from the CEF order that there needs to be collaboration. And you know, as the utilities, we look forward to that collaboration.

I think I'll address the second part of this two-part question as to how an EIM can be improved. An energy efficiency based demand reduction target should be simple, transparent, and easily measurable. You know, an assessment of an EIM through a formal framework which identifies potential performance categories and metrics, assesses the importance to REV and the value to the customer, determines whether the utility has control or influence, and then implements it as a programmatic or a broader based EIM, you know, could drive improvements towards achieving policy objectives that produce long-term benefits to the customers.

You know, we know there's significant differences in how EE is delivered and measured with respect to demand response, you know, what it is offered. And coordination is -- is the key to that process of achieving,

you know, peak reduction through EE And, you know, coordination can result in cost efficiencies, you know, across the board.

The market would likely respond accordingly, but in the short term, you know, our programs will have to go through a transition, you know, with the appropriate redesign supports REV goals. And you know, I was -- I led the budget and financial analysis of our current ETIP programs and that's what those programs are. They're transition programs.

So I think, you know, customer engagement can also play an important role in market growth. And it's really educating our customers, you know, about energy efficiency, demand response, and providing value added propositions to manage that energy.

So I think in -- you know, in summary, program design, coordination between EE and peak demand, a transition period is important and a framework to assess metrics or an EIM or score card.

MS. NEVILLE: Great. Thank you, Gayl.

Matt, would you like to add?

MR. MCCAFFREE: Sure. Is this on?

My name is Matt McCaffree. I'm with Comverge. Just to give you a little context, we're a DR provider and we focus on the mass market. We focus on residential and -- and small business. We're the largest

mass market DR provider, DR-EE provider in the country. Over the history of our company, we've -- we've installed over 6 million devices across the -- in the households and businesses of 1.8 million customers. And last year alone, we called -- if you look at individual devices, we called nearly 9.5 million events.

So we absolutely believe that -- that having a peak reduction aspect to the energy efficiency EIMs is critical and it's -- I would agree with what was said earlier that -- that identifying the objectives and the targets is -- is critical to achieving the objectives of -- of REV.

And for -- for us, I think that the main thing that I'd like to communicate is that -- that a one-size-fits-all approach for demand reduction or for the demand reduction portion of the energy efficiency EIM, that one-size-fits-all approach will not -- will not work. And it's important to distinguish what the objectives are of that demand reduction.

So if you have, you know, a behavioral DR approach on one end of the spectrum versus an event that you can call immediately, those are two -- those are two different kilowatts. They're achieving two different objectives. So it's important to identify how timing is a piece of this EIM and -- and how -- how that's calculated into the -- the returns, either to the third party or -- or

to the -- or to the utility.

And also along those lines, it's important to distinguish how the peak reductions are calculated within one event. Take, for example, you know, two different types of approaches. You have a 4-hour event and you have your first approach where you get, say, a 4-kilowatt reduction in the first hour, a 4-kilowatt reduction in the second hour, and then zero in the third hour and zero in the fourth hour. And then you have a second type of product that has a 2-kilowatt reduction for each one of those hours.

Now, if you average that out, if you just took an average peak reduction approach for that event, then they're both the same. It's 2 kilowatt hours. But there -- the first one, in my opinion, is a lot less valuable. It's less predictable. And you're going to have, you know, snapback potentially within -- with those last 2 hours or after the event, versus the second one which is much more predictable. It's much more level.

And I think it's a much more valuable resource to the system, whether you're using that for energy efficiency or for some sort of capacity type of product.

So -- so we think that that's a pretty critical detail to get right on this EIM.

MS. NEVILLE: Great. Thank you.

Okay. We're going to move ahead to the

second question posed, which were what are the benefits and detriments to including an EIM based megawatt hour savings alongside the proposed EIM related to 10 percent of peak reduction through energy efficiency? And can two EIMs targeting megawatts versus megawatt hours coexist in a productive manner.

So once again, we'll start off of Rich and then we'll maybe go to Matt next and come back down the table this way.

MR. SEDANO: Okay. This will be brief. Yes, they can co-exist. There are states that have both and there are -- the challenge for the program administrators is to manage a portfolio of earnings impact mechanisms. And if you asked them to manage peak and energy savings I believe they will do that. Since this -- especially since in New York there's plenty of room for more savings in both categories.

So I think what the EIMs will do is drive the performance of the program administrating utilities. And -- and to the extent that there are gross savings metrics, that will drive their approach to dealing with others, as well.

That's it.

MS. NEVILLE: Thank you, Rich.

Okay. Matt, go ahead.

MR. MCCAFFREE: I -- I would largely agree with what Rich said. I do think that they -- they can

coexist. And, you know, for us we see the demand response products that we have and approach that we have is foundational to energy efficiency, but with the incremental peak reduction savings that you get through energy efficiency it works the other way around too. There's -- there's a complementary role for both DR and EE

MS. NEVILLE: Great. Gayl, go ahead.

MS. PENSABENE: You know, they are significant -- as I had previously said, there are significant differences in how energy efficiency and peak reduction initiatives are measured, you know, how and when they are offered and delivered to our customers. And so, you know, one point is a realistic incremental peak reduction goal should be developed based on the use of a benefit cost.

The portfolio of energy efficiency measures that can be offered affect how much money the customer and the utility have available to impact peak reduction initiatives. For example, residential lighting programs are measured in terms of kWh. reductions over a broad timeframe and, you know, would be undermined with proposed energy efficiency term in -- in terms of peak load reductions.

Measures that would reduce peak may cause backsliding on kWh. and the state's carbon emission reduction goals unless additional funding is provided. You know, peak reduction is presently a small dollar value component of the

benefits, and the benefit cost of current programs.

And then, you know, EIMs must be carefully considered to ensure that they do not inadvertently shift emphasis from one goal to another. You know, and a careful balance will need to be struck between the twin goals of megawatt hours, savings, and peak demand reduction.

MS. NEVILLE: Tim, did you want to respond or react?

MR. WOOLF: Well, to say I agree with all the things that have been said. In the world of performance incentive mechanisms, there's a term called unintended consequences. And it refers to shining the spotlight and providing financial incentives on one area and not the others at the -- at the risk of the others. And I think if there were not an energy savings target, then you would have -- you would basically have the unintended consequences of sacrificing those goals for peak reduction.

But if I may, I'd like to use my next slide to -- to just make a simple point about how -- right there's fine -- how this doesn't have to be very difficult.

And again, I'm sort of drawing upon, at a general level, the EIMs that had been used in Massachusetts and Rhode Island for -- for many years now. They've evolved, but that's kind of where they've come out. And it's quite simple. You have your target and the target can be defined

as energy, could be defined as megawatts, peak demand. It can be defined as shared savings. It can be defined as all three of them.

And you want to start with the thresholds. So you don't want to give them money for very little work, but you want to have at some point they start to get an incentive when the savings become meaningful. Then you have your target and then you might want to have a cap at some point. And you want to have some kind of increasing financial incentive between the -- the threshold and the cap. It's fairly simple. And then you can have your incentive. That's the Y axis there. How much dollars do you provide?

And there's a lot of ways to do that, but what I found over the years is if you set it on the base -- basis of how much energy efficiency is spent, how much dollars is spent on it, then you've got a nice connection to the spending and the incentives so that the incentives are likely to get way out of whack with the spending in either way.

And so the concept here is that the ratepayers would be paying anywhere from 4 to maybe 10 percent more than they would otherwise, but in return they're going to get a whole lot more benefits from the program because the utility is pushing it just that much harder.

So I just throw this out there to make the

point that EIMs can be fairly simple and probably should be, and they should be thought through to make sure that we don't have this unintended consequence of one area of getting more attention than the other.

MS. NEVILLE: Thanks, Tim.

I just want to clarify for myself and perhaps others. When you referenced basing it on the dollar spent, you're talking about the financial incentive as a relation to the dollar spent on energy efficiency, not the -- the metric you're measuring is the money spent or did you mean the latter?

MR. WOOLF: So that's a good question. What I mean by that is if a utility, just pick one, Con Ed has 100-million-dollar energy efficiency program, then it would eligible for 6 million dollars as the incentive if they were to meet their target.

MS. NEVILLE: And the target is based on something other than the financial spent?

MR. WOOLF: Yes. Oh, yeah, the target is based -- that's key.

MS. NEVILLE: Right. That was what I wanted to make sure --

MR. WOOLF: That's very important.

MS. NEVILLE: -- that you weren't talking about spending.

MR. WOOLF: Targets based up on megawatts, megawatt hours, net savings, yeah.

MS. NEVILLE: Got you. Okay. Thank you.

Okay. Amanda, could you go back to our slides on questions?

We'll now turn to the third question which was how could an EIM be structured to reward or penalize the accuracy of energy efficiency savings claims?

Rich?

MR. SEDANO: I was interested in this question because I was trying to figure out at the beginning if it was a problem if -- if the utility achieved too much energy efficiency. I never really heard of that as being a problem.

What I would say is that in those places that have some sort of incentives for efficiency, you can either have a shared savings approach, which I don't tend to like because it puts a lot of pressure on the EM and V process, or you can have a threshold level that -- that where you earn a significantly -- a significant incentive over the target.

So remember we're -- we're talking about EIMs that are motivating behavior beyond the standard. We -- we might want to set the -- the target at some level above that, but we might want to set a series of targets for a series of steps of performance above that so that if -- if you're wrong

because you did a fabulous job, well, there might be some additional reward available for -- for being wrong that way.

Now if we're being wrong down, I think the current system has a penalty for that. And I think that that has to be used very judiciously. And so I'm a fan of dead bands around the target where, if there is some reasonable error around the target, either up or down, that there's no action taken, that -- that -- that the -- any penalty would be imposed if the deficiency were -- were big enough and that would -- that would define the size of your dead band.

But I think that programs can and should be managed so that the -- there is a full array of -- of positive and negative outcomes that the program administrator is seeing and that it has the full opportunity to -- to -- to achieve as high or as low as their corporate decisions motivate.

Hopefully, the EIMs will motivate -- in my view, hopefully, will motivate high achievement, but that there should be the full range of possibilities available.

MS. NEVILLE: Thanks.

I'll give Gayl a heads-up. I'm going to go to her first, but I just want to give a little bit more context to this particular question based on Rich's comments is that inherent and kind of a -- I think we're trying to get at what this question is there are some folks out there that

may be skeptical as to the realness of the energy efficiency savings and can they really be counted on as a DER out there in the field.

And so kind of what we're getting at there is -- is there an ability to look at accuracy of savings claims and kind of that's more of the context.

So Gayl, we'll let you go from there.

MS. PENSABENE: Okay. Thank you.

Well, two components of structuring an EIM to reward or penalize energy efficiency savings claims are really the ability to quantify and measure the energy and the demand impacts. You know, traditionally, energy efficiency programs have primarily been focused on reducing customer usage through kWh. and the installation of energy efficiency technologies.

The focus on energy efficiency impacts has really driven the evaluation priorities to emphasize, you know, estimating the kWh. savings that result from the programs.

You know, quantifying peak demand impacts have not been an EM and V. focus and, you know, there is additional challenges related to the availability, the cost of collecting and, you know, the application of estimating peak demand impacts, you know, in the energy efficiency programs. Demonstration projects will provide an

opportunity, you know, to test the market, to gather data information, learn, and adapt, you know, and construct positive programmatic incentives based on actual experience.

And -- and what I mean by this is that, you know, the information obtained from the demonstration projects will help to construct the incentives to really validate those energy efficiency savings.

MS. NEVILLE: Okay. Tim, do you want to go next?

MR. WOOLF: Sure. I don't see this topic of EM and V. as really being high enough priority for EIMs. Actually it's a very high priority, but we have, all across the country, a lot of experience with protocols for how to do EM and V. And the DOE is picking this up with the uniform methods project you're familiar with. So there's a lot that's already out there. And I think the utility can be held to those protocols without having to give them an EIM to do so.

And I would add, there's a -- there's a danger there and this is true with any performance incentive mechanism, you want to make sure that the benefits outweigh the costs. And, you know, if the utilities are given an incentive to improve accuracy, they may spend lots and lots of amount of money to get more accuracy when more accuracy isn't really needed or certainly isn't worth the additional

cost. So there's a -- there's a real danger there.

I do think that if the utilities intend -- start relying more and more on third party vendors, then we may need to think of a more comprehensive protocols and maybe more independent verification of those.

And so there may be, you know, innovative ways to cover this topic. I still don't think even there you need an EIM.

