FEDERAL ENERGY REGULATORY COMMISSION

TECHNICAL CONFERENCE

DISTRIBUTED ENERGY RESOURCES

FEDERAL ENERGY REGULATORY COMMISSION

888 FRIST STREET, NE

WASHINGTON, DC 20426

Tuesday, April 10, 2018

10:15 a.m.

Speaker List

--Panel 1---

OEPI-David Kathan (Moderator), Michael Herbert, Kaitlin Johnson

OER-Kent Davis, Lodie White, Joe Baumann

OEMR-Laura Switzer

OGC-Karin Herzfeld, Heidi Nielsen

John Goodlin-Manager, Infrastructure and Regulatory Policy, California Independent System Operator, Inc.

Jeff Bladen-Executive Director, Market Services, Midcontinent, Independent System Operator, Inc.

Joeseph Bowring-President, Monitoring Analytics, Independent Market Monitor for PJM Interconnection, L.L.C.

Michael DeSocio-Sr. Manager, Market Design, New York Independent System Operator Inc.

Andrew Levitt-Senior Market Strategist, PJM Interconnection, L.L.C.

Henry Yoshimura-Director, Demand Resource Strategy, ISO New England, Inc.

Commissioner Cheryl LeFleur

Commissioner Richard Glick

---Panel 2, afternoon session

Chairman Kevin McIntyre-Chair

Commissioner Cheryl LeFleur

Commissioner Neil Chatterjee

Commissioner Robert Powelson
Commissioner Richard Glick
OEPI-Jignasa Gadani, David Kathan
OER-David Ortiz, Kent Davis
OEMR-Jette Gebhart, Franklin Jackson
OGC-Karin Herzfeld, Heidi Nielsen
Christopher Norton-Director of Market Regulatory Affairs, American Municipal Power
Willie Phillips-Commissioner, DC Public Service Commission
Michael Picker-President, California Public Utilities Commission
Ted Thomas-Chairman, Arkansas Public Service Commission; President, Organization of MISO States
Tammy Mitchell-Deputy Director, Electricity, New York, State Department of Public Service
Asim Haque-Chairman, Public Utilities Commission of Ohio
Andrew Place-Vice Chairman, Pennsylvania Public Utility Commission
Ben D'Antonio-Counsel & Analyst, New England States Committee on Electricity
--Panel 3, 2nd Afternoon Session
OEPI-David Kathan (Moderator), Michael Herbert, Kaitlin Johnson
OER-Jessica Bian, Stephanie Schmidt, Anuj Kapadia
OEMR-Lynn Massengill

OGC-Karin Herzfeld, Heidi Nielsen

Katie Guerry-Vide President, Regulatory Affairs, EnerNOC, and Enel X Group Complany

Ted Ko-Director of Policy, Stem

Paul Zummo-Director, Policy Research and Analysis, American Public Power Association

Simon Baker-Deputy Director, Energy Division, California Public Utility Commission

Michael DeSocio-Sr. Manager, Market Design, New York Independent System Operator, Inc.

Mihir Desu-Manager, Strategen (on behalf of New Hampshire Office of the Consumer Advocate)

Roy Kuga-Vice President, Grid Integration and Innovation, Pacific Gas and Electric Company

Marco Padula-Deputy Director, Market Structure, New York State Department of Public Service

P R O C E E D I N G S

MR. KATHAN: Good morning. I'd say we have a pretty full room here. There -- if you can't find a seat in this room, we have set up Hearing Room 1 which is right to the right of this room. If you cannot find a seat here there's seats over there in the other room in Hearing Room 1.

So with that once we -- a little bit of clearing in the room, let's get started. Alright, good morning, my name is David Kathan and I'm with the Office of the Energy Policy and Innovation here at FERC.

And I would like to welcome everyone to this two day Technical Conference on Distributed Energy Resources associated with Docket Numbers RM18-9 and AD18-10. We are gratified by the level of interest that all of you have shown.

Today is an opportunity for us to hear from the panelists that have been pre-selected. To start off, I'd go through a few logistical and housekeeping items. Please, no food or drinks other than bottled waters in the Commission meeting room. There are bathrooms and water fountains behind the elevator banks on each end of the building.

Please turn off your mobile devices or put them in airplane mode while we're in the Commission Meeting Room to avoid interference with the audio/visual and the sound equipment. If needed, as I indicated earlier, we arranged for a spill-over space in Hearing Room 1.

Hearing Room 1 is on the right as you exit this room. Bags will also need to be put in Hearing Room 1. We will break today for lunch at approximately 12 p.m. until about 1:30 p.m. -- on the second day, approximately 12:10 p.m. until 1:30 p.m.

For panelists -- if you would like to be recognized to speak please put up your name card. Be sure to turn on your microphone and speak directly into it so that the audience and those listening on the webcast can hear you.

This Technical Conference is being transcribed, so please say your name as you start to speak. When you're not speaking, please turn off your microphone to minimize background noise. Panel discussions will not include opening remarks, but will consist of discussions based on the questions posed by Commission staff in the notice.

And finally, depending on which direction the conversation progresses, we will not necessarily cover every single question in the notice. We have members of the staff who will help us monitor the time so make sure that we can cover as much as possible in each of the panel sessions.

7 panels will be conducted during this Technical Conference to assist the Commission to gather additional

information to help the Commission determine what action to take on the DER aggregation reforms proposed in the electric storage participation of markets operated by the regional transmission organization and independent system operators NOPR, and to explore issues related to the potential effects of DER's on the bulk power system.

Panels 1, 3, 4, 5, 6, and 7 will be staff led and panel 2 will be led by the Commissioners. We'd like to remind everyone that we intend to focus this Conference on technical and operational issues described in the notice.

We will not discuss other related matters including those at issue in any pending proceedings. So, I'd like to start off and say that today we will be doing three sessions. The first panel will examine the location requirements proposal included in the storage NOPR.

The second panel will consist of a dialogue with states and local regulators on DER aggregation. The third and final panel for today will focus on proposals to address potential double conversation associated with DER aggregation.

So to start with our first panel I would like to welcome our panelists and thank them for their time. We have Henry Yoshimura from ISO New England, Andrew Levitt from PJM, John Goodin from the California ISO, Mike DeSocio from New York ISO, Joseph Bowring, the Market Monitor for

PJM and Jeff Bladen from the MISO.

And before we begin please note we have a number of questions and sub-questions to discuss with this panel so we'd like the panelists to keep their remarks brief. I will now turn to Michael Herbert, also at the Office of Energy Policy and Innovation who will lead the discussion for this panel, Michael?

MR. HERBERT: Alright, thanks Dave. So we've got a number of questions to get through here, so as Dave asks, please keep your remarks relatively brief in hopes to kind of cover as much but we may sort of dig down into some of the individual issues as we go.

So we're just going to go ahead and start from the top, the questions that were in the notice -- talking about the locational requirements for distributed energy resource aggregation. So, acknowledging that some RTOs and ISOs already have or already allow aggregations of DER's and demand response resources across multiple pricing nodes, some of them are considering allowing it across multiple pricing nodes.

What approaches are available to ensure that the dispatch of multi-node DER aggregations do not exacerbate transmission constraints? And I think knowing that CAISO already allows DER aggregations across multiple pricing nodes in some of the other RTOs do as well, maybe we can start with you and then allow some of the other ISOs to react to those comments.

MR. GOODIN: Very good, can you hear me okay. Yeah, good -- well good morning, my name is John Goodin and I thank you for having ISO present today. On this particular issue I think that it's important that if you're going to establish DER aggregations that you impose both size and boundary constraints -- that's something that the ISO has done.

We've borrowed a lot of our distributed energy resource aggregation model from functionality that we established previously for demand resources. And importantly, what we've done with the DER aggregations is what we call the sub-lap constraint if you will. And what the sub-lap is it's a sub-load aggregation point.