Finally, I'll make one point about penalties. I'm not a big fan of penalties for energy efficiency activities because it creates a very negative signal that can create ill will with the utilities. I think penalties are warranted in some places, but I think they should be reserved for places where there's like really gross mismanagement or imprudence because we want -- you know, we want this to be seen as in the utilities' interest and a part of their business plan. So they should be used with caution.

MS. NEVILLE: Thank you, Tim.

Matt?

MR. MCCAFFREE: I'm -- I'm largely going to agree with -- with what you just said, Tim. But the issue that I have -- that I have more often than not with -- with some evaluations on energy efficiency programs, especially in situations where there is a dead band, is -- you know, there's all this time and money, quite frankly, spent on, you

know, measuring with a micrometer when you're cutting with a chainsaw.

So I think that the opportunity here in New York is to look at ways that the evaluation process can actually innovate alongside these programs. There are great opportunities for -- for working alongside some of the program implementers, whether they're utilities or they're third parties like Comverge, to understand what kind of data they have.

So that would help -- A, it would help optimize the program, and B, it would help with a more timely evaluation because I think that that's really important. I think the timing of -- of these results is critical to, you know, set the -- set the future course for the utilities and for some of these programs.

MR. SEDANO: Peggie, could I say something?

As you would re-clarified the question, this is some -- the question that is sometimes asked in more blunt ways, is energy efficiency real. And sometimes from the point of view of looking at utilities what you see is capital plans that don't seem to change despite there being savings or forecasts that don't seem to change despite energy efficiency savings.

And I think that this is part of what underscores the interrelated parts of REV with the DSIP plans

and other elements of REV tying together. I think it's important to see feedback from energy efficiency savings in capital plans and in forecasts so that then you can see how energy efficiency is actually affecting future operations and, over -- over years, accumulating really distinctly different future.

So in addition to what has been said about -- about the evaluation process, which I agree with, I think there has to be this feedback where you can see what's happening. In a different context, ISO New England reports that the effects of energy efficiency and demand response, in their forward capacity market, has saved hundreds of millions of dollars of avoided transmission facilities.

And that's because they keep track of what was posted and then what is taken down because of the success of these -- these other -- other resources. I think we need to keep score like that so that we can affirmatively answer that question and address any doubts that people might have.

MS. NEVILLE: Great.

Okay. We will move along to question four. How could an EIM or score card metric be structured to support increased third party delivery of services through sustainable business models and how could this be measured?

So again, we'll start with Rich and then we'll go down at the end of the table and come back.

MR. SEDANO: So this restates something that we already discussed. I think that if we want third parties to have -- be motivated here, we need to think about gross savings targets for energy efficiency that encourages utilities to motivate others to achieve overall savings and makes utilities partners with third parties and -- and cheerleaders for them.

We can have targets for kilowatt hours and kilowatts, as we've talked about before. And I think it's also useful to think about the many different things that energy efficiency accomplishes.

This panel seems to be focused on EIMs just for energy efficiency. But when we think about the score card and the portfolio of EIMs that we're likely to have in New York, many of those are potentially going to be motivated by energy efficiency success, lower carbon, lower cost, lower line losses. So we might see EIMs that are promoting energy efficiency all across the array of portfolios. And -- and to that extent we will see support for efficiency throughout the EIM system, not just in those EIMs that are focused on energy efficiency.

MS. NEVILLE: Great. Thank you, Rich.

Matt, go ahead.

MR. MCCAFFREE: You know, I'm going to go back to my -- to my point about timing. And I'm -- you know,

I've long been an advocate for energy efficiency and the -- the overall benefits that it provides, system-wide benefits, the economic benefits. And it's great to have energy efficiency programs that just reduce overall usage.

But when we're thinking about the world that -- that REV is trying to proactively address with -- with more intermittent resources, with more distributed resources, I think that the timing of those savings is -- is very important. And incorporating that into some sort of score card metric for the program implementers will be very useful, not just in the immediate term, but as more of these resources come online. I think it's going to provide an overall system wide benefit.

MS. NEVILLE: Okay. Great.

Gayl?

MS. PENSABENE: Yeah. And -- and we -- we agree with that. We think the metric should begin as a score card metric and then, after work and experience, turn it into an EIM. You know, we talk about the -- the formal framework, you know, assessment of an EIM or score card metric through a formal network, you know, which identifies the potential performance categories and metrics, assesses the importance to REV, you know, the value to the customer, and determines whether the utility has control or not.

You know, we're currently creating third

party -- opportunities with third party contractors and vendors to deliver EE to our customers.

You know, in the order that just came out, you know, we're still digesting that, but we certainly look forward to, you know, working to continue those partnerships with third party -- with our third party vendors through the design of our programs.

And I think at this point, we just don't have enough information or indication as to, you know, how the markets will respond with changes in program design to really, you know, increase the third party delivery of services to design EIM, you know, around energy efficiency.

MS. NEVILLE: Okay. Tim, go ahead.

MR. WOOLF: I agree with the score card approach on this one. Score cards are great. They're very low cost -- very low risk way of getting the information we need to know how the utility is performing. Whether we move into an EIM really would depend upon what the score cards show overtime.

But I want to use this opportunity to -- to elaborate upon the point I made earlier about the limitations of third party delivery services for energy efficiency.

It's really important to recognize, we've learned this over 30 years now, energy efficiency is not a simple commodity. It's not like going down to the store and

buying a banana, going to Amazon and buying a computer. It's much different and it's so multi-faceted.

And one of the terms that's been coined is that energy efficiency suffers from market barriers, that the market barriers prevent customers from adopting energy efficiency. These market barriers have been widely recognized and studied, again, for 30 years. They're called market barriers for a reason. They make it very difficult for the customers to buy and for the markets to sell efficiency products, even though those products can have significant value to the customer and even more value to the utility.

I'm sure most of you are familiar with these market barriers. They include things like limited information, limited access to capital, limited access to the products themselves, split incentives between landlords and renters, very short-term perspectives. You know, customers are thinking about that the bill for this month or next month or maybe next year, when the utility is planning out for the next 20 or 30 years.

Now, there's certainly room for third party vendors and for market forces in delivering energy efficiency. There's no question. However, it's critical that the Commission understand what's the proper role of the utilities versus the role of the markets. I would argue

there's three critical roles for the utilities.

One is program planning. Markets don't do a good job at planning. That's not what they're asked to do. Market forces each -- each vendor works for their own interests. Energy efficiency is something that a utility needs to monitor and to plan for and implement for its own purposes, as well. So it has to plan these things out.

Program design is the second element that's critical, to make sure that all customers are served and all measures are offered and that state energy policy goals are achieved. Markets don't really care about state energy policy goals unless they're somehow included in the prices.

And then finally the funding, the funding is absolutely essential. I know there's a lot of talk about getting the markets to somehow bring forward funding. It's great to pursue those and I think we should and I think that looking at, you know, third party funders is great. You know, also on bill financing, there's a whole world of information about that now across the country. That's all great. But we can't count on that happening in the next couple of years. That has to be something that's -- that's sort of developed over time.

So in this construct where the utility's doing the planning, the program design, the funding, the utilities have the ultimate responsibility to meet the energy

savings targets. And then they could be deployed with -- they can use third party vendors to help achieve those targets. They can go out -- and they do this all the time -- and have competitive bidding processes and hire vendors to come up with innovative ideas to actually get the job done. But it's the utility that does that planning.

So if the utility establishes a sound EIM for energy efficiency with strong energy efficiency -- I mean, energy savings and megawatt savings goals and even net savings goals, then they have the incentive to take full advantage of the competitive market to do this at lowest cost. So it's already built into the construct that I suggested earlier.

Also, it's important to keep in mind this critical principle behind any incentive mechanism is that the benefits have to outweigh the costs. And here I am not convinced that paying the utilities additional funding to find ways to pull in third party vendors is going to be worth the cost that it's going to incur to customer. So I suggest that we be very cautious about that.

There's no reason we couldn't have score cards to do it, to get the information and to see how the utility is doing, but once you put money on the table, suddenly there's a great, much greater risk for -- for customers.

MS. NEVILLE: Great. Thanks, Tim.

Okay. So we'll move to the last question now. And before I read off the question, I just -- little bit of context that oftentimes energy efficiency programs are talked about on a dollar-per-megawatt-hour basis. And so what this question was really trying to get around is traditional energy efficiency programs are usually authorized with a budget and a target and so you can calculate for every dollar spent how many megawatt hours are you authorized to go get.

This question is trying to look at is there a way to structure an EIM to reward performance and improvement in dollar-per-megawatt hour which may mean you achieve the megawatt hour target you then establish for less money or it may mean you get more for the same amount of money.

And so I'll turn to Rich first and then we'll go from Tim back down the row.

MR. SEDANO: Well, I think the experience around the United States, as applied to this question, is that the answer is no to this question. The total cost of energy, the cost of energy per megawatt hour saved is a useful statistic. And I think every Commission wants to know the answer to that question in their states.

But it's important to be very clear about what that statistic means. A low price could mean that there

was a terrifically efficient way of delivering programs or there could be a cream skimming sort of ham-handed approach to programs that did -- did not take advantage of opportunities in projects, in homes, and businesses, and left a lot of important savings on the table.

That would have been very economical to get, but, because it required a few more steps or a few more dollars, were left hanging. So this is -- a corollary to this is whether it's important to have a very high benefit cost ratio or one that's closer to one. If you have a very high benefit cost ratio, that means a lot of economical energy efficiency again is being left on the table. It seems like that's something that you would want, but, in fact, having a benefit cost ratio closer to one indicates that you're achieving this -- the all cost effective energy efficiency that suggests that you're -- you're benefiting customers.

So generally, an approach that attaches some sort of reward or valuation to this number, especially just as the number without any reasoning behind it, is a bad idea.

MS. NEVILLE: Tim?

MR. WOOLF: I wholeheartedly agree. I think, in a word, cream skimming is a huge risk. I want to use my third slide to -- to make this point as clear as I can. This slide, the color doesn't show up much, but it shows basically

a supply curve of energy efficiency programs. And this is based upon actual data from, it turns out, a Massachusetts utility. And on the Y axis, you have the levelized cost of saved energy in cents per kilowatt hour. And on the X axis, you have all the different programs that the utility was running and you can see many of them are 2 -- 3 cents a kilowatt hour. Those are mostly the C. and I. programs and then they start to get more expensive. The more residential programs get more expensive and then you've got low-income programs that are at the top.

So you can see how there's a wide variety -- wide range of costs for serving customers. Now, which ones are the market going to go for? Pretty obvious which ones they're going to go for. And if you have -- even the utilities, if you give them a dollar-per-megawatt-hour incentive, they're going to do the same thing. They're going to go for the low-cost measures.

Now, this gets even worst because for each of these programs, you could create a similar curve for just the measures alone. So look at the commercial and industrial one which only costs 2 cents on average. Within that, there's also a whole range -- a whole slope of measures that go up to the avoided cost that could be adopted. And if you have this kind of a metric, you're going to have the utilities themselves and certainly the market doing just the lowest

cost measures. So it's a -- it's a huge problem.

And I'll add this slide also shows why reliance on market forces is very dangerous. Literally, this is like the equivalent of a supply and demand curve from micro-economics. The supply curve shows the -- is the energy efficiency bars going up. The demand curve, you can think of as the avoided costs. And those are the horizontal lines across the -- and what I've done is I've shown, you know, avoided LMP -- avoided LMP plus transmission then plus distribution, and then plus distribution plus E is the environmental benefits.

If you're going to -- let's just say -- and the Commission has said this. They -- they will value energy efficiency at that full avoided cost. And I have a number here, 20, just -- it's just an arbitrary number to make the point.

The supply curve and the demand curve meet at 20 cents a kilowatt hour. So if it was a single commodity with a single market for energy efficiency, you'd be paying 20 cents a kilowatt hour for every kilowatt hour saved there, even ones that cost 2 cents.

And then if you -- what you could do with -- and this is getting a whole lot closer to where this might work is, say, okay, we're going to have a market just for C. and I. and let that -- let that and we're going to have a cap

or whatever it is, 2 cents. Well you have the same problem there because and you're going to have cream skimming and all the things that cost more than two cents, the measures that cost more than that for C. and I. won't get served either.

It's a very difficult problem. And it's not something that's easily solved by market forces just going in and people looking for the lowest cost option. It's something that's been achieved over time by the utilities having the incentive to go deep and to serve every customer, to avoid lost opportunities and to make sure they get all the savings they can when they visit a facility.