It's essentially a zone if you will, an area electrically defined that allows for aggregations within that zone, not without that zone. In other words, you can establish DER aggregations in the specific area and those zones are established by looking at historic congestion and pricing differences between nodes.

And that sub-lap what we have found is that sub-laps are defined by that there is little price differentiation within the nodes within that area.

But there is price differentiation between points outside those areas and so what you have to do is you have to constrain these resources so that you don't exacerbate congestion that you can establish these aggregations within this zone -- which you wouldn't want them straddling those boundaries because you could actually exacerbate congestion, you could call re-dispatch, potential cost uplift, because again there historically has been congestion between those two boundaries -- those two zones.

And so that's been an important consideration again that we borrowed from demand response into our DER aggregation as we've used that same construct in the sub-lap, defining these boundaries. The California ISO has 25 of these boundaries that make up the balancing area authority so they're, you know, not too small, not too big.

The other thing we did in final comment is that we did impose a size limitation. Part of this which we can get into later discussion as how you actually have to distribute the response across the different nodes through distribution factors and some of the concerns about doing that and the accuracy of that.

And so we did impose a 20 megawatt size constraint on the aggregation, as sort of a first step and to test this model. So again, I think it's those two things are key to the DER aggregation model is to impose a size constraint to start, and you have to bound it geographically to ensure you don't exacerbate congestion.

MR. HERBERT: Thanks John, Jeff, do you want to go ahead?

MR. BLADEN: Yes, thank you and my name is Jeff Bladen, I'm Executive Director of Market Development at the Midcontinent ISO. Thank you as well for having us here and to speak to these issues.

On the specifics that California ISO was describing -- I think we generally agree that you can accommodate aggregations within areas that tend to be both topologically and price consistent. But there's a broader set of issues and challenges that need to be considered here and I was thinking back about a little over 12 years ago. I was sitting at this table -- actually Henry Youshimura was sitting down the road from me that day as well in 2006. I think David was at the Technical Conference on Demand Response.

And on that day we talked a lot about what it was going to take to get the demand side, resource capability into the wholesale markets. And what was noteworthy is I went back and looked at my own comments and the comments of others -- was nobody was talking about what was potentially going to occur to the distribution networks if you brought demand response in.

And it puzzled me for a minute because I know we've been talking quite a bit about it here -- at least within the context of this docket. And the distinction that we can't lose sight of is the challenges of taking load off the system which is what demand response is almost exclusively in all of the RTO's versus the challenges of putting supply on to the system.

The need to security constrain the use of any supply resource is something that's fundamental to RTO operations. The notion of security constrained economic dispatch is fundamentally about security constrained at its start.

And so as we think about aggregations -- as we think about building aggregation groups, it needs to be more than just how do we security constraint those aggregations for the transmission system, but how are we going to manage the potential constraints that might occur at the distribution level.

And I know California has done some of that work and I certainly applaud them for doing that. But what I would suggest is that as we begin down this road that we recognize that we don't yet as an industry know what best practices look like in this regard.

That there is an opportunity and FERC has done this repeatedly over the years to use RTOs as laboratories of innovation in a sense, allow some different approaches to be developed and to let those different approaches then inform best practices over time.

And that once best practices can be identified -- and we've done this repeatedly over the years, then bring forward a more common, more -- something closer to a one-size fits all approach.

I would point to MISO's own experience with extended L&P as a good example of that. We spent the better part of 10 years working on extended L&P fast-start pricing as it's come to be known. And it was only after many years of design and implementation and experience with it. New York has a version of it, ISO New England has a version of it -- that FERC then eventually came to the recognition that there's a best practice here that we want to move forward with.

So, as we think about this challenge I think we need to be careful that we don't lose sight of the need for the close collaboration with the distribution network, with the opportunity to move more quickly if we allow the regions to innovate in ways they can uncover best practices that allow us to deal with that real concern that we have in many ways -- our own version of the Hippocratic Oath -- the first do no harm when we dispatch resources.

MR. HERBERT: Thanks Jeff, did you have something

Joe?

MR. BOWRING: So thank you, I'm Joe Bowring, Market Monitor for PJM, thanks for the opportunity to be here and comment today. I think -- so I -- let me build a little bit on what Jeff said. I mean I agree with a lot of what he said.

But let's remember that we are a renewable system, but let's also remember as Jeff pointed out DER's an interesting example. So back when we first started talked about DER, at least in PJM, no one imagined the degree in which it would grow and become a key part of the system.

I think the same thing is true here. We need to think not about what's something in GRTO is doing at the moment, but what the model would be -- what the sustainable model for the significant expansion of DER-type resources which I think we will see.

So it's critical I think, to think about how that works in a nodal system and it's not possible to predict congestion. It's not possible to predefine constraints that are exist or don't exist. A zone is way too big for aggregation.

I would say anything larger than an node -- I know that's an unusual concept today but anything larger than a node would be an inappropriate form of aggregation. It is a nodal system for the appropriate integration of DER into the system so as Jeff pointed out when injections and withdrawals are properly managed and it fits -- fits within the economic and technical model of the RTOs and ISOs it really should not exceed the node.

There's lots of aggregation that can occur behind nodes. There's aggregation that can occur for settlements, but for purposes of injection into the grid I would suggest to you that anything larger than a node is going to create issues which are non-resolvable.

If congestion occurs between -- between what are aggregated nodes, they're permitted -- you cannot prevent that. You cannot prevent injections and withdrawals from aggregating those constraints, thank you.

MR. HERBERT: Thanks Joe, let's just keep going down the line I guess. Mike, do you want to talk a little about the -- I know you guys have a DER road map that you're working on but also how you've sort of considered this issue with respect to your existing, I guess, demand response aggregations as well.

MR. DESOCIO: Certainly. First I want to say thank you for -- for inviting me and hosting this Tech Conference. I think it's a great topic and this is right time to be talking about these issues.

At New York we've been working on a DER road map as you mentioned Michael and we released that early last year. And the path that New York has been taken has been focused on a single node of aggregation.

There's been a lot of discussion with our stakeholders on a multi-node possibility but when we think about that in New York we get worried about how we're going to deal with managing multiple transmission constraints at the same time.

And in New York that happens on a minute by minute, hour by hour basis. In New York it's highly transmission constrained. And when we think about where we expect DER's to locate first and foremost we expect to see DER really come into New York into the load centers were we have a lot of transmission constraints.

And so as we thought about how best to integrate these resources into the system and thinking about the fact that as Jeff mentioned these are going to be resources that are injecting on to grid. We wanted to make sure that we provided as much visibility and operational control as we could because we expect that as DER begins and starts to proliferate the system it's going to come really fast.

So yes, we don't see a lot of it today, but once the system starts to grow we expect it will come really fast. We want to be ready for that. So, you know, one of the things that I'd like to offer is as we think about these issues, we need to be thinking about the longer term future.

I know there is a desire to think about how to get resources into the system right now and that's important because it's going to be important for -- for the policy, it's going to be important for the grid because these technologies are reducing costs.

But as we think about having lots of these resources on the system New York gets really worried about managing competing interests where you've got a dispatch signal now that is asking -- that can't decide whether they have to resource increase or decrease because there's competing constraints that it crosses.

And we don't have that problem today with nodal resources like generators and central station power plants. So these are some of the concerns that we bring up. What I would also like to point out is we do allow aggregations at New York.

We do that for demand response. And we do allow zone aggregations, but we don't have any participation in zone aggregations today. So as much as we hear that it's important, we don't see much of that actually occurring in New York.

And so as we thought about making sure the values were there for DER and making sure that the price signals incented DER to locate in the right places it occurred to us that nodal made the most sense.

MR. HERBERT: John let's go ahead and go to Andrew and Henry and then we'll come back to you.