MS. NEVILLE: Okay. Gayl?

MS. ZIBELMAN: Can I just have a follow-up?

Tim, has there been a study on what -- the underlying fundamentals of the cost? I mean it's one thing to note that costs are higher, but do we know what drives the differential?

MR. WOOLF: Oh sure. The costs are shown on this curve.

MS. ZIBELMAN: Yeah.

MR. WOOLF: So in general, there's a variety of products that are offered and there's also different customer types. The obvious difference is commercial customers are easy to reach, whereas residential customers, there's many, many more. So just the reaching them, the

marketing, the delivery, just the face time that -- the time it takes to drive to their house costs a lot of money.

And also when you reach a big facility, there's just more energy savings available. So there's -- you know, you could dig into all the annual reports and the studies that have been done by utilities to show that, yes, it just costs a different amount to serve different customers.

And then some products might be just retrofitting a home or a building. That cost something very different than a new product that just has a small incremental cost to make it efficient.

And then you have another market, which is new construction, where it's just sort of a different way to try to get energy efficiency. And that has different costs which are directed more at the architects and the engineers.

So it's just not a simple product. It's a multitude of products and that's why it's not a simple commodity.

MR. SEDANO: It also depends on how you deliver it. Different delivery systems are going to deliver the same measures in different profiles. And different markets are going to benefit from one delivery system or another.

There's a lot of talk now about going to what

they call mid-market programs, the home stores, and focusing energy efficiency dollars on -- on the retailers in an effort to get more hits.

So there's a lot of different ways. There's not one -- there's not just one supply curve. The supply curve is dependent on the program design and the market that you're in. And I guess the key thing here is that program evaluation is really the answer to the question that you're talking about here. It -- you can't reduce it to a dollar per kilowatt hour saved, but you can evaluate whether the programs are successful based on what they say they're going to do and what they did.

MS. ZIBELMAN: So does that suggest, in thinking about EIMs, that we should be thinking about the market segment and thinking about, you know, wanting to drive down the cost of acquisition?

MR. SEDANO: Yes.

MS. ZIBELMAN: That the focus ought to be, you know, some segments may not need a lot of attention because they're easy to access and the market will likely to go there?

MR. SEDANO: So I have a story.

MS. ZIBELMAN: Others -- the others were the regular -- where the utility can play an important role as a DSP

MR. SEDANO: There was a state that had a simple kilowatt hour incentive for their utility programs. And all of the corner store type places where the Commissioners went to shop said why don't I ever get any energy efficiency. And they looked into it. And basically what was happening was the cost for residential acquisition actually wasn't that bad and industrial acquisition was really easy because they were not that many of them. But they could never get a hold of the person who is running the drycleaner or the corner store. And so that was a terrible challenge.

And so basically every June, the utility looked at their program and they said well, we're not going to do that, we're going to move all the money to the other classes. And the commercial class was getting very little savings. And so what they did was they changed their reward system, to reward commercial savings. And all of a sudden, they worked harder and they did better.

MR. WOOLF: But I will add -- it gets back to my point earlier about planning. One of the key things about planning I didn't mention is customer equity. It's absolutely essential that the utility think through how are customers being served by this product.

We talked about affordability earlier this morning. Affordability can mean lower bills. And if people

are served by this, then they can -- they will have lower bills. So yes, you might want to especially correct for sort of asymmetries in incentives utilities have and how easy it is, but you want to make sure that all customers are being served relatively fairly.

And so what often is done is, in the plans themselves, the budgets and the savings are agreed to by the stakeholders and the Commission. And those are used then to set the EIM and the utility has to -- has to meet those.

MS. NEVILLE: Great. Thank you.

Turning to -- John, go ahead.

MR. ZABLISKI: Well, and I'll let Gayl make -- but I just wanted to add one clarification point.

And Rich, you were talking about, you know, the cost of the program and then also the benefit cost that's run, you know, to -- to show that the program is worthwhile. And currently, at least under the old EEPS portfolio formula, and at least for now going forward under the ETIPs, and until the new benefit cost handwork is in place, the dollar-per-megawatt-hour cost of the program is per megawatt hour of first-year savings. And the cost of the -- of the measures that are used in the benefit cost calculations are the dollars per megawatt hour of lifetime savings.

And so right now, we are running programs. We have two different forces driving us. So in order for the

program to be run at all, it has to have a positive benefit cost, you know, based on the cost of the program per lifetime savings of the various measures that make up the benefits in HVAC program or a boiler-and-furnace program that may be 20 -- 25 years.

But when it comes to day-to-day running the program and trying to hit the targets that we currently have, because we all currently have targets for, you know, what we're supposed to make for the -- for the program for the year, and you look at shifting budget money from program to program where it will do the most good, you're -- you're looking at that dollar per megawatt hour of first-year savings. And so that may have an entirely different consequence than looking at the lifetime savings that you did for the benefit cost.

And so end result is you may end up promoting things that would not necessarily be something that would be in the long-term lifetime interest of efficiency and sustainability and so forth. But in order to hit this year's budget and metric target, and the way the units are, you know, you end up going with faucet aerators or, you know, screw-in CFLs or some other thing that -- you know, that hits that budget metrics.

So I just wanted to -- to mention that, that currently we have those two different and sometimes competing

metrics in the system that we're working with now.

MS. NEVILLE: Thanks, John, for adding.

And I think that the -- in energy efficiency land, the tracking of both lifetime and first year is -- is an important aspect. And you point out some kind of differences that we have right now between tests and targets that have been, but I think from a perspective of the measure mix, which I think is really at the heart of what you're talking about, if our law -- if our goals are really more long-term objectives, lifetime metrics become perhaps something that make get more prevalence than perhaps in the past.

Matt?

MR. MCCAFFREE: You know, I won't rehash what's already been said. I'm -- I'm in agreement with -- with just about everything.

Just one point that I would like to make though is, you know, a dollar-per-kilowatt-hour type of goal or measurement is -- I think that there are -- there's a more nuanced way to incentivize energy efficiency, especially within -- within REV where one of the objectives is -- is to spur innovation.

That's it.

MS. NEVILLE: Okay.

MR. ZABLISKI: And could I add one more?

MS. NEVILLE: Yes, please.

MR. ZABLISKI: I'll just add one more thing, talking about demand reduction, which is, you know, proven to be a valuable resource and very well documented. But in the earlier question about competing goals for megawatt hour goals versus megawatt peak reduction goals. The current system that we have right now and, in fact, the order that we received a week ago today, we're given fixed budgets. We're also given megawatt hour targets, but the fixed budget is more important.

And so right now to do these things, we have a constraint of -- of how much money we're allowed to spend. And so what that means is, if you look at energy efficiency and you say okay, in addition to the megawatt hour target we also want to add a megawatt peak reduction target, which maybe a very worthwhile thing, what we would have to do is -- is adjust the money that we're spending to get the megawatt hour target to also drive the peak reduction.

And so, you know, we kind of have those two competing things. And what that means is -- because the technology is actually different. So one of things that we're seeing in efficiency programs right now and one of the utilities actually filed this for street lighting is LED exterior lighting. And it's a wonderful application. The ones that they've done outside the building that I work in

are fantastic.

But there is zero peak reduction from LED exterior lighting. But we wouldn't want to give that up as an energy efficiency measure because the market wants it, you know, the incentives can help to put more of it in. It's -- it's a great long-term measure that really, you know, reduce -- saves energy, reduces carbon and so forth. But yet, if we were under a capped budget to institute a peak reduction metric, then we would probably -- that would be one of the first things that we would look at cutting would be the exterior lighting.

So I just wanted to also make the point that under a fixed budget, you know, it ends up being tradeoffs between the two.

MS. NEVILLE: Thank you.

Okay. We did start this panel a little bit late and I know there's interest in moving to the last panel, but we do want to allow for opportunity for the audience to ask questions, both here in Albany and then I believe we have a couple of sites phoned in.

So we'll start with the room here, if you want to move up to the mic.

MR. LEONARD: Hi. My name is Ron Leonard and I should not sit as close I am to microphones because I stand up too easily and ask questions.

One of the things that I've had public discussions with Audrey about is big data. And I don't know if we've really dealt in enough to how that really affects how good this type of program would be.

And the other thing that I'd like to put out for a point of discussion is sort of Richard Kaufmann's mantra that, you know, market indicators lead by example. If we really want to see improvement in reduction of waste, should we not start looking at the intrinsic system, itself?

You know, if we take FERC's data, for example, and says that if we look at a BTU of energy, turn that BTU of energy into electricity, move that electricity through the wires, getting all the way down to the consumer, we only get 20 percent of that energy turned into deliverable electricity. That's a horribly inefficient system. Richard also points out the capacity factor that we have which is generically horrible.

Should we not be leading by example, pushing more things like DG as the solution to the equation? Where should we be spending our intellectual energy and also our capital?

MS. NEVILLE: Okay. Thank you.

So to summarize, there were two points there. The first, big data, and then the second piece about more overall system efficiencies and how did it handle that and in

the context of the energy efficiency panel, I -- I guess I would defer to --.

MR. SEDANO: I mean, Matt started talking about the big data aspects to it. I think that all of the states that have deployed AMI have started thinking about using the data that's being created for that in their energy efficiency programs.

Matt, you might want to say more about that.

MR. MCCAFFREE: Yeah. And I do think that -- and I came at this kind of from an evaluation standpoint, but -- but I think the bigger theme is that with -- with the -- this evolution of big data and big data analysis program, you can -- you can optimize programs and you can rapidly deploy changes to those programs.

And it's not just the AMI data that utilities are using and that companies like Comverge are using, but also because of the penetration of broadband, you know, roughly three out of -- three out of four houses here in -- in New York have access to broadband. And that's another -- that's another data stream, especially when you have some sort of device in the home, like -- like we do with thermostats or with switches or -- or what have you, as long as they're Wi-Fi enabled.

So, you know, I think that there are -- yes, there are lots of opportunities to use that -- that data to

even make this process better.

MR. SEDANO: But I -- I would say, in addition to that, though, that the interpretation of the data is important. And that's one reason why I like those states that have energy efficiency collaboratives because there are a lot of interpretations for this data.

To some degree, this data is new and having experts from different points of view to talk about what it means and how you might change it can -- can be a good investment.

I don't know if anybody else wants to talk about the data side before we talk about the other part?

MS. NEVILLE: Any other takers on data?

Okay. John?

MR. ZABLISKI: I guess I would just say that we are moving in that direction and certainly big data would be helpful. But I -- I would agree that the analysis is -- is also very important.

And you know, we're doing a program evaluation right now where we're doing a billing analysis and, you know, we have roughly 50,000 customers, 2 years of consumption data in the pool that our evaluators is working with. And, you know, I had asked the question casually, well, if we add AMI data for these customers, would it make a difference in doing, you know, the statistical analysis and

then regressions and so forth.

And the feedback that I got, you know, and this is -- DNVGL is the company doing this -- was that well, you know, it might help a little bit but, you know, at this point we have such a volume of customers and we have a number of years of monthly read data, and so, you know, we're -- we're -- you know, it may make a little refinement, but at this point for the particular work that we're doing, it's not critical.

So we are moving in that direction, you know, with specific programs and projects but, you know, we're also trying to make the best and I hope doing a good job with what we already have at hand.

MS. NEVILLE: Great. I'll give anyone on the panel an opportunity to take on the second piece before we move to the next question.

MR. WOOLF: Briefly I'll just add that yes, there are opportunities to increase efficiency at the end use relative to generation and transmission and distribution. And this has actually been the goal of many efficiency programs over the years.

Sometimes it takes the form of field switching to natural gas, which has its own issues, political issues and institutional issues. But there's also other opportunities. There's, you know, heat pumps, space heating,

water heating heat pumps that can help that. So that should be a part of the overall goal. And that should be something that utilities should seek out as a part of their looking for all cost effective efficiency opportunities. That should absolutely be one of them.

MR. SEDANO: And I think the enhanced distribution planning that is, I think, somewhere down the road in the REV process is going to help the utilities figure out exactly how to do that.

MR. WOOLF: Yes.

MS. NEVILLE: Great. Thank you.

Next question here in Albany?

MR. FLINT: Hi. Adam Flint, New York Energy Democracy Alliance.

This is getting to be a pattern, Ron.

I really appreciated the comments about cream skimming earlier. I had about 3 years that I served time doing Green Jobs Green New York outreach in Upstate New York, trying to do energy efficiency work.