MR. LEVITT: Thanks Michael and thanks for the opportunity to speak today. PJM shares the concerns of our ISO RTO colleagues in terms of DER aggregations at multiple nodes that would span constraints. They also share concern with our market monitor in that regard.

And this is a concern with respect to market clearing and pricing and settlement and also operational dispatch. I think where our perspective lines up a bit more with California is taking the view that it's more a question of what tools do we have to mitigate those concerns and sort of contain it in a way that can still be useful and provide the benefits of aggregation.

We do think there are benefits to aggregation, in insuring that we have open market access to resources of all sizes including resources that are smaller than our minimum 100 kilowatt minimum's highest threshold and we view nodal only as quite restrictive today given that a developer would have to find 100 kilowatts of potentially say residential scale resources at a single node, not necessarily knowing which customers are at that node -- that strikes us as a challenge.

So the questions are what tools do we have to mitigate those concerns and I think that the geographical approach that CAL ISO mentioned is one that can potentially work, however, PJM more than California we have unpredictable congestion as Dr. Bowring pointed out so we're actually looking at what's another tool that we can use and what's come up is if you have nodal precision in the aggregation, you actually know where each component of that aggregate is -- what node it's connected to and you can model it quite precisely.

In fact it would be functionally disaggregated in many respects to prior to the optimization engines for unit commitment and dispatch running, we would know everything about each unit specifically.

And then after the fact -- after the operating incident, it would also be disaggregated for settlement purposes. Each unit separately uploads what it did and each unit separately gets a settlement line item -- it might be a single settlement check but it would still be separately laid out.

Where it becomes aggregated is just when you're running the day head engine -- just when you're running the economic dispatch optimization engines you said perhaps you have 1,000 nodes in a very wide area zone. You could have 100 miles by 100 miles to a zone, 1,000 nodes -- maybe a particular aggregate is only at four of those nodes so engines would say, okay, I have to pick up this one resource at four different nodes.

If I raise it up to 100%, I'm going to get that one resource at those four nodes and the engine will know precisely what the impact on congestion would be. If it hurts congestion it will not be committed, it will not be dispatched and that really mitigates that problem -- so that's one very useful tool especially from an operational perspective.

The second useful tool is again borrowing CAL ISO's notion of the maximum size in the individual aggregated resource -- so you might find 25 kilowatt resources to build 100 kilowatts. Maybe you find another 20 you can reach 200 kilowatts.

In our proposal once you get to 1 megawatt, you now build a new aggregated proposal elsewhere or aggregated resource, excuse me. So, it does not strike us as a big barrier to entry to say you cannot aggregate beyond a particular point -- you could just split your aggregation in half and have two resources and go on from that as long as the process for updating your aggregate is relatively straight-forward.

MR. HERBERT: Thanks, Henry go ahead.

MR. YOSHIMURA: Thank you. So I think -- when I think about the question of aggregation I think of this as being a method or a means toward another end. And aggregation, as I read the NOPR, talks about using that to facilitate the participation of small resources in the wholesale market and also to insure that the dispatch of these resources contributes to a secure and efficient market.

So -- and I agree with everything that my colleagues have said on the panel thus far. What I want to do is just take a step back which is what does aggregation meet those ends -- mean that they will support the participation of small resources into the wholesale market and will they contribute to the dispatch of these resources such that the dispatch is secure and efficient?

And when I look at the resources that are coming into the New England System -- these are primarily solar PV and energy efficiency -- not entirely, but, but the large proportion of new resources coming to our system consists of those two.

Will the NOPR therefore contribute to their participation in the market? And you have to think about the type of resources that we're talking about -- these are non-dispatchable resources.

They are intermittent. In some cases they're baseload if you think of efficiency as a baseload resource -- so in that sense implementing the NOPR won't really facilitate the participation in the market because these are things that can't be dispatched anyway.

So aggregating them to facilitate their dispatch in the -- in the wholesale market doesn't really contribute to the ends towards which aggregation was designed. So that's the first major point. The second is that each one of us might have different market rules that facilitate small resource participation in the market currently.

And that's certainly true in New England. We have -- and I followed some comments before my appearance today. We have a settlement only construct which facilitates resources of any size or actions -- any resource less than 5 megawatts, between zero and 5 megawatts can participate in the wholesale market, because there's no size limitation there's no real need for aggregation.

These are resources that are paid in node alone when they dispatch and these are resources that are self-dispatched. And so, we have this constrict that already facilitates the participation of -- of small generators in our market currently.

If we then replace that with another set of rules that requires them to be dispatched, that could cause a lot of disruption meaning that some of these resources might opt not to participate in the market at all, only because the rules and the technical requirements for dispatchable resources are more stringent than other types of resources.

So you have to have telemetry, you have to have technical requirements -- et cetera. So we're afraid that implementing a new model of the sort that was talked about in the NOPR would actually cause resources to not participate in the wholesale market and rather, perhaps just participate in the retail markets and monetize their value by reducing wholesale load.

So that's the sort of thing that we're thinking about will happen if we implement this sort of vision that was outlined in the NOPR.

MR. HERBERT: Ask one follow-up real quick Henry -- the settlement only resources, are they -- what services are they providing? Is it only energy and what types of assets are those in your market today?

MR. YOSHIMURA: Right, so they would be energy and -- and capacity, possibly capacity. They don't have to participate in the capacity market but a settlement only resource -- that construct is an energy only construct. However, they can participate as a capacity resource as well.

The types of things that we see participating include as I mentioned, the solar PV, there's a lot of hydro -- small hydro units that participate that way. There's some biomass, you know, methane gas, landfill gas-types of units as well and some wind as well, small wind units.

So in terms of size the hydro dominates and landfill gas and methane, digested gas -- that sort of thing, is also in there and then the wind.

MR. HERBERT: Thank you, John do you want to go ahead?

MR. GOODIN: Thank you I just wanted to respond to some of the comments made by the fellow panelists that first starting with Jeff that absolutely agree that the DER aggregation requires a level of coordination and collaboration that you really don't see up to this point -- not even in demand response because the impacts that DER can have on the distribution system.

Because of that the ISO's spent a year and a half with monthly meeting with our UDCs working about -- working on that TND coordination as rules and responsibilities that the TND interface.

That's probably much easier in a single state ISO than multi-state but that actually bore fruit. There's a lot more work to be done there but clearly acknowledge that these DER aggregations have to be feasible. That dispatch has to be feasible from the T to D and the T to T, that's essential.

As far as Joseph Bowring on the aggregations I would just say that I think that if we're going to go down this policy and under this existing market paradigm that aggregations are sort of going to have to occur -- they're going to have to happen for the small resources for DR and DER.

And aggregations are not something new to DER in the ISO market. We have physical scheduling plants on the hydro system that are connected to multiple nodes that participate as a single resource, so it's not a new construct if you will.

And again, I think as far as a policy we're going to have to figure out how to make that work rather than single node. I just don't see how you can get resources substantial enough to really participate at a single node.

And just for clarification, I said that the ISO DER aggregation model allows for 20 megawatt resource, that's the absolute size of this disaggregated resource. Individual resources are anywhere from .5 megawatts to 1 megawatt. So the sub-resources can only be of that size. Once you exceed the megawatt then you're over on our participating generator -- so I just wanted to clarify that point.

MR. HERBERT: Mike, let's go to you first.

MR. DESOCIO: Thank you. So this is Mike DeSocio again. I just wanted to offer a couple more thoughts that might be helpful as we think about this issue. And as New York has thought about it we've been thinking about this in a more holistic view.

Part of the DER roadmap was to also recognize that there's some state involvements, the policies that are also trying to -- to get DER to enter the grid and become more proliferate with how we operate the system.