And a few of things that I think are relevant here, one is in terms of the data question. We're all over the map when we do our work there. There are folks who are on Twitter and there are folks who are not connected at all. And so though the averages may show a high percentage of connectivity to broadband, when you get up in my neck of the

woods and many other places upstate, that will have to be taken into account.

But I -- I think the larger point that I learned from that experience and what we're doing currently is that there needs to be mechanisms that allow experiences on the ground to be incorporated into policy in a little bit more real time than we're seeing.

This is not an energy efficiency point, but the point I made earlier about the commercial industrial market upstate, we've been having an issue for -- for quite some time. I'm hoping with efficiency, the lessons learned could be fed back a little bit quicker.

Now of course, you might legitimately ask what in the heck does this have to do with EIMs and utilities. And I don't have an answer for that question. But I think it would be good to have incentives for the key parties to be connecting a little bit more effectively on the ground with people who are working in different contexts around the state on energy efficiency on the residential side as perhaps a partial solution to the issue that was raised earlier, i.e., it's harder to reach those folks, harder connect.

Final point, I totally agree about the challenges of reaching small commercial enterprises, and that they need some special assistance. There need to be special

motivations there. They are the worst of both worlds. They are small like residential and they are more overwhelmed.

So thank you.

MS. NEVILLE: Great. Thank you.

I will ask if we have any questions from any of the satellite locations over the phone? No? I hear there is a delay but --.

Okay. Then we'll ask if there is any other questions here in Albany?

All right. Well, I'd like to take an opportunity to thank all of our panelists for the discussion. And I will, I think, turn it over Peter to see what's next.

MR. OLMSTED: All right. We're going to -- we're going to move right in here to the next panel, but while people are shuffling around and getting organized, we'll just take a -- take a quick pause here.

(Off the record)

MR. PADULA: Let me start by saying good afternoon and thank you for staying around for the long haul. This is the panel on Standby Rates. It's a extremely important subject to the Commission and I look forward to all the interaction among the parties and the panel itself.

Let me introduce myself. My name is Marco Padula. I'm the Deputy -- Acting Deputy Director of Market Structure in the Office of Markets and Innovation. Most of

my 20-year career has been in rate engineering. I have an engineering and MBA background. So I'm very excited about talking about standby rates today.

We actually have a extremely broad perspective of panelists today. I just want to introduce them. We have Rich Sedano from the Regulatory Assistance Project.

Just raise your hand so everybody can see.

Bill Atzl from Con Ed, Mark Marini from NYSEG-RG&E, Tom Bourgeois from Pace Energy and Climate Center, Bob Loughney from New York City and REBNY, and I would note we also have Jonathan Flaherty, who is on the phone, also from the Real Estate Board of New York, which we called REBNY. And on the end of the panel is Doug Staker from Demand Energy. So a broad perspective from the utility, the customer, academic, research, and I think -- I think we have lot of bases covered.

In preparing for the panel, I reviewed the panel's comment summaries. I asked each of them, hey, give me your -- some bullets on exactly what you're going to say so I could come up with some questions.

And I also looked at some past documents that the Commission has issued regarding standby rates. And I just want to take a moment and read a paragraph from a Commission document that I -- that I came across. Quote, in

the conferences held from time to time, from the present and prospective users of breakdown service, the general opinions seem to be that the charge was prohibitive in most cases and that few could afford to take this service at such a figure. As the Edison company insisted that it was reasonable, an attempt was made in the investigation to secure sufficient evidence to determine the facts, but it was found that sufficient data were not available. The companies submitted certain calculations to support the rates charged, but they were so vague and indefinite that they were most unsatisfactory. The rates have been fixed, more or less, arbitrarily without a knowledge of the exact facts and of the various elements which determine the costs.

So I thought that one of the panelists submitted these -- these comments to me. It turns out this is from a Commission order from 1908, 108 years ago.

MR. SEDANO: No joy in Mudville.

MR. PADULA: Breakdown service in New York City. So 100 years later, we are still talking about the topic. Just a little history there.

So I really hope, from my perspective, is to have an open discussion today of the issues and perhaps arrive at specific solutions, as Sonia Agarwal suggested at yesterday's opening panel.

So I want to provide just an overview of

Staff's recommendation in the Track Two white paper. We noted in the white paper that the Commission recently expanded the current exemption from standby rates for a period of 4 years, with the intention that an improved rate design would be implemented that will eliminate the need for further standby rate reform.

We recommended that the methodology for allocating costs that determine the contract demand and as-used demand components of standby rates should be reviewed in this new context, in conjunction with the method for calculating LMP plus D, which is described later in that -- in our proposal, as well.

For immediate purposes, we recommended that a reliability credit should be instituted, similar to what has been put in place in Con Edison. And we had a series of recommend -- recommendations to expand the revisions to the Con Edison offset tariff, expand and revise the Con Edison offset tariff.

In our notice for this technical conference, we had a series of questions that you're all familiar with and they covered three different areas. It's really understanding the current rate design. In my experience, you could talk to three different people about standby rates and each of them has a different understanding of exactly how the standby rates work and exactly how they're designed. So I

really hope that this discussion will kind of clarify some of that.

The second area that the questions cover are what changes or approaches could be made to the existing allocation methodologies, cost allocation methodologies. And what processes should we use to get to those changes. We're very interested in -- in knowing from the parties what process should we now move forward with to make these changes. We realize it can't be done overnight or it can't be done in one meeting or two meetings, but tell us what kind of process you believe we need, moving forward.

With that, I'm going to move to the panel remarks and we'll start with Rich Sedano, who's going to provide a brief overview and set the context of our discussions for today.

MR. SEDANO: Thank you, Marco. Thanks for inviting me again.

And New York is, I think, on a forefront of trying to correct this 100-year-old problem that the Department of Energy is trying to work on with their industrial energy efficiency and CHP efforts and C-action process.

And in REV, I think if there is -- there's a few animating words in REV and one of them that I write down in capital letters on papers when I'm making notes about REV,

a lot, is value.

REV is about identifying value, monetizing value, activating decision-makers and market actors to do things that would actually create -- that secure the value that is there. The value is there. The question is that we're wasting it a lot of times.

So to secure this value, to affirmatively focus on finding value and distributed resources, as REV declares its intent to do, through the Commission's words, and CHP, of course, being a very important distributed resource and important resource sitting in many industrial customers' buildings.

And validating customer choices for any resources that the customers choose to bring to the grid, which I think is another important thing about REV is, is motivating customers to not assume what we can't do, but to consider what we can do, and to expect that the grid will enable those things to happen if all the economics work out.

And including aggregated forms of customer activity like the campus setting and to charge customers for grid-based costs. So the value works both ways. Customers produce value for the grid, customers ask for service from the grid, and should pay for that based on its value.

And that -- that basically is -- is how the standby service and all the other elements to it, the buyback

rates, the maintenance, all of the other relationships that CHP customers are going to have with their utility, I think, are considered in the REV context.

And so I'll leave it there and let the others go.

MR. PADULA: Thank you, Rich. Much appreciated.

Now, we're going to move to the utility perspective and Bill Atzl is going to be speaking -- for both or you're going to have -- or will each of you have a --?

MR. ATZL: We'll each -- yeah, we'll each do some speaking.

MR. PADULA: Thank you.

MR. ATZL: So, thank you, Marco.

We've -- you know, we've also taken a look at the -- the elements of standby rate design as they were established originally by the Commission, and find that many of these elements still apply. For instance, delivery cost should be recovered through a combination of customer, contract demand, and as-used daily demand charges.

And the cost-based standby rate should provide neither a barrier, nor an unwarranted incentive to customers contemplating the installation of DG Standby rates are based on a revenue-neutral rate design for each service class. So that is standby rates are designed to produce the

same amount of revenue as conventional rates for an entire class of customers.

This is a source of confusion sometimes with customers and others regarding standby rates. Revenue-neutral is on a class basis and once a customer installs DG and goes on standby, their usage and their bill will obviously go down. So it's not revenue-neutral on a per-customer basis.

The current standby rate design reflects the diversity of DG through the use of both contract and as-used demand charges. And also non-monetized environmental values should not be reflected in standby delivery rates, but should be reflected in -- elsewhere in a payment that a customer may receive for benefits provided by their DG

So although the joint utilities believe that these elements of standby rate design are still valid today, we are open to a re-examination of the allocation between contract demand cost and as-used demand cost, but we favor doing that through a performance-based element.

So getting to the questions that were posed in the notice establishing this technical conference. As Marco mentioned the initial question was really background on -- on how standby rates work today. And we just want to give you a quick refresher on that. So under the Commission's standby rate guidelines, the cost of local facilities or

those that are closest to the customer are recovered from customers through contract demand charges. And those are assessed on the customer's maximum potential demand.

Under normal design conditions, those local facilities must have the capacity to serve the standby customer regardless of when the customer's DG unit might fail.

Now, at the other end of the spectrum are shared facility costs. Those are costs recovered through as-used demand charges. And at that other end of the spectrum, the most obvious example is the transmission system. And to the extent that not all DG customers need standby service at the same time, the cost of capacity in that portion of the system can be shared.

For the utilities other than RG&E, a standby rate matrix allocates costs between contract and as-used demand charges. The way it works is that we take the revenue requirement for a class of customers, for instance, let's say large commercial customers, and identify the costs associated with the 4 major components of the T and D system. So that's secondary distribution, primary distribution, substation, and transmission costs.

The standby matrix then identifies the portion of each of these cost components that will be recovered through contract and as-used demand charges. And

these allocations differ based on the voltage level at which the customer takes service.

So, for example, a secondary voltage customer has cost of the secondary system considered mainly local and more heavily weighted toward contract demand charges. And then as we get further, electrically, from the customer, for instance, into the substation and transmission systems, that allocation shifts more to the as-used component.

So it's important also to note here that a standby rate customer is not paying a contract demand charge for their full load through the entire electric system. That's another source of confusion that we sometimes encounter. They're paying a contract demand charge solely for the local facilities or the facilities that are closest to the customer. And that use of a combination of contract and as-used demand charges does recognize the potential diversity among DG customers.

So that's generally the standby approach for the utilities other than Rochester Gas and Electric. And Mark Marini is going to give us a description of how it's done at Rochester Gas and Electric.

MR. MARINI: Thanks, Bill.

So at Rochester, the results of a marginal cost analysis are used to set the standby rate components of contract demand, as-used demand, as well as the customer

charge. This marginal cost analysis measures up -- measures these components of the delivery system and they match up fairly well with the components laid out for -- for the standby rates or the standby rate components.

The first is customer related cost which are the meter the customer -- the services the customer related expenses associated with serving a customer. These costs vary with the number of customers on the system. So ideally, they're collected on a per customer basis. And those costs are used to determine the customer related component of the standby rate.

The second component that's measured through the analysis are design, demand related cost. And those are costs associated with local distribution facilities, which include transformers, local primary lines, and secondary lines. These are facilities that sized based on the expected maximum loads of customers using -- using them over the life of the equipment. And absent any changes in the customer's design demand, those are not expanded in response to month-to-month or year-to-year variations in actual usage.

So the optimal way to recover these costs would be through a fixed charge applied to some measure of design demand. And these costs, therefore, are used to determine the contract demand component of standby rates.

The last component of the marginal cost

analysis measures load related distribution costs which include distribution substations, trunk line feeder cost, upstream line costs, and substation costs, as well as marginal transmission costs. These are more extensively shared facilities. They are higher voltage components of the system that are expanded as peak load grows.

The optimal recovery of such costs would be in a per-kW-of-peak-load basis. And these costs then are used to determine the as-used component of standby rates. So once those marginal costs are developed and estimated and measured for each service class for each of those components, they are marked up to achieve the full delivery revenue requirement for the class which is another standby rate principle.

So although the standby rate methodology at RG&E is different than the other utilities, the principles are the same. A cost analysis is used to determine the responsibility between local or contract and as-used shared facilities. Only costs associated with local facilities are used in the determination of contract demand which recognizes the individual customers more direct cost responsibility, while costs associated with shared facilities are used to determine as-used demand which recognizes the variability and diversity among all customers.

So as stated above by Bill, standby customers

are not paying a contract demand charge on an entire load and a combination of shared and as-used recognizes the load diversity amongst standby customers.

MR. ATZL: So we'll quickly move on to question number two that was posed by the Commission. And that question is regarding how those costs, contract and as-used, could be reallocated. We would point out that any revised methodology to establish those charges should still be based on the underlying cost structure of the individual utility.

Now it is well-known for people who have been involved in standby rates that the standby rate matrix for each utility was a result of a negotiated agreement that occurred in each utility standby rate proceeding several years ago. And those settlements resulted in cost allocations between contract and as-used demand charges that were agreed to by a variety of parties with widely divergent views and ultimately found reasonable by the Commission.

So when we're considering reallocating costs between contract demand and as-used charges, we have to keep our eye on certain things. One is that, although certain customers' bills would be reduced by that reallocation, other standby customers' bills would increase. And that's something that we shouldn't lose sight of. It's not necessarily something that is good for all customers.

We also recommend continuing to use a standby rate matrix, but altering the allocation of costs by recognizing the performance of the customers' DG unit.

So, for example, Con Edison recently implemented a standby performance credit mechanism that provides customers with an opportunity to earn credits toward their contract demand charges based on the performance of their generating facilities. And this program was the result of a series of meetings among Con Edison, its standby customers, and other stakeholders to explore issues and concerns regarding standby rates.

During those meetings, one of the main issues put forth by the standby customers was that they believe that the then current standby rates didn't adequately encourage consistent DG performance and didn't compensate DG customers for the benefits that they bring to the utility system.

So the Con Edison standby performance credit mechanism was developed to recognize that, and to provide customers with an incentive for DG performance that would reduce their contract demand charges. So the mechanism allows a customer with demonstrated DG performance to reduce their contract demand charges and in so -- in doing so, it does change the allocation of contract and as-used demand costs.

And it's also consistent with REV goals for

system reliability and resiliency. Because REV -- REV is meant to use customer-sited DER as a substitute for utility infrastructure. And if we're going to do that, we need to make sure that that customer-sited DER performs. So this type of mechanism gives customers an incentive to really perform and make sure that their DG unit is providing what it was intended to provide.

This is also consistent with the reliability concept -- the reliability credit concept proposed by Staff in the Track Two white paper. Similar, but this proposal that Con Edison uses relies on measured DG performance. And we think that's a very important element of it.

Additionally, any standby performance credits must be fully recoverable by the utility from its delivery service customers.

The question three in the notice pertains to other methods of allocating besides what we have today in terms of a matrix. Mark Marini's description of the RG&E method offers one alternative, but we believe that the introduction of a performance element to the standby rate based on meter DG performance will better achieve the goals of REV.

And this has been successful for several DG customers in Con Edison service territory in the first summer of the new performance credit and we expect that to grow in

the coming years.

In terms of process, standby rates are highly utility specific in terms of utility cost structures and -- and their customers. And we think that most of the -- the changes that might occur in terms of the allocation of cost should be discussed in utility rate proceedings.

MR. MARINI: Thanks, Marco. And we're ready to turn it over to the next speaker.

MR. PADULA: Thank you.

Next up is Tom Bourgeois from PACE.

MR. BOURGEOIS: Yes, thank you, Marco.

I'm going to approach this from principles, too, but not -- not at the level of the design of the current standby, but maybe a much more generalized level. And I'd like to talk about fairness, transparency, alignment with state policy objectives, extracting maximum value from distributed energy resources, and also fully accounting for benefits to the system as well as the cost.

With regard to the first item, there's implicit evidence that the current standby rates are more burdensome than the otherwise applicable tariff. And I say this because, for years, certain customers meeting a megawatt size and an efficiency threshold have had a choice to opt into the standby rate or to stay with the otherwise applicable rate. And in overwhelming numbers, customers who

could have elected the standby rate have not done so. So I think that says something about the standby rate.

We had a technical conference last year and at that time we heard from several parties and commercial developers and others talking about how sizing -- in some instances, sizing decisions were not being made for efficiency reasons or not being made for economic reasons, but they are being made to stay below the level at which the standby was imposed, to stay below the 15 percent level.

So once again, I don't think we're getting the right result if -- if that's how business decisions are being made, not for efficiency, not for economics, but to avoid imposition of the standby rate.

Now in terms of transparency, the standby rate is not at all transparent. We've heard, over and over from end users and from developers and you mentioned yourself, Marco, that, you know, you get three people in a room and you ask how does it work, you get three or four different answers.

So with so many people finding the application of the rate very confusing and a rate -- I would suggest that a rate that is so confusing needs reconfiguration. I think we need a rate that's much more understandable. If you have developers and end users not really understanding how this operates having to pay a lot of

money for consultants to figure out what the imposition is going to be, that does not make for good forward decision-making and for good investment decisions.

Next, in terms of alignment with state policy objectives, New York has embarked on a bold plan reform, the utility business model and practices to plan for and integrate distributed energy from third party providers as a central focus to try to create vibrant markets for distributed energy resources on the distribution system.

And I would suggest that the economic incentives of the standby rate, as currently constructed, might be at odds with these objectives. So you talked about what kinds of modeling do we need. I think when we do model this, we look -- we ought to look at how is this -- how is any new reconfiguration of standby rates in line with or consistent with our state policy objectives for encouraging distributed energy resources.

And in terms of a firm empirical foundation, I think Bob is going to speak a little bit to this. I was not as involved in the case as others. But I remember the case in which this new empirical foundation was set. And we don't really have a firm empirical basis for the standby charges, I would suggest. I would question how valid are the underpinnings.

We heard about this allocation and Bill and

Marco were saying it was agreed to by parties. It was agreed to, but it was not based on any empirical analysis. It wasn't based on any system studies. It was more of a -- of an assignment of -- of dedicated cost versus shared cost that was arrived at in a multi-party arrangement. So I think we do have to take a hard look at the empirical basis of -- of this.

And we do have -- CHP systems have been operating on standby rates for many years. So I would suggest one thing that we could do is we could do an empirical study of how standby customers have interacted with the grid, and the cost and the benefits that they have provided. So we -- I would suggest that we establish a more firm analytical underpinning for the current standby rates.

In terms of extracting maximum value, I think we need a careful analysis of how standby rates, again as I said, impact the state's objectives. If we want to encourage high efficiency and clean CHP and other distributed energy resources to be operating in the locations of highest value and operating at the right time of the day and right season of the year, to improve grid productivity and lower system cost, I think we have to take a look at how the standby rate or any alteration of that would -- would affect those decisions and, ultimately, affect the -- the uptake or the amount of -- of DERs that we see on the system.

Finally, I would suggest that we -- you know, we've looked at this in terms of the standby rate and the imposition of cost and how costs need to be recovered. On the flipside, we know that distributed energy resources create significant benefits. And unless and until -- significant and I would also say at this time uncompensated value. There's a lot of uncompensated value created by distributed energy resources.

Until we feel confident that we're compensating for the value, I think we have to take a look at the net of the benefits and the cost in any -- any alteration of the rates.

And finally, I would point to a recent development as just as a point of caution. Hallets Point, Durst is building a large new complex which is not going to be interconnected with Con Edison. There's been a lot of issue there about standby rates and the impact that standby rates have had on some of their other developments. And I would suggest that this is a lose-lose.

The customer loses value, the value of the grid. And on the other side of the coin, the grid loses the potential benefits the properly designed and configured and operated DERs could have. So we don't want to see more of this. We want to see a lot less of this.

We want to have -- see a rate design that

encourages customers to stay on the grid. We don't want to see customers to be migrating off the grid. And I would suggest that's in the interest of the utilities as well, because with innovation, with new product development, with the declining costs, I think more customers may be able to do this. And we want to -- we want to see the best outcome for both customers and utility system.

MR. PADULA: Thanks, Tom. Very interesting perspective.

Let's move to Bob Loughney, representing New York City and REBNY.

MR. LOUGHNEY: Thank you, Marco.

I've been fighting these standby wars so long, I sometimes feel like 100 old and it's been 100 years we've been doing this; right? And Marco, you've been here too, so --.

Anyway I wanted to start out by commenting on the current rate design and how it's been developed. And Bill referred to this, but -- and Tom did also. There's this thing that came of a 2001 case that was called the standby rate matrix. And it sets percentages as to how much is local -- how much is allocated as local, how much is allocated as -- to the as-used.

So the problem is that the rate matrix was the result of a settlement in a very, very contested

contentious case. And the -- the underpinning -- the underlying assumptions as to the rate matrix which is then used -- and I'm not blaming the utilities, this is what they have to do. They have to follow the rate matrix. But the assumptions have never been tested and it's more than time that we have to revisit whether the assumptions are correct.

For example, for the Con Edison system for primary voltage customers, 75 percent of the primary distribution system and 50 percent of substation costs are deemed to be local. Now, that's -- that seems a little dubious to me. But I guess, beyond just, you know, throwing a number out and saying it's wrong, at a minimum, I think the numbers have to be examined in an analytical way.

The -- you know, the fact that we have a problem is illustrated by the fact that the Commission actually stepped in and granted a standby rate exemption -- expanded the standby rate exemption. So the fact that the standby rates may be off, I think the Commission is already there in terms of their thinking by creating a standby rate exemption that allows a lot of people to avoid the standby rate if they want to.

As Tom said, when people have been afforded that opportunity on the Con Ed system, 94 percent have said I won't take the standby rate, I'll stay on the standard rate.

The other thing about standby rates, they're

never really analyzed in the -- separately in a cost study in a rate case. So we collectively have no idea whether the cost of serving standby customers is more or less than the rates -- with the revenues that are giving, whether they are more or less than the cost that they're imposing. That's unusual. We do that for every other service class.

Standby rates have -- Tom mentioned the standby rates have driven customers to get off the system, the Durst petition. The Commission actually cited to the Durst petition in its order, allow expanding the exemptions because they noted that people leaving the system is something that has to be considered and it's -- and it's a reason actually they used to justify granting the exemption of the -- expansion of the exemption that they did.

I think we've already talked about expanding exemption. I mean, the Commission has already taken steps. The performance credit is another positive step. I think these interim steps are welcome, but they don't really solve the problem, which is we have to get in and take a look at what the standby rates are and what the basis of them is.

I -- there are some examples that 2014 REBNY provided specific examples of what it would cost a customer on standby versus if they were on the standard rate. For customers with -- there was up to a million-dollar penalty, if you want to use that word, if you went with the standby

rate versus the standard rate for some of them.

The interesting thing is the penalty is worse for the customers who performed better. So this -- because of the contract demand and the way it's imposed, the better you perform the bigger the penalty is for you for being on the standby charge.

The second and third questions, I kind of lump them together in terms of how should the allocations of cost be modified. And I think -- you know, again, I think we have to start with the proposition that the current rates are not defensible. And one way to do this -- one way to proceed is to suspend the standby rates until we get to a point where we have confidence in them. And this has never -- I don't think we've ever had that kind of an examination.

To some extent, the expansion of the exemption provides that relief for new customers. It doesn't do much of anything for existing customers. So one thing to consider is whether the standby rate should be suspended until we -- we complete an analysis of what the right rate design is.

Tom mentioned that the standby rates have to be looked at in terms of whether they're consistent with state policy. REV is advocating for increased reliance on DERs and improper standby rates have been identified as a barrier.

I think any analysis of new standby rates has to include a cost-of-service analysis that recognizes the non-coincident nature of the standby loads. I know that the utilities seem to think that the use of a contract and as-used charges somehow recognizes that. It does recognize it, but we don't know whether it's being recognized in a proper way.

Bottom line is that, in my view, the standby rate matrix should be thrown away. And the cost allocation should be following -- proven cost causation principles that are applied to all other classes and not unproven assumptions of what local facilities are and shared facilities are.

And I guess, you know, the rationale for having a contract demand also, I think, needs to be re-examined. The utilities design rates for all the other classes without contract demands, they have the ability to do rate design, demand reactions for the classes have been eliminated. They use actual demands to design the rates and I think that's where we ought to be looking to go.

Finally, the contract demands the penalty for good performance. You pay the same contract demand if you are not interrupted for 11 months, if you -- as you do for the month you were interrupted. So regardless of how well you perform, the contract demand is there every month. And we hear about it from all the customers that the contract

demand and the level of a contract demand and the unavoidability of it is really the problem with the standby rates.

I guess, just to the last question, Marco, the how should we proceed, I think, you know, one way is to suspend the standby rate tariff until the need for standby rate is verified, that the -- that the basis of the rates can be tied to cost causation, and a determination that the new rates are consistent with REV policies. If they're not suspended, I think, the interim relief should remain in place until there's an expedited process that provides new cost-based standby rates and -- and they're in place.