And so when we think about that, the ISO has been thinking about wholesale rules that also blend well with distribution utility operations and we've been working with the joint utilities in New York for the last few years on working through coordination agreements and how we would actually facilitate a system where you've got multiple assets down on the distribution grid, but also providing wholesale services.

And there's a lot of coordination that needs to occur -- coordination that we haven't really had to deal with in the past. And as you start to expand the set of nodes that aggregations can occur across, that makes it a little more difficult for a utility to say move DER, that it needs for a distribution need and not cause other issues on the transmission system because -- because the response may not be fully understood or captured by -- by the software that's doing the dispatch.

And we can try to model that but I think what that requires is more information and more information means a higher burden to actually participate in the wholesale market which we're also trying to avoid.

At the same time, New York is really focused on aggregations because we see that as the way to really allow these resources to participate in the wholesale markets. And the size limitations that we're thinking about are -- we think are very -- are not very restrictive.

We're thinking about aggregations where the minimum asset size in the aggregation could be as little as a KW and the aggregation size needs to only amount to 100 KW. So when you start to think about those types of rules, now the multi-node model maybe is not as meaningful as a single node model and so we've been thinking about this in kind of a holistic design view.

How are we going to allow these resources to participate in the wholesale market, but also understand that a lot of them are coming to the wholesale market because there are other needs or issues they're dealing with -- they're being brought on to deal with distribution feeder unloadings and things like that.

And so we're also trying to make sure that as we develop these rules, that we don't create obstacles for coordination with the utilities or obstacles for DER to participate only in one market versus the other.

MR. HERBERT: Thanks Mike. Let's give Jeff and then Henry an opportunity to respond and then we'll -- I think we need to move on to the next question.

MR. BLADEN: Thank you again, this is Jeff Bladen with the Midcontinent ISO. Reiterating some of what you've heard but mostly I want to emphasize one element of the opportunity in front of us because DER does represent an opportunity, far more than anything else, but an opportunity that doesn't come without -- you know, most opportunities don't come without some risks.

And as we think about the decentralizing nature of our grid -- moving away from central station resources towards decentralized resources, distributed resources -- the, the challenge in front of us to capture that opportunity is to do that in a way that maintains or grows the value proposition that RTOs have delivered to consumers, but to do it in a way that's reliable.

And that is really what we're focused on and as my colleague from California mentioned a minute ago -- the challenges of building that common platform for a multi-state region -- in our case more than a dozen states with many dozen local utility operators operating distribution grids is a different challenge, a unique challenge that -- versus a single state RTO for instance that I don't want to minimize the challenge that California and New York have faced in building their approaches but in some respects it was simpler than building a common platform across a multi-state region with many utilities within each state.

And so what I would suggest is that the opportunity in front of us to maintain and grow the value proposition by taking advantage of the capabilities of distributed resources is to allow for the development of the right approach -- the tailored approach which in many cases we've accepted for different regions.

That what we might come up with that is extraordinarily useful in the Midcontinent may be less, less so in other parts of the country and the same may hold true for what happens in other RTOs.

Last but not least, the notion of aggregation -- I think it's important for us to call the question of is it fundamentally required? Is it an essential part of how you would approach this question or is it something more like what we've been hearing which is this notion that let's make sure that resources have access to the extent that they need it in a way that is feasible, that is reliable, and allows them to deliver their capabilities to the market for the benefit of the public interest without focusing solely on the method.

Some of the notions that PJM mentioned early on are also ones that MISO's been thinking about this notion of essentially re-aggregating or re-configuring what might come in as an aggregated group of distributed resources in such a way that we can maintain security constraint across an aggregation and then allow that to be fed into our optimization systems, rather than requiring an RTO on a one size fits all basis to somehow come up with a -- a less dynamic way of maintaining security constraint as it dispatches aggregations.

The notion that you could dispatch part of an aggregation group, for instance, ought to be on the table for instance as you think about the challenges of trying to security constrain the transmission system, let alone -- as I mentioned earlier, a distribution system.

MR. HERBERT: Henry, go ahead.

MR. YOSHIMURA: Thank you. Just one other point I'd like to raise. We could create a very sophisticated set of market rules and infrastructure to create aggregations and dispatch demand, excuse me -- distributed energy resources.

The question then becomes do these resources want to participate in our markets in that set of rules. With those rules you asked me a question Mr. Herbert where, you know, what sort of services can SOGA Resources provide?

We could expand that to include things like operating reserve. By the way, these cell minority resources if they install the right equipment can provide regulation services currently -- none have opted to do so but that's -- I mention that that's instructive.

Because we could give them the opportunity and expend the resources, develop our markets to enable the distributed resources participate. The question is whether or not they will participate. And if they don't participate, is there some other way in which they can participate in the market without participating in the wholesale markets and the answer is yes, they could participate in the retail markets.

They're in the retail space, they're in the distribution system. Often they're behind the customer meter so they're actually retain customers with a resource sitting behind the meter. So apart from jurisdictional issues which I'm sure the next panel will perhaps discuss, there's a question of whether or not these customers and/or resources if -- even if given the opportunity to participate in the markets would actually do so and provide additional services above and beyond what I mentioned before which was energy and capacity.

What's left that would be ancillary services. The ancillary service market is a relatively small market and in ISO New England's case you know, ISO cleared something like a little under 7 billion dollars of settlement money last year.

Most of that's in energy. The next share of that is capacity and then there's a little sliver which is less than 2% of, of market revenues go toward ancillary services, operating reserve regulation.

And there are a lot of requirements because those are reliability products. There are a lot of requirements around them. We need telemetry to know the state of the resources. We -- there's more technical requirements, communication -- electronic communication requirements which get somewhat expensive when you're talking about communicating with smaller resources -- and perhaps we could streamline that but they're still expenses so the question is whether or not by developing an infrastructure well-distributed energy resource want to participate, to provide those types of products -- the ancillary service products.

And in my conversations with various providers it seems like there's very little interest in that, partially because the revenue opportunity is relatively small, the requirements are rigorous and so one has to really think about whether or not developing these capabilities will actually bear fruit -- that there'll be benefits from that, and we fear there will not be.

MR. KATHAN: I have one follow-up and it's directed towards Andrew at PJM. Related to some of the things that Henry was just mentioning -- you talked about one of the tools was to use more targeted dispatch of a, you know, the portion of an aggregation when necessary.

What data -- what, you know, tools, what communication telemetry, whatever, would be needed in order to support that type of targeted dispatch?

MR. LEVITT: Yes so I want to clarify that. The -- the aggregation would not be dispatched in part, it would always be dispatched as a -- as an entirety as it was offered. So in fact, it actually would implement very much as CAL ISO discussed in their DERP rule where there's a waiting that goes along with each node that the seller sort of provides as part of their offer to the market.

We take that waiting and we'll dispatch it accordingly but we would not change that waiting to dispatch part of it.

I do want to say that PJM has many hundreds if not thousands of water heaters -- electric water heaters that participate in our regulation market -- this is an ancillary service that requires telemetry. And so it does seem like there is a case to be made that there is low cost telemetry available for small resources that meets the technical requirements -- at least PJM's technical requirements.

So it's -- it is true that becoming a market resource has -- can be difficult in certain circumstances but some of those barriers may be surmountable.

MR. HERBERT: Great, thanks guys. So the second question talks a little more about transmission constraints and so because transmission constraints change over time would the ability of a multi-node DER aggregation to participate in an RTO ISO market need to be revisited as system topology changes?

So I guess can you talk a little bit about how often those constraints may change and how those changes may impact the ability of aggregations to participate in the markets and we can start -- we can start with John again.

MR. GOODIN: Yeah again for the California ISO as I explained we have our 25 sub-laps, those are the zones where these aggregations can occur. They have been stable. In fact we really established this construct back in 2009 when we reformed our market to a nodal market, we established the sub-laps for transmission revenue right purposes but they've been useful for both demand response aggregations and now distributing new energy resources.

As far as their stability again the topology of the grid is fairly stable. It doesn't change quickly. There are additions in the transmission system, both generation and transmission generators connect to that transmission. But it's generally fairly stable.

And so what we've seen is that we made our first change to the sub-laps in it was about 8 years before we made a change. In fact January 1, 2017 was the first time that we made the change to the sub-laps. I think we grew by two sub-laps, changed some of the boundaries on a couple but overall the sub-laps remain fairly consistent. We understand that there are impacts to market participants, particularly like demand response that have these aggregations set up in the sub-laps that are counting for things like resource adequacy capacity.

And so if you change the boundaries that can really disrupt some of those market arrangements that folks have, contractual arrangements. But again, there hasn't been a significant change in the sub-laps updated January 1st, 2017 minor updates, but fairly stable.

And again, not a lot of persistent congestion or price differentiation within those sub-laps historically so, fortunately it's been a fairly stable construct.

MR. HERBERT: Great, thanks. Let's go back to the left, Jeff?

MR. BLADEN: Thank you again, Jeff Bladen with MISO. I think -- I think it's noteworthy that California's had such stability. I would -- I would add though that we want to be thinking about as Dr. Bowring said earlier, what do we need to do to build a system that's capable of meaningful and potentially dramatic growth of these assets?

And what may have been stable -- certainly in the Midcontinent region over the last few years may well not be stable as we move forward. And as we think about this challenge going forward we are thinking about the need for something that is far more dynamic in nature and our experience sitting literally in the middle of the eastern interconnect with flows coming from north, coming from east, coming from west, crossing the system -- the topology is only one element of the dynamic that will change -- that we are seeing dramatic growth in central station wind for instance.

We are seeing meaningful changes in the resource fleets in other parts of the Eastern interconnect and so all of that is going to drive towards a need for a far more dynamic approach for how you think about dispatching assets.

This is only amplified if, as I said earlier in my comments, we continue a trend towards a less centralized fleet towards a decentralized fleet. The importance of these assets in maintaining security of the system will only grow. So let's be careful that we don't design something that is good for now but really isn't built for the long-term.

And so I would encourage, based on my earlier comments, or reaffirm, encourage, thinking about this as an opportunity to establish a pathway for innovation across the different regions to think about these challenges that are somewhat unique in each region, identify best practices over the coming years and then use that over time to allow us to adopt what we learned from -- from our colleagues around the country.

MR. KATHAN: Joe, I believe you were indicating interest in talking.

MR. BOWRING: Yes. I thought you were going to go down the road but I'll put up my card next time. So I'm surprised to hear that congestion is stable, perhaps it depends on the timeframe you look at. But in PJM congestion is not stable, congestion as Jeff said is extraordinarily dynamic -- it changes from minute to minute, hour to hour, location to location.

There is no way to say that congestion will not occur across a particular transmission path. And the question in point two is you really cannot do it correctly. It will be clunky, it will be reactive, it will be after the fact.

In order to fit a nodal system, it has to be -- resources do have to be looked at. Normally I agree with Jeff, we have to think about what's this going to look like when there's substantially increased levels of DER participation as there may well be. And you have to take account of the actual dynamic nature of the system.

And what's interesting because I haven't really heard a strong argument for aggregation. I'm not quite sure what the argument is. PJM is saying they're getting really, really close to the point where they're going to even to be able to estimate what the waits are -- but is it is going to rely on the DER resource to give them the waits.

Why not just do it? Why not just go all the way. You can't -- you cannot correctly model it if you don't have the nodal information. Why not get the nodal information from the aggregate as aggregation can occur at the sediment level. It's not a barrier to entry to have a nodal requirement.

I mean as NERC pointed out in one of their many reports on the topic. I mean they said to quote them, "The classic net load model up to this distribution system is not valid. DER must be handled separately. There has to be modeling, there has to be data, there has to be static data, there has to be dynamic data."

If this is going to work with the system and system operators are going to continue to have the ability to control the system, both the distribution levels that have been talked about at the transmission level, then we need to know where these resources are. We need to know what they are.

We need to know what they're capable of doing.

In fact we need to know what they are doing in real time, thanks.

MR. HERBERT: Thank you, we have a question from Commissioner LeFleur and then we'll come back and let you guys respond.

COMMISSIONER LEFLUER: Thank you Michael and thank you all for being here. This is a great panel and I just can't resist asking a question now that I'm looking at the people who actually run the system and will make this work.

I accept what I think every single one of you has said that there are substantial coordination issues in making this work because of the nature of the resources, because of -- the fact that you're importing supply from sometimes beyond having the distribution meter, et cetera.

And, but -- that's why we're having this two day Tech Conference. I feel like the pace of technological change is such that if we don't figure out how to do this for the customers we're leaving a lot of value on the table for them, so I appreciate your being here.

My question is -- it goes to something Jeff said and I think other people echoed. Why there should be process differences and how we figure this out or address this among the different regions.

I understand completely some regions have one state and one state ISO or multi-state -- that's a big political regulatory difference. I understand different regions might have different prioritization in CAISO and New York this has been driven as a state priority, other places maybe not quite as much.

But beyond the prioritization issue, shouldn't we try to solve the coordination process once and then sort of spread that as opposed to developing six different ways to do it and then we'll be talking about -- next we'll be talking about borders and we'll have another Tech Conference long after I'm not here about oh my God, there's six different ways to do it, how can we share best practices?

Maybe we should standardize more? Could we skip a step and figure it out? So I'm interested in like what are the technical reasons in your rates or your market design that I don't understand why it has to be different besides the political regulatory reasons -- yeah they're different. Big question but I have the right people.

MR. HERBERT: Go ahead Mike.

MR. DESOCIO: This is Mike DeSocio from the New York ISO. Cheryl that's a great question, and I don't know that the rules are the issue. I think really what the main difference that we've observed in New York is what is the posture of each of the different distribution utilities?

What is their ability to actually see into their own grids, how much data, how much of that information did they already have? And that changes the dynamic of what then an ISO can ask the utility to provide them to help manage the coordination.

So it will be different utility to utility and I think that is what -- at least in the ordinance what we've seen the most is the coordination agreements we're working through have to deal with what information is currently available and what information do we need to go build up and then what is the pace of actually getting there?

COMMISSIONER LEFLEUR: That's for the next panel to sift through. They want this, they regulate these utilities not us so much, you know, the distribution.

MR. HERBERT: John, do you want to go ahead?

MR. GOODIN: Yes, thank you. To your question I think it's interesting because of the modeling, the dispatching, the settling of DER, those are surmountable issues. You hear some concerns about maybe what I would think more around the edges of the reliability of these resources and the effects on the market.

But I think these are surmountable issues. We're doing it and it's being done. But to your question about solving this coordination process -- I think our challenges are really sort of not what's being done but what's undone.

In other words, what's undone is really

furthering this coordination at the TND interface, that collaboration with the UDCs and how we ensure that these dispatches from the wholesale market are feasible end to end.

End to end feasibility is huge. I would say that above and beyond sort of the modeling dispatch, sort of the core ISO functions, that really what I think we are going to enable DER to really flourish you have to address some of the things that are outside the walls of the ISO and the authority of an ISO through FERC.

And I think the three things are really, you know, access to capacity markets and resource advocacy, capacity payments -- that's number one. I think there are interconnection barriers and costs -- number two.

And number three is non-trivial is this lack of sort of clarify around these multiple value streams and how these resources that are providing these grid services to the ISO -- how can they simultaneously provide services to the customer domain or the distribution domain?

And in my opinion, those are the much more weighty issues -- resource adequacy, interconnection, multi-use, than sort of the day to day functionality of managing these DER's and settling these DER resources in the wholesale market.

MR. HERBERT: Henry?