In any event, I think, the thing I'd like to emphasize is that the regulatory uncertainty surrounding standby rates is very bad for DG projects. Even something like the 4-year stay out or the option to get out of standby rates for 4 years, it's difficult to make investments when you don't know what's going to happen at the end of the 4 years. So the much preferable way would be to -- to get this issue on the table and get it resolved so that, going forward, investors can make decisions and -- and be confident that they made the right decisions.

If I could, Marco, I just want to tee it up a little bit for --

MR. PADULA: Sure, please.

MR. LOUGHNEY: -- Jonathan on the phone because Jonathan is from REBNY. I've worked with him and he -- I think he was going to provide some examples of -- of how this actually affects the analysis of projects.

MR. PADULA: So we will move to the phone now. And Jonathan, I hope you can hear us and --.

MR. JONATHAN: I can hear you guys just fine. Can you hear me?

MR. PADULA: Perfect, yes. Go ahead.

MR. JONATHAN: Great. Well, wonderful. Thank you very much for inviting me to share some thoughts on this.

I thought I would -- I would -- it would be most helpful for me to just respond to a couple comments that were made by Tony and Bob. I mean, Marco, you know, we have provided what we believe would be reasonable solutions to the standby issues to you and to the Commission through REBNY and directly to Con Ed. And the response from Con Ed is all of our ideas are not feasible for various reasons.

So I don't think it will be helpful to go over those reasons now on the phone. They've been submitted in letters and as testimony. So I thought I'd just address a couple of the comments that were made in regard to how that has actually affected us who are trying to build these projects.

So first of all, I wanted to just address a comment that Bob made about 4-year exemption. I mean, I can tell you that that was the -- as you very well know, Marco and Bob and others, that was the outcome of a very long process of discussions about standby rates in the Con Ed territory and looking at the various projects that actual developers were doing in real numbers.

And I want to be clear that we thought that that was -- I mean, that was wonderful. Thank you for that exemption. But I can tell you that that actually ended up causing a significant more amount of heartburn within the company about the numbers.

Because when we put together an economic analysis and need to go spend 8 -- 10 -- 12 million dollars to build a facility like this, to just know at the end of 4 years something could happen is not really, you know, spreadsheetable. And it makes it very, very difficult for people to make financial decisions that they think would be reasonable and prudent. And so in fact the 4-year exemption not only didn't help, but it was a major detriment to our decision to move forward on cogen, which we have not, because we just couldn't model what happens after that.

And I mean, I hate to say the regulatory uncertainly equals not investing in capital, but these are very expensive projects and you need all the years in the

model to reflect what's actually going to happen. And if we just have after 4 years, well, maybe we'll go back to standby, this might happen, that might happen, that's just not an acceptable level of risk for an investment that can be many millions of dollars.

So that was not a bad decision by any stretch. It unfortunately was actually a negative in our economic analysis of moving forward on cogen.

I would also add and I'm here representing REBNY, but I will also just add as a personal note from -- from the company I work for, Tishman Speyer. We've looked at putting in cogen facilities at every single property we own in New York City, which is a decent number. And we can't get the economics to work on any of them. So -- and again, Marco, you know the details of all of that, but we really have looked in, you know, exquisite detail as to how to make this work.

We were very motivated to try. And we, at the moment, cannot make a pencil out. But I thought, with that in mind I would just -- there's couple of a comments to Tom and Bob had made.

One was Tom had mentioned earlier about sizing inefficiency versus economics. And I just wanted to say that that was an enormous piece of the puzzle when we looked at this. We were purposefully sizing our facilities

to be under the thresholds for triggering the automatic reclassification and we were not basing it on efficiency. So we were putting in -- or we're remodeling to put in, you know, facilities that were definitely not nearly as efficient as they could have been because the economics of -- of passing the standby threshold was just not an area that we wanted to go down at all. And we modeled that, but it just looked very unappealing.

The second one was a rate that's understandable. I mean, I can tell you that we, at Tishman Speyer, in the business of doing complicated financial modeling, we've probably got some of the best Excel modelers out there in the whole world in our office, and we could not accurately model this over and over and over.

And we had to bring in many consultants to take a look at this. And I would just add, and I don't mean to pick on Con Ed, but Con Ed made a point of every time we had the model, they would pick it over, pour over our model which was, you know, hundreds of megabytes, zillions of tabs, and tell us where everything was wrong. But they would never provide a Excel spreadsheet that actually they said would accurately model the standby rates to their satisfaction. They only wanted to look at ours and tell us why it was wrong.

And look, I -- again, I think, we're pretty

good modelers. We could not accurately model this at any building, no matter how hard we tried, according to Con Ed. It was always wrong. So I think we're pretty good. If we can't model it, I question how anybody can model it accurately.

And then, the last thing I would say about that is that, you know, construction cost in a lot of these models, one of the things that we spend -- again, that last year showing the Commission and Marco and his team was that, you know, real world examples, real construction costs, and in the down -- especially in New York City construction costs in existing buildings, and that's where you're really going to find the most opportunity for DG, they're just very, very expensive.

I mean, if we want to put in a cogen in any of our buildings, it's going to have to come in, in pieces, and it's going to be quite pricey. And so what we found was a lot of the assumptions that were being made about what was reasonable and what was not were not using accurate construction cost estimates. And so when we came in the real numbers, you know, the payback went through the roof because the numbers that were being used by others to model were just not realistic in the downstate region.

So we found that we couldn't get a payback below 7 to 8 years on any possible way of sizing, economics,

et cetera, at any building, no matter what the case was.

And then the last comment I would just make, which I know, Marco, you know very well also is something that we care greatly about, but -- and I know this isn't the purpose of today's conversation. But we would just throw out there that it is 100 percent uneconomic to put in a cogen facility at any facility that is served in the Con Ed service territory. It cannot be done economically. And that standby tariffs are an integral part of this conversation in areas where available. So with that, those are all my comments.

Thank you for having me.

MR. PADULA: Thank you, Jonathan. Much appreciated.

And now we'll turn it to Doug Staker.

MR. STAKER: Well, thank you for the opportunity.

MR. PADULA: Give us a customer perspective.

MR. STAKER: I appreciate that. We build distributed energy storage systems. We actually started working with Glenwood in Manhattan about 5 years ago. And the first system we put in, we had -- we had done a business model basically on a standard rate, looking at the ability to do a couple of things. On the supply side, to be able to move to day-ahead hourly pricing, which, at that point in

time, many people thought we were just crazy, fundamentally.

As we went through the interconnection application, Con Ed told us, look, we're going to have to move you on standby because you've exceeded the 15-percent threshold. So when we first looked at that, we just thought that our project economics were just -- just not there. But we didn't know any better, so we dug in deeply.

And you know, I would make the argument that if you really dig into Con Ed's standby rate, we can show, especially if you look SE 9, rate 1 to rate 4, just moving in an account over to -- from that rate off of the standard rate, you can save money.

And it's a little more complex when you look at some of the larger commercial rates, the rate 2s to rate 5, rate 3 to rate 5. Just the act of moving doesn't save money. And the fact is -- I don't know if it's just the remnant of the design, but when you look at moving from a rate 1 to rate 4, there's really not a large energy component.

And so what we've noticed is certain loads, it's not all loads, that tend to have a high load factor, high energy factor, when you move that energy element out a bit and you move strictly over to a power element, be it fixed or as-used, that just that act changes the way that -- the rate to apply it. And we went through and we understand

the mac charges, the simplification on mac that's been applied just make life a lot easier the way mac was applied before was very complex.

Now it isn't always true and I think to what J.P. was saying, what Bob was saying, on a lot of the commercial accounts that we look at, it is punitive to go there, but then we're trying to leverage some other elements about standby.

We're the only heretics in the room here that we like standby from a couple of different reasons. One is that it allows us to move to a daily rate. Just from the standpoint that if tomorrow, we want to stop and pause our operation, which is basically around demand charge reduction, and participate in a DR operation which is total -- in total conflict with -- with demand charge reduction, we can do that with only a day's penalty for demand charge reduction, the day's penalty being the loss of the as-used charge. So we like that flexibility.

The other thing is it's measured from 8 a.m. to 10 p.m. So it means, for many of us, at our age in this room, the term nights and weekends are free has a little bit of history, but that has some operational benefits, as well, especially in the storage business where you may want to charge up at night, where you won't be penalized for an as-used or demand charge overnight when you're going to charge.

We think that standby is a half-step to the types of rates that we need to be thinking about, looking down the road from a REV perspective, where we have proven to Glenwood that moving today had hourly pricing on the supply side is beneficial to the point that they moved their entire fleet over to that.

And again, many people looked at them and -- and said why would you take that risk. You know, lots of people like budget certainty, like to know flat rates, all that, but that's a market driven force out there and we have been able to leverage market pricing, off-peak pricing versus peak pricing, and put that to an advantage and drive savings from end user perspective.

When we get into the argument about fixed versus as-used, at the end of the day we have to have a grid out there to connect to even in the future of REV. You just -- you need it from a variety of different reasons. So there should be a way to recover some of the fixed cost in a fixed fashion. I think that gives Con Ed the revenue certainty they need. It also lets us know that that grid's going to be there, should we need it.

And -- but I have an argument with my friends at Con Ed about the value of that fixed and that I don't think fixed should be a higher portion. I think there's more variable cost out there, which has always been an issue when

a lot of distribution companies will say, look, our capital costs are fixed, we don't have any variable or marginal costs.

And when you look at a couple of things that -- that drive losses in the system, fatigue in the system, if you look at what that correlates with, that correlates with load. So if you look at the way that we measure line loss, a lot of line loss is measured -- they will sum up the energy over a period of what was generated and then they'll look at the energy that was delivered over that same period and they'll look at that differential. And that's a common way of looking at line loss.

The reality is line loss varies with -- with load. It's a function of the amperage squared. So if you look at the differential on July 19th, 2013, the load in Con Ed, excluding Westchester, the peak was -- I think it was a little over 11 or -- yeah, a little over 11.7 gigawatts -- trough was about 7 gigawatts that morning. The ratio of peak to trough was 1.4 to 1.

When you look at -- but the effect of line loss at peak versus the trough, you got to look at it from a squared function, which means line loss at peak was 2 times what it was at the trough. So when you look at the elements of line loss and the time variability throughout load in the day, there are marginal cost that occur as far as from a line

loss perspective.

And when you measure an average line loss in the summer about 9 percent in the service territory, well that's an average number. So if you looked at it in real time, is it higher at peak, lower at trough? Absolutely. But nobody really studies and looks at it that way.

So my point is there are marginal costs out there through the operating. And that rolls into the as-used. And -- and getting to the point where we've had discussions with Richard Kaufmann about hey market-based pricing to drive behavior. And our argument's been with the way that they implemented the DMP incentive for storage is it's great incentive for covering the cost, capital cost of installation, but it does nothing. It did nothing to solve any of the demand charge reduction we were looking for in the summer months during that rate structure.

But if you can take that and build that into a function where prices were variable in the different districts within Con Ed -- because in the Con Ed networks there are different peaking times in downtown, midtown, Upper East Side, Brooklyn-Queens, varies throughout the day. And if you put price elements around that, in those areas you would reduce some of those marginal costs and you could put a structure.

We think you should take the next step and

develop not only as-used by as-used hourlies through the same operating windows where they are priced by the hour for capacity, and they are priced higher for the 4 peak hours that that occurs in the system peak which, in downtown that's typically from 11 to 3, midtown 2 to 6, lower east side that's about 4 to 8, and then the residential areas it's from 7 to 11 p.m.

And I would just close on thinking about looking down the future. And we have all these distributed resources out there feeding into the grid. A solar project feeding into the grid at noon in Brooklyn-Queens adds minimal value than if you could have that energy used to shape air-conditioning load from 7 to 11 at night. So there's -- even though there are marginal prices for taking that energy in, we really have higher value if we could change and shape that load later in the day. And so when we look at overall marginal cost and -- and new designs in rate structures, we ought to take that into consideration because that brings not only distribution system benefits, but also societal and -- and larger grid benefits in the whole.

MR. PADULA: Doug, thank you for that different perspective. And I expect to probe that a little bit more with the other members of the panel as we move along.

Before I get into my questions, I want to

have Rich just come around again and give us some overlying comments that he's been thinking about as he's been listening to the panelists and then I'll throw some questions out there for the panel.

MR. SEDANO: Marco, thank you.