MR. YOSHIMURA: Yes so I think the primary issue that we have is that there really isn't consensus in the industry as to how distributed energy resources ought to be operated if at all.

And the struggle that any ISO would have is whereas we model transmission constraints I don't think any of us model distribution constraints and I think other panels will address that issue.

But then the question is well who is going to do that then? If we're anticipating and this is a big -- if we're anticipating a future where distributed energy resources become very prevalent, that they're a major source of capacity for our region -- by the way New England has a pretty large amount of distributed energy resource capacity already.

With that said, what if we triple that? What if we quadruple that right? Who should be operating these resources? We don't have consensus about that. We know certain things about distribution utilities is that they have -- the tools that are available to them are still fairly crude in terms of operating, gaining visibility and operating distributed energy resources on a very granular level, at the theater level.

Maybe some will want to do that, maybe some will not want to do that and we heard from two ISO's that serve a single state. Some of us operate in multiple states and you could imagine even as one state could have variations with -- among the utilities within the state, think of the states that we all serve for the multi-state RTOs.

We have, you know, in New England, you know it's Massachusetts or New Hampshire, you know -- the delivery of dio-state or Massachusetts. So you could see that there's a lot of variation within the regions and how they decide to operate or not their systems, will dictate then to a large extent, how the ISOs then have to adjust.

If, if distribution companies actively operate DER's within the distribution system, that -- that means that we do something different than what I think we're currently thinking about which is having ISOs operate these resources as though they're wholesale bulk par resources, even though they're in the distribution system.

So again, I don't think we have consensus in the industry, let alone in a single state or within a region. How the best map out, what the architecture of this industry is, with a greater penetration of distributed resources.

Once we have that nailed down I think it becomes very easy. I shouldn't say very easy -- it becomes easier. At least we know what we're aiming for. Right now I think we're -- we're kind of struggling with some of these basic questions as to who's going to operate these things.

And then as they operate the distribution company let's say or a distribution system operator, how do then they communicate with us? So, if that's the case then I think we could then start thinking about requirements and the type of information that we would need, when we would need it, but if -- we're not even there yet.

MR. HERBERT: Jeff, go ahead.

MR. BLADEN: Commission LeFleur thank you and I appreciate the question. It is something that we are very concerned with at MISO not because we're looking for special treatment but because we're recognizing that as Henry pointed out, we haven't figured it out yet.

I think what's important to understand when we think about the -- the opportunity for identifying best practices through innovation that can occur in different places in different ways, is that we're all facing different challenges.

As Henry pointed out you can have different utilities approach the question of how they want to bring distributed resources to bear, what they want, what they're going to invest in, what technologies they're going to us in the form of distributed resources.

Is it going to be gas micro-turbines, is it going to be solar, is it going to be storage, is it going to be something we haven't thought of, fuel cells, all of these have different characteristics and the way in which you would operate them looks differently and the mechanisms that you use to integrate them are different let alone the fact that some may choose to have differing levels of distribution automation or distribution dispatch capability.

So, you know, at MISO we like to think of ourselves as a service provider to the states in many respects. That our job is to take the fleets that the regulators are designing and implementing through their integrated resource plans and optimize that to get the most value you possibly can out of that fleet across a broad region.

And because inevitably, the investment choices within different states is part of those integrated resource plans, we'll look different in each of our states let alone from the Midcontinent to the East or the West.

We have to adjust. We have in our experience, adjusted to choices that have been made around investing in things like wind. We build special products, special capabilities to manage the largest wind ramps of any grid operator on a megawatt basis -- any grid operator in the world, we have larger wind ramps that we deal with every day.

And we have special tools, we have special market elements that are designed to deal with that unique characteristic. So to the extent that we could imagine everybody's grid is going to look identical -- it's going to have identical technologies, identical investments in distribution automation, then maybe today we can say absolutely we can solve this challenge.

I think where we are right now is we don't know yet what best practices are going to look like. We don't know yet what the dominant DER technologies are going to be and that what you have in front of you is a number of companies that are invested in identifying best practices.

And as you've already heard from California, some are beginning to emerge but we still need to figure out how do we get them to the point where we could actually translate them to other places.

COMMISSIONER LEFLEUR: Well that's very helpful and I think that gets down to again different state regulatory choices. But to the extent they're developed dominant technology of solar rooftops, which one might say there already is -- but I mean, you know, distributed solar or car batteries become ubiquitous then we hopefully can achieve some level of standardization of how they're aggregated and fit in so we don't have to -- I mean at some level, you know.

MR. HERBERT: Please.

MR. BLADEN: That's absolutely right Commissioner and I would add, you know, that a few months ago I said to my Board of Directors in a public meeting so we can look back at the notes if anybody's curious. I said that we very much look to our other RTO brethren for ideas how to get it right and I think the way I put it was, "Good artists copy, great artists steal."

So we're going to -- where we see good ideas we're going to take them and adopt them before there's ever a requirement from this Commission for us to do that if it's smart to do in California or New York, we're going to try to adopt that in Midcontinent, just like we think has occurred in places where we've been innovative and others have adopted it.

MR. BOWRING: So in the spirit of brevity the answer to your first question is yes. Of course, we should have the same rules. And the fact that there are all these complexities doesn't mean we should have the same set of rules. The same set of rules will evolve, but we need to start in the same place where everyone is facing the same issues.

And if the wholesale market has set up a set of rules, the distribution utilities can decide how they want to interact with that. The point of the wholesale market really should be open access but respecting the nature of nodal systems and the distribution.

That can accommodate a whole entirely different approaches from different distribution utilities as it should, that's not a reason not to have a single project for us all RTOs. Of course, of course that's the right answer.

MR. HERBERT: Andrew go ahead.

MR. LEVITT: Also in the spirit of brevity I can't answer that question but I'll provide a data point if anyone wants to try to take a stab at it. It is true that the technical situation in California appears to be different from the technical situation in PJM.

We have congestion that crops up anywhere and everywhere on lines across the system and so we do not have the luxury of sort of, of having a geography within which you can aggregate and not suffer the consequences of -- of congestion.

And our solution to that is just to have a smaller maximum size cap of one megawatt instead of 20 megawatts and we are comfortable with proceeding with aggregation regardless.

Again, if we model the aggregation with total precision, we know exactly where the different components of the aggregate are, we will know if it exacerbates congestion and we will not dispatch it in that circumstance.

MR. HERBERT: Alright thanks. I know a few of you had your tent cards up with respect to the stability of transmission constraints. Let's go ahead and get some final thoughts on that, Mike do you want to start?

MR. DESOCIO: Thanks, this is Mike DeSocio from New York ISO again. So -- so in New York I would suggest that we also have transmission constraints that are fairly predictable often.

Where we're also tasked as great operators to manage the grid in times of stress, and recently we've all been asked to think about how we're going to deal with resiliency issues. And as we think about resilience it occurs to at least New York where we've suffered some, some storms that have crippled the southern part of the state for days and weeks.

That having some flexibility, making sure that these resources are aggregated in a way that we can get access to them when we need them the most was also appealing and another reason that we thought about a single node approach.

So, as much as, you know, congestion can change and that's true -- the topology also can change and the times that it matters the most are the times when the topology has changed in an unexpected fashion -- that's when the grid operators need the systems to work the best. That's when the grid operators need to know the information is accurate.

And so that to us was really our underpinning on how we approached the design we did.

MR. HERBERT: Thanks, Henry do you want to go ahead?

MR. YOSHIMURA: Yes, so on the issue of transmission constraints I think most of the people on the panel have concentrated on the real time markets. I wanted to just focus a little attention on the capacity market with respect to changing of zonal configurations.

So let's say you have a DER that is in a zone of some type and it's consisting of, you know, X number of individual small resources. The question that comes up in the capacity market if these things aren't participating nodally, individually that is, is that what if a zone changes and some of the individual assets now fall in a different zone.