And I had several things I wanted to say, and Doug, you touched on many of them more fine grained use of demand charge timeframes down towards daily. I hadn't really thought about hourly but I think if -- if that works, more seasonal approaches to applying demand charges. I think there is -- implicit in what you said are potentially unbundling some of the -- the charges included in the demand charges between transmission and distribution.

Again, in the interest of providing the customer with some opportunity to control with actions that a customer can take, what their ultimate bill looks like, I think that's part -- a significant part of all of this is that the customers have opportunities to exert control, but they don't take them because if the tariff doesn't give them that chance, then they won't bother.

I appreciate and endorse what Bill said about how performance should matter and the tariff should certainly motivate CHP customers to perform to their highest.

One thing that's important in all of this perhaps is the -- is the critical importance of information.

The opportunity to share information between customers and utility, especially as you get into these more value-based approaches to try to identify value becomes a very important. And I -- I am also sensitive to the concern that the tariff be simple. Many of the suggestions that -- that -- that people have to improve standby rates don't necessarily simplify them unless we can use automation to smooth out some of those -- those confusions. But the -- the kind of outcome where -- where customers don't understand the rates certainly is a signal that there's a problem.

And I also appreciate the -- and one point I was going to make that motivating customers to take demand response actions through -- through elements that allow for interruptible service is important. So in the end -- and perhaps it's important in a standby rate 2.0 to think about where standby rate 3.0 or 4.0 is going is that ultimately there should be some convergence with the generation that's coming from any customer that's generating anything.

That standby rate solar, whatever they're generating, there should be -- start to become some convergence the principles that -- that you're going to be charged based on the value of the service that you use and you're going to be compensated based on the services that you're providing energy capacity and ancillary services.

That's it.

MR. PADULA: Thank you, Rich.

And I actually share that -- that last point wholeheartedly that, you know, in the last so many years we've been talking about standby rates as a standalone rate, separate from all other rates, but as we move toward our REV vision with much more proliferation of distributed resources, the rates really just become one.

We really have to think about it. I -- I think about it in my head as what is the value of the grid to customers with DER, and what is the value of DER to the grid. And if we try to keep those two things in mind, I think that will help us as we move forward, both here in the standby rate process that we're envisioning moving forward and also LMP plus D process that started. They really all come to the same point sometime in the future.

Well, I heard a lot about that matrix or matrices. I actually brought a copy of all the matrices, Con Ed, Central Hudson, NYSEG, Orange and Rockland, and all the utilities. And every single one has different percentages in it. So it's true. There's no consistency.

And there's reason for that. I was involved in some of those discussions back in the early 2000s. It involved sitting in a room, bringing in utility engineers, and basically, asking them, hey, if you add a new customer at this location how do you look at that load as it is put upon

other -- other parts of the system? Do you look beyond the substation? Do you look beyond the transformer? Do you look -- how does that impact transmission?

So with that perspective, I just want to ask the utility folks and then open it up to others, do you think we -- we have more system -- more system information today or should we require gathering of more system information that would enable us to do a more accurate determination of the impact of customer loads on the various components of the system that would help us get a more accurate cost allocation of cost to a contract demand, to an as-used demand?

You know, keeping the same structure of the standby rate, but do you think we have more accurate data today? Do we need more accurate data to do that? I just open that up to the utilities and then others to -- to -- to respond to.

MR. ATZL: So we've given this a lot of thought, Marco, going back to the original standby matrix. And as you may recall after the 2009 Con Edison rate case, we had a standby rate collaborative where we reviewed again the standby rate matrix. And it was a similar process to what you described.

We had -- we had our engineers discuss how they treat the system and how they -- how they view customers in terms of building the system to accept the customers'

load. And if you recall, the -- the original standby matrix for Con Ed that was submitted had higher levels of contract demand in the -- in the more local parts of the system, in the secondary and in the primary, because our engineers billed to accommodate that load through the secondary and primary systems. And it was through the settlement process that -- that we came to the -- to the matrix that we have today.

But another element of it is that in -- for any individual customer -- there's -- there's always a set of the specific circumstances, but in -- in the ratemaking itself we have to try and accomplish something that can be implemented on a little bit more generalized basis. And that's where the -- the matrix concept kind of rolls together that the views of -- of engineers and other parties in terms of how these costs can be allocated.

But another thing to consider is that there's also a lot of discussion about benefits that the DG customers bring to the system. And our view on that is that you have your rates for electric delivery service and then benefits that DG brings to the system would be compensated separately through the DSP And I think that's consistent with the Track Two white paper from Staff, as well.

So I think we have to look at it more in terms of the service for purely electric delivery and concern

ourselves with the benefits on the other side in discussions about the DSP and the value of D.

I don't know if you want to add to that, Mark?

MR. MARINI: You know, as far as whether there's more granular -- granular data available, I think we have to be careful. I mean, there's probably a level you can go down to, but I'm sure there's an associated cost with that that may or may not be beneficial to get a result that somebody may not like any better than what's there today.

I don't know what the right standby matrix is. I mean, each utility has something different and I've heard today that there's problem with those matrices.

So you know, whether there's more granular data or better data out there, hard to say. I'm sure there's -- there -- there could be, but I'm sure there's going to be a cost associated with that and, you know, we have to balance that against the outcome and the output of that and what makes sense.

What we want to do is try to design standby rates, you know, that are cost-based for each utility so that it doesn't incentivize or provide a barrier to customers. That's the ultimate goal. That's, I think, the ultimate goal per the Commission's guidelines for standby. So we have to do what makes sense of how each company system is planned,

but I think we just need to be cautious about saying more data is going to solve a problem with getting, you know, better allocation of cost between as-used and contract.

MR. BOURGEOIS: I'd like to suggest that if we don't have better data than we did 15 years ago, we probably should. And it may cost something, but it's probably worth it. Especially, if we want to get to where we want to be with REV and especially if we want to try to implement some of the things Doug was talking about, I think we really need to know at a more granular level the answer to these questions of, you know, what costs are imposed and what benefits are potentially extracted.

So if we don't know any more than we did 14 years ago, we probably should and it's probably worth investing in as a key component of REV.

And I -- I think that, again, getting back to this complexity and transparency question, I think that's a real important issue because we -- we heard from Jonathan that Tishman Speyer, with some pretty good, you know, VBA Excel spreadsheet modelers, was having a lot of trouble and -- getting this right and kept taking it back to Con Ed and they would only point out what was inaccurate.

Now, complexity maybe warranted and more complexity may be even valuable to get the right result. But if that is the case, I think then that we do need -- I think

Rich suggested this, maybe we need tools that the users can utilize, you know, benchmarking models or some sort of a tool. And we've actually advocated for this. We've talked to Con Ed many times over about providing a tool that would allow the customer to make an investment decision with some degree of certainty in an area that maybe is complex by necessity.

MR. LOUGHNEY: I'll just say real briefly, the -- I think I agree with Bill that the -- the rate should be separate. I think the cost of the delivery service should be separated from the benefits that are provided. I realize right now it's not that way because we have this -- we have this discounted rate performance credit, but that's -- probably an interim measure until we get to the value of D.

So I think it's fine as it is, but I do think ultimately they should be separated. I guess, to me, the ultimate goal is finding out what is the cost of serving these customers and -- and comparing that to the revenues they provide, just like all the other customers that are on the system.

And you know, when we have had cost-of-service studies in the past, standby customer is not broken out. When you ask why, well, basically the answer is there's not enough of them. But on the Con Ed system in particular, and Bill could tell us, but I -- there must -- there must be

more than a hundred, I'm thinking, customers? No?

MR. ATZL: No.

MR. LOUGHNEY: But enough to -- enough to track and to find out what the cost of service is. So I think it's time to figure out what the cost of providing this service -- these customers the services is, and then compare it to the revenue. And if there are -- I guess, the final point is because Bill did touch about this. He talked about, well, it's kind of a zero sum game if the rates go up for some, and you change the rate design, it's going to go down for others or whatever.

I think we have to look at and say if the -- if these customers are being overcharged, then we have to live with the consequences, which means that rates may go down and other customer rates may go up. I mean, that's the way we do revenue allocation for all the other service classes. And I don't know why we have to just sort of treat the standby customers as though everything that happens has to be within that -- that class and nobody else can be affected by it.

MR. STAKER: Is J.P. still on the line? Does he -- any comments there?

MR. PADULA: J.P.? Any comment on the --?

MR. FLAHERTY: Yeah, I'm still on the line. I don't have any. I think -- I mean, I think you guys have

kind of hit everything. I would just say that I think Doug's comment is really interesting, and we've actually looked at -- at -- at some battery storage with Doug.

And I think that it -- it is very appealing in many of the ways that we looked to go to standby on battery storage, but battery storage is a very different gig than -- I mean, I appreciate distributed generation defined broadly, but when we were looking at it, we were looking it at various varieties of engines and generating methods. And so I -- I think that Doug's comment just pointed out that it's a very complicated issue. Some people are going to lose and some people are going to gain.

On battery storage side, it looks quite appealing to go to standby, but it didn't look so great when we looked at other technologies. So I think it only stresses that this is a complicated issue. But I would just stress points that I made and that was just made again that it may be warranted to have such complicated things, but it can't be so complicated that we cannot model it to the utility's happiness. That -- that seems to be impossible for me.

And so I think that even if more complexity is warranted, there's got to be a better way to do this because as the comment that was made by Rich -- sorry -- by Tom at one point was it is very, very expensive to do this analysis. You can't just do this. We had to hire all sorts

of people to be able to figure out how to do this.

And we spent literally hundreds of thousands of dollars analyzing this and chose not to move forward. Now, good news -- bad news for us that we spent all that money and did that, but I would just caution that to go down this road with any decent size DG in the downstate region is just to get to the point that you can make an investment decision is going to cost a significant amount of money.

Never mind making that investment decision and investing all the money. So that's what I want to add.

MR. PADULA: Okay.

MR. STAKER: You know, one point that I hear often is -- is the issue around contract demand. And in the rate, you used to have the option, I'm not sure if it's still there, Bill, but you used to have the option that you could elect what the contract value would be. If you exceeded that, then you paid pretty big penalties. We opted with going with a historic peak.

One of the things that we proposed is that contract demand should be based off of a rolling measured peak demand after the fact. So instead of going back to the historic peak -- because that's the right incentive to incent us to help the building just historically start to reduce its max capacity and to ensure that, you know, much like what they're doing with the performance measurements right now,

just to make that contract value roll with the improved overall peak reduction in a rolling fashion, which -- which I think is a very reasonable approach to finding a level of, you know, agreement here around the contract piece.

Everybody is worried about, yeah, but that one day that we're going to have to step in and serve you, you're going to hit that big peak. Well, we have to have the incentives to put and manage that load effectively. And that's one way to do that, through a reduction and contract peak value through rolling. I think that's a good way to look at things going forward.

MR. PADULA: Does Bill or Mark have any comment on it?

MR. ATZL: Yeah, I would just add that the utility system has to be built to accommodate that customer's load if their DG fails. Whether -- if they perform well over 24 months and they haven't really taxed the system, that's fine. Yet, the system still has to be there, at least the local facilities, to take on that load if the customer's DG fails.

And the -- the Con Edison tariff and the other utility tariffs do have provisions for reducing contract demand in the case where there is some permanent measures or equipment removed, things like that. And the performance credit actually is developed as a form of that.

It was -- it was meant to be a mechanism that compensated a customer for performance that was high enough to be considered, similar to a permanent reduction in demand. So there are methods to reducing contract demand, but there has to be some, you know, greater assurance that it can be achieved.

MR. MARINI: And I agree with everything Bill said. I would just add that, you know, a lot of times we hear the contract demand is too high or is a barrier. I can tell you on our system, you know, the as-used demand for one of our companies is the much higher component for customers. And that just goes to, I think, how -- you know, we don't know how the customers size their generation, you know, how they use it, if they add load, if they're adding more generation or utilizing utility system more.

So we have to be there to serve them for the peak load or the connected load unless there's a permanent reduction, and there's provisions in the tariff to allow for that. But, you know, a lot of how a customer uses the generation, obviously, is up to the customer. And I think we just got to be careful not to assume that the contract is -- is a problem.

As Bill mentioned earlier, you know, you're going to switch cost between contract and as-used. There's certain customers that are going to be affected negatively by

that. So you want to get the cost right. I don't disagree with that. But you also want to make sure that you just don't say contract is too high without knowing what it could affect.

MR. PADULA: On this contract demand issue, I just want to ask customers if you would be amenable to an automated demand response that is controlled by the utility to reduce your contract demand, something similar to like an interruptible gas rate? Just wondering from the perspective of the customer if that would be something of interest?