How does the capacity obligation -- capacity supply obligation that belonged to the aggregate get divided up? If -- because you could think of a capacity obligation as a financial position taken by a market participant which is satisfied with physical resources.

Or you could think about the capacity obligation is following the individual resource and also in some of our capacity markets, you could take on multi-year obligations.

In other words, you clear as a resource in one year but then you retain an obligation for, in our case, 7 years -- up to 7 years.

So, if that is a possibility within that timeframe the zone changes and some of these assets then get stranded in another zone with different pricing et cetera. The question then becomes how do you deal with that? That becomes a unique problem with those with capacity markets.

And I just pointed that out that that is something that we have thought about with respect to aggregations and how one would have to manage the changing zonal configuration when you have that participating in the capacity market. One has to start from the very beginning -- what is a capacity position to start with?

Is it financial or a physical position? And then from there take if the zonal configuration changes, then you have to do something with how these assets that fall in different zones after a bit of time, how then the obligation gets divided up if at all.

So that's just something that is work that needs to be done. It's work that's not going to be -- it's going to be controversial as well, how we do that.

MR. HERBERT: Okay thanks Henry. I think we've pretty well covered question 3 already with respect to the differences between multi-node aggregations and sort of traditional resources so let's skip ahead to the fourth question.

What types of modifications would need to be made to the modeling and dispatch software communication platforms and automation tools necessary to enable or not reliable and efficient dispatch for multi-node DER aggregations and how long would it take for these changes to be implemented?

Any takers -- Andrew, go ahead.

MR. LEVITT: Yeah, so briefly we do have multi-node aggregation for generators already today as I think CAL ISO indicated they do as well. And so it seems like we are pretty turn key to use that at a high level. I'm sure we'll flush out something that's not a huge implementation.

We also have an implementation for something we call economic demand response which is load side resources not on the capacity market which is 95% of our demand response but instead in the energy market they have real time energy market and that is another tool we might be able to leverage so either of those paths seem relatively straight-forward.

MR. HERBERT: Thank you, Jeff do you want to go ahead?

MR. BLADEN: Yeah, I would add that a number of

RTOs are either currently or are in the later -- are currently in the later or earlier stages of major technology platform rebuilds. In MISO's case we have a 100 - 130 plus million dollar project underway to revamp our market's platform.

And one of the things I would want you all to be cognizant of is that it agreed to if we move to make changes to systems or have requirements to make changes to systems that are soon to be retired, those costs may well not be prudent in some sense.

So if we're two to three years away from new platforms for RTOs that would be, I think it would be wise to consider whether it's necessary to make changes in the short-run particularly if there are a means for access that could be accommodated in existing platforms.

It's -- it's something that we take very seriously, the costs that we impose on our membership and on consumers ultimately as a result of the technology investments.

Just to be clear, our plans for the new platform in MISO's case are to be able to accommodate distributed resources at a far more granular basis than we could today, but that is in the offering it is not something that would be possible in our existing platform.

MR. HERBERT: Joe, please?

MR. BOWRING: Yeah, so as you can tell from what I've said so far I think the challenge is how should -- what modifications would be necessary in order to facilitate RTOs and ISOs being able to do this fully nodally?

And I haven't actually -- I mean I think that really is the key question. I think it would be a mistake to -- as Jeff said, kind of look backwards to an aggregation model instead we should be looking forward to seeing how what changes, if any, need to be made to reduce the required size if that's the barrier to address the issues that allegedly require the need for aggregation so that the DER resources can fit seamlessly into the market without changing the market in ways that are inconsistent with the basic function of the market handling, security constraint, economic dispatch for example.

And I would suggest that the whole point about getting it right now so we move forward in a sensible direction -- DER is a good counter-example. I mean aggregation doesn't make any sense for any resource. We have significant aggregation of demand side resources in PJM. It's caused actual operational difficulties on a fairly regular basis.

If you can only -- if you need, if you need DER to dispatch in one particular area and you have to dispatch it by zone, you're typically going to dispatch the wrong resources and that actually has happened.

The point I'm airing also is about not dispatching if you know -- if you actually know the detail, know the arrangement of the aggregate. The question is why shouldn't you dispatch it that way. But also the question isn't whether the aggregate itself would make congestion worse, I mean let's look on the other side of it -- the brighter side of it.

Hopefully these resources can actually help congestion. They can make the system work more effectively. The only way you will know that is if you know the nodal location has both the static and dynamic information about them. So I regard the resources as a potential huge improvement to potentially hugely improving to efficiency, but that will only happen if we know where they are and permit them to contribute possibly to the -- to the outcome rather than think as kind of preventing harm, thanks.

MR. DESOCIO: Thanks, it's Mike DeSocio from New York ISO and I want to address the question in two -- two methods. So when we thought about the single nodal approach what we noticed is that most of the core systems remain intact. They don't change. What we're really talking about is bringing more resources through the core system.

And so really the changes there are really focused on the bidding platform and the settlement platform just to deal with aggregations as well as making sure that we've got the right metering configurations in the meter data that comes out.

When you start to go to a multi-nodal aggregation, then that scope changes dramatically for New York and we are, as Jeff mentioned one of the ISOs that are currently in the middle of replacing our energy management system in market management system.

But the core engines that we would be thinking about that would need to be dealt with have to do with our systems that we generally don't change or customize because we get them off the shelve -- off the shelve from our vendors.

The energy management system is generally -- those applications are fairly standard. And so the areas that we see some needs to change would be the state estimator package and the contingency analysis package that the grid operators rely on to make sure that we're calculating the impacts that these resources have on transmission constraints.

The security monitor package -- these are all packages that we would normally not have to touch. Then you get into the market software, so the market software needs to deal with how to compute the impact of the multi-nodal aggregation on the transmission constraint so there's changes to how the power flows compute it.

There are changes to the contingency analysis package there. Then you get into other aspects like interconnection requirements. So when you have multi-nodal aggregations and we have to calculate what the capacity requirement -- capacity request interconnection service is, we don't have a method to do that so that's a whole new process we would need to develop to figure out how much capacity could be sold because the capacity is coming from multiple nodes.

So those types of processes need to change. All in all this is a pretty big undertaking and we would refer to this in New York as a complete bid to build change with planning changes.

And in those types of projects and the history that I have had with the ISO, those are typically four or five year efforts.

MR. HERBERT: Thank you, John do you want to go?

MR. GOODIN: John GOODIN, California ISO. Just a quick comment about the ISO sub-lap construct -- again, that's sort of the -- you don't want the perfect to be the enemy of the good. A sub-lap is somewhat of a compromise that enables these aggregated resources starting with demand response and now extended to distributing resources to participate in aggregation.

And so it's not as the other presenters have talked about -- it's not that there can't be congestion between any two nodes on the system -- just the sub-lap when you're looking back over long time that it's below -- it's a low threshold price differentiation and it's not persistent within the sub-lap.

Can there be congestion within? Yes, but again it tends to be really low and not persistent. But again, it is a compromise so we have to understand it for what it is.

As far as this particular question on changes to modeling dispatch software -- a key thing to really modeling your DER because it gets at a couple of the concerns is how do I know where these resources are and what they're up to, what they're doing?

And that's why the distribution factor is so key. One you know where the resource is because he's modeled it at the node. And two, you know what it's doing or you hope, based on the distribution factor which is a biddable -- a biddable value. So they can tell us at any time that 60% is at that node, 30%, 10%.

So you do have a pretty good idea of where the response is coming from and your market application -- network application can take that into consideration. So it's not like you're flying blind with these resources so that needs to be understood.