Any customers have a comment on that?

MR. LOUGHNEY: So it would be -- you have a contract demand that would be reduced to some number less than what the utility might set it at, but if -- let's say it's 50 percent you would have -- the utility would have some ability to reduce the demand --?

MR. PADULA: To ensure that you would never go beyond that amount.

MR. STAKER: It's load limiting --

MR. LOUGHNEY: Right.

MR. STAKER: -- is what you're looking for?

MR. LOUGHNEY: I don't know. I mean, I don't think I've ever talked with anybody about it. Maybe J.P. can talk about it. I mean, I think that it might work for some customers, you know, depending on what their application is

and -- and their ability to shed load, close down facilities, or whatever. It might provide an option that might be attractive and, you know, a way of limiting the cost of the contract demand, so --

MR. PADULA: Right.

MR. LOUGHNEY: -- it's probably something that some people would like.

I don't know if J.P. has any thoughts on it?

MR. FLAHERTY: I can just quickly say that that would be appealing where we have more sophisticated abilities to shed load, but in a standard regular office building for -- to have it be automatic, we wouldn't support -- we wouldn't go down that road just because we needed to put our customers first.

And so if it's an automatic and we didn't have any control over what occurred -- I mean, obviously we would have an agreed upon amount, but even then we need time and -- and I mean, obviously, the devil's in the details in terms of is it a 3-hour notice, 24-hour notice, et cetera, but if it was automatic and we had no choice at a regular office building, that would not be appealing.

In larger complexes like Rockefeller Center, where we have aggregated loads and abilities to shift loads around and have an ice, chiller plans and other things, that would probably be more appealing, but there aren't that many

of those scenarios in New York City.

MR. PADULA: Thank you for that perspective.

There was a lot of discussion about the revenue neutrality provision. And if you go back and look at the Commission opinion 01-4, the standby rate guidelines document from 2001, I read that as, you know, to quote, the Commission said pending appropriate cost of service analysis, cost now allocated to each service, standard service class will serve as the basis of the -- of the design of the class-specific revenue neutral standby service delivery charges.

So that seems to me that it was a -- it was a proxy for some -- some information that we didn't have at the time. And I'm wondering what -- from the utility perspective and others, what you think about the idea of trying to come up -- develop a proxy for the load characteristics associated with a customer with DG.

And maybe use some existing data that's out there, like Tom was alluding to, to come up with here -- here -- here is the load characteristics of what we would call a standby customer class and then allocate cost to that class in the same way that we allocate cost to the other customer classes in an eco-study.

I just want to hear a little bit from the utility's perspective if you think that -- first, if that -- if that's something that's reasonable and if it -- if you

think that that would result in a different bundle of costs allocated to the class?

Because right now, we're assuming that all the class -- all the costs allocated to SC 9 must be collected. And those are the same costs that would be incurred if all those customers were on standby rates. But in fact, that may not be the case if the load characteristics of the standby customers didn't match those of the class.

I'm just wondering your -- your perspective on that?

MR. ATZL: Our read of the order is basically the same as yours. And you know, we've also recognized that we think the Commission had envisioned ultimately that there could be a separate class of standby customers when there was enough customers to form that class. And Bob alluded to that, as well. And for Con Edison we, at this point, have 37 standby customers. It's still a fairly small number. They are more accounts because some of the customers have multiple accounts, but there's 37 customers.

And one of the concerns we always have in having what we would refer to as a small customer class is the volatility of cost study results from one to another. And we've -- we have experienced that in other areas. And -- you know, and that's the main concern is that potential volatility. So you could -- you know, you could do it, you

could do at once, and then you might find that the next time you do it, the results can be significantly different.

I just wanted to add to that.

MR. PADULA: Just one question on that. So we actually -- you actually have data. Do you have the same level of data from all your 37 standby customers as you would be getting from a load research meter?

MR. ATZL: I don't think I can answer that for you right off -- on the spot. For -- for the larger ones, we certainly do because the very largest are on mandatory hourly pricing. When you drop below that threshold, I don't know if what we have would constitute a statistically valid sample. And we can discuss that with you some more in the future, certainly.

MR. PADULA: Just curious. So I'm wondering how the numbers look upstate and if the same low number of customers is an issue?

MR. MARINI: We have about 32 to 34, I believe, customers at NYSEG under standby service, and about 22 at Rochester. You know, I think -- you know, I was there in 2001, as well. And you know, there was very little data on this.

I think the reason the Commission set up the standby rate analysis, you know, or the calculation of standby rates the way it did was because there was no data.

And you had to make an assumption that absent, you know, load characteristics or cost data, we're going to assume that every customer was served under the standby rate structures because you had, you know, standard rate structure. And to get the same amount of revenues, you would collect, assuming everybody was under standby.

So I think it was a reasonable approach, at least at the time, you know, until, you know, you can get either more data or something materialized.

My concern, you know, is that -- you know, you said a proxy of -- proxy to -- to develop, you know, what a standby customer looked like by class. And I just think it would be very difficult to get what a typical standby customer is going to look at. Like I said earlier, we don't -- you know, we don't always know from year to year a customer may not use their generation the same way. They may rely more or less on the -- on this -- on the system at times, depending on, you know, various circumstances.

I -- I know we've done analysis looking at the types of customers we have and it ranges all over the place. We have customers with a -- you know, large generators with large contract demands, large generators with very small contract demands. Some have generators that can cover all their load, some cover part of their load. So you really have a diversity of -- of the kinds of customers that

you serve. And you know, you can -- you can attempt to -- to some kind of cost study and say we'll allocate based on this proxy, but I bet you'll get into arguments on cost allocations just like we do for standard classes when you do that.

MR. PADULA: Thank you.

MR. LOUGHNEY: I guess my problem is that I don't -- so we don't know -- I think what we're saying is we don't know that we're charging the right rates to these customers. If we try to find out, it may be difficult and may end up affecting some customers one way or the other, but that happens with every decision that's made on revenue allocation and rate design. And I -- I, you know, just to say we're not going to do it because it might end up affecting somebody one way or the other, I don't think is acceptable.

I mean, to some extent, the way people are operating their facilities now is probably a byproduct of the fact that -- that you have the rate design that you do. And if you change the rate design, then there may be a change in the way that people operate their plants and they may run them more consistently or something. But I don't -- I don't think it's the right answer to say we -- we can't -- if we do this, it's going to be a problem for some customers and that that -- there's always ways to deal with that on rate design.

You guys know better than I do. I mean, you moderate the impacts. You can change the design a little bit. You could phase it in, whatever. I mean there's all different ways to moderate it. So that's -- I would say that I think it still should proceed.

MR. MARINI: You can -- yeah, that's true, Bob, and you could. You know, you could make an effort to -- to do that. But, you know, we -- I can tell you in standard rate design, you get into those same discussions. No different.

So you can get into the same discussions but oftentimes you end up negotiating that, as well. So it becomes, I think, another negotiation at some point is all I want to say. And maybe that's okay and maybe that's necessary at times, but that's how the original standby matrix was done, too.

So I'm not sure there's just a solution out there, is what I'm saying, that says it's going to just take care of what you don't like today.

MR. LOUGHNEY: If we get -- if we get to the end of a rigorous analysis of determining that the current standby matrix is hundred percent accurate, then I will back off.

MR. STAKER: Marco, just answer the question you posed to Bill. In a previous life, I worked for the

company that put in the meter data collection system for Con Ed. And they have about 1500 meters that are under interval data that would suffice for a study.

Now, as we go through the interconnection process with Con Ed, one of the requirements is that we do put in interval metering into that device after we go on to that rate. So we're in the process right now of automating those meters in the installations we're doing today.

And that's one of the things that I hear in a lot of the proceedings here is that these projects and what we save the end users, we can afford -- we actually put our own metering in. I've been trying to argue that the revenue grid metering, we should be able to supply that information to the meter data management system, but there's a little bit of, you know, fox guarding the henhouse discussion there. So I understand that.

But the metering cost to collect that information, especially on commercial customers, is not that cumbersome and -- and should be -- that should be the first layer of customers attacked as far as data collection. And the information's there. We actually use in in our business today. We have access to Con Ed's customer care system. And that's how we'll go in and analyze some of these larger commercial accounts to decide whether there -- the load is right for storage or not.

MR. BOURGEOIS: And I'd just like to finish with this statement that it seems to me that the data is probably there. The Commission order did leave open this placeholder or potential look at this issue. And I -- I agree with Bob, you know, we should -- we should look at it, find out how -- how accurate these -- these allocations are.

We have the information. We have the Commission order suggesting it would happen at -- perhaps should happen at some time. I think it would be reasonable to do that.

MR. PADULA: Thank you.

Should we move to the questions, either here in Albany or at one of our satellite locations or on the phone?

We'll start in Albany? Any questions here?

MR. LEONARD: Ron Leonard. So I have a question for you.

MR. PADULA: Sure.

MR. LEONARD: How much did Thomas Edison charge its customers per kilowatt hour? I have the answer for you. 32 cents a kilowatt hour. So you now can talk to your boss and tell her that you have stopped the increase in cost in the Con Ed territory for 115 years. You're going to get a raise.

So this discussion was worth the price of

admission for me. And this is, you know, a key thing in terms of fairness to consumers, ratepayers, DG.

And Tom, to your discussion of do we have the data, I happen to have personally seen that we do have the data and I saw it on an iPad, an entire utility in 3D rendered on the iPad by the utility, could walk around in neighborhoods, check phasers, switch circuits. The data is there. That's not an issue. Done deal. And that was 5 years ago. We got better iPads now.

So the real comment that I have here is fairness. And I -- I -- you know, we brought up the chicken or the egg theory of this thing. I'd like to bring that to you, the absurd conclusion. Say you decided that you wanted to have chickens at your house so you could have eggs. And the PUC locally, that's the Poultry Utility Commission, decided that you would have to have a standby fee for your local grocer so you could buy those eggs someplace else if your chickens just stopped laying those eggs and, you know, that's just the way it is.

Fundamentally, that's nuts. And what people will do when they're faced with a fundamentally bad equation is to vote with their feet. Durst did that.

Do we want to make the choice of making a system that's fair and equal and useable for all parties, or wait until people are pissed off enough to vote for with

their feet and cause problems for everyone? This is a solvable problem.

This is a problem that I was faced with personally in the 1980s when we got into the cogeneration business. This is the problem that we've seen for 3 decades after that. We need to, you know, ratchet it up, face the issue, figure out that, fundamentally, this situation is not equitable, and deal with it on a Commission basis and have a ruling that says that DG is limited in this area to this type of a fee, or take the fee and get rid of it, because what we should be doing is looking at value of energy on the grid. And this is the 32-cent number again.

Richard Perez -- Dr. Richard Perez, from the Atmospheric Sciences Labs, did a study on what's the value of solar on the grid, a decade ago. Guess what? It's 32 cents, kilowatt hour. It's a real value for DG on the grid that really this whole discussion ignores. And it's fundamental to the equation of fairness of this type of system being out there.

Previously I alluded to the fact that FERC says that we only get 20 percent of the energy that we take out of fuel and deliver in electricity. That's nuts. Put electricity in the load pocket, you get much more use out of the energy that you are using to produce that electricity. We can't afford this type of waste. We can't afford it,

economically. We can't afford it from -- in terms of pollution.

And we also really need to consider a safety factor involved in the grid that we have which is antiquated and vulnerable. Let's put it that way. Let's make ourselves a little bit more secure. Let's lock DG in the load pocket. Let's make this fair for everyone.

MR. PADULA: Thank you.

Anyone else with a question in Albany?

Any questions from the satellite locations?

Any questions on the phone?

MR. BOURGEOIS: It must be Friday afternoon.

(Off-the-record discussion)

MR. PADULA: I just want to thank the panel for coming and sharing your thoughts. It's been very educational and useful to us and the people who have been participating. And thank you to everyone for participating and all of the other panels, yesterday and today.

Thank you.

(The conference concluded at 3:27 p.m.)

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STATE OF NEW YORK

I, Hannah Allen, do hereby certify that the foregoing was reported by me, in the cause, at the time and place, as stated in the caption hereto, at Page 259 hereof; that the foregoing typewritten transcription consisting of pages 259 through 489, is a true record of all proceedings had at the hearing.

IN WITNESS WHEREOF, I have hereunto subscribed my name, this the 5th day of February, 2016.

Hannah Allen, Reporter