You actually have quite a bit of information down at the very granular level about how these resources, as resources at the nodes are affecting the system. But the ISO did originally kind of going back as we were modeling demand response and DER originally as generators and we knew that this was not sustainable long-term because in your network application, your full network model that's a heavy lift on the model to try and optimize and do the power flow on all these generators injecting.

And we know that DR and DER can -- the number can quickly overwhelm the number of actual single large generators on your system, yet the system and the network models don't see them any differently even though they may be much smaller. So it's a heavy burden on the system.

So what the ISO did was actually quite an innovative approach is that in the market applications -- so on the front end where you're bidding and scheduling these resources, clearing these resources, that is done as a generator.

So you have all that same sort of front-end construct and bidding platform as any other resource so you can present the attributes of that resource, bid that resource like any other generator.

What we do differently and it was a very unique and creative solution is that when we transfer that solution over to the network application -- a full network model, those DER aggregations become an adjustment to load so it gets translated as an upward or downward adjustment to the load at that node.

And this eliminated that need to build all these tiny little generators in your network model and placed a huge burden on your network model instead these are adjustments to load. And so if you have charge or discharge you can reflect that as an adjustment to the load at that particular node.

And so this is a very creative capability that the ISO developed that I think is pretty effective.

MR. HERBERT: Thanks John, Jeff go ahead.

MR. BLADEN: Yeah just one quick addendum to my comments. One of the other -- one of the other things that is going to be new and unique is finding a way to integrate some kind of situational awareness around the distribution networks conditions that agree to which we have a lot of experience integrating situational awareness from spy assets that will directly translate to how we integrate situational awareness of distribution network constraints to the extent that they will become relevant.

Today we simply don't worry about distribution network constraints. We presume the distribution network can consume -- conserve load to the degree to which it's rate at the bulk interface and we essentially assume that will not change.

We don't monitor conditions below the bulk power interface for the potential for overloads that might be caused by injections on the distribution network. And so to the extent that we're dispatching resources that are below the bulk interface, we would need some form of integrated -- some form or fashion to integrate that situational environment for what's going on on the distribution system -- at least potentially.

And it's something as I said early on that you know, when we dispatch resources our first goal is to do no harm so this speaks to the need for coordination that maybe unique from utility to utility or state to state. If it's not unique it may be somewhat distinct as the relativity may vary as well.

MR. HERBERT: Great, thank you, Henry I think you were next.

MR. YOSHIMURA: Thank you, so just a couple comments here. What Michael said about in terms of implementation of DER aggregations -- we've -- are in the middle of implementing an approach for a demand response. That's proven to be a multi-year task so the observation that it would take four years or so is accurate for in our case.

If -- it would be fairly straight-forward to integrate a distributed generator on a nodal basis accommodating aggregations would be a heavy lift. So, and but something that John said that is interesting which is the notion of modeling or integrating these distributed energy resources as a modification to demand as opposed to utilizing these things or modeling them as small supply resources.

The one thing I've been noticing is that there's a tendency in the industry to integrate resources -- what we call resources into the supply side of the market so, just thinking about the market in terms of two sides -- supply and demand side.

Even with demand response and other resources most of the DER's that we will see will probably be behind the meter. And being behind the meter they will be operated by customers for their own uses, probably to reduce retail costs.

So the question then is in my mind as an economist would be why are we integrating these resources into the supply stack of the wholesale market when their primary function is to modify demand on the system?

In other words, rather than taking these resources, seeing them as supply resources and then modeling them as reductions in load, why not model them as reductions in the loads to begin with?

What that implies is rather than trading the DER's as supply resources, they were the ones that are behind the meter that's going to be modifying demand both of the customer and maybe of -- of a larger zone is that they should be perhaps integrated into the demand side of the market.

The way that's done is that whoever is serving the load of that customer or aggregation of customers -- retail customers, what they would be doing is bidding in the energy market a price sensitive demand curve.

I mean all of us have ways of doing that now but what we would do is encourage a lot more utilization of that, particularly if you have a DER in a particular area that's modifying the load -- that load serving entity ought to be taking that into account when scheduling or buying wholesale power from the wholesale market that the DER will modify the amount of power that's generated by the wholesale market.

And in fact, the -- by integrating on the demand side the intersection of the demand and supply curves will indicate when it's most cost effective for that DER to operate in real time. It seems to me that that's a much more direct way of doing this.

We could also do this approach basically having much more price sensitive demand curves -- that could be done both in the energy market, it can be done in the capacity market as well. That's a -- that currently in the capacity markets load serving entities don't even take positions in the capacity market.

They are allocated in the capacity costs based upon some historic measure of load. We require supply resources to take capacity positions but we don't require those that buy capacity -- those that we allocate the capacity costs to to take positions in the capacity market either.

These are areas where I think we have to be thinking of in order to more efficiently integrate DER's into the market rather than think about them only as a supply resource -- think about them as something that modifies the demand for wholesale power.

And then, if we think about it that way, then we could find ways to integrate these -- the distributed resources. None of them into the supply stack, but in the demand stack. And by doing so what will happen is that the demand curve will shift and generally it will shift in the direction that lowers prices which it should.

So those are ideas that we should be thinking about with our stakeholders and in addition to the various proposals in terms of how to integrate these things on the supply side as well.

MR. HERBERT: Thanks Henry, Mike do you want to go ahead?

MR. DESOCIO: Thank you, I wanted to amend my comments on the systems and then I also wanted to acknowledge Henry's observation about how to treat these resources in the market generally.

So when I thought about our impacts to systems, mostly what I was thinking about how to use a distribution factor like concept like California has proposed and has developed, but as we think about that bids only come into New York ISO once an hour.

And so we also understand that as we have these resources aggregating and providing potentially other services that may not be known to the ISO. There can be fatigue on these aggregations and so we would want that information also to be provided to us through communication channels like Skada so that we have the most up to date information.

And that's why it would affect these other programs because that Skada point would now be used to inform the state estimator to inform the security monitor and inform contingency analysis.

I think to Henry's point about how to treat DER's why not just put them on the load side? I know the New York

ISOs thought about this a lot and we started there. We thought that that was a better approach was to treat them as price responsive load.

But as we started to develop different use cases for what these assets look like it occurs to us that when we get DER aggregations, that the blend of resources and the blend of injection and the load reduction.

So you may have some load that can curtail as well as some ability to inject because you've got rooftop solar storage or whatever happens to be the technology. And so now the offers are spanning both the load side and the supply side.

These offers are going from positive injections to -- to withdrawals because you're going to charge your battery in the DER. And so when we thought about it, it just really meant that the supply side model made more sense for us, not to say that you couldn't do it another way but certainly as you start to get to these dynamics where you have got lots of resources that are providing different types of interaction from the grid and you're blending them into one aggregated offer that goes from positive 10 megawatts to minus 5 megawatts. It's more difficult to just treat them all as load side.

MR. HERBERT: Thanks, Joe?

MR. GOODIN: I want to second what Michael said and follow-up on what Henry said. I think for distributed energy resources that it's not like demand response to where these resources can actually export energy and look and feel and act much more like a supply resource actually injecting energy into the grid versus just reducing slowing down, curtailing consumption which is the demand response.

So I agree with Henry that I think a majority of demand response is probably better suited as a price sensitive or modifying type of resource on the demand side, but I don't feel similarly for DER particularly if it's going to be exporting.

Now there's a lot of DER that is actually let's just say it's storage -- a lot of this is storage, that is actually locating behind the meter. And the reason they're doing that is because the demand and response model is much more favorable, worked out, some of those issues that I addressed with Commissioner LeFleur, the interconnection and how it accounts for resource adequacy -- all of that's worked out on demand response.

Less so on the DER side and why those are still significant barriers that still remain. But again, I think that the DER yes, that can be better suited on the price sensitive side less so the DER.

MR. HERBERT: Thanks John. I have one follow-up question. You've talked about the, the distribution factors that you guys use in California and in response to the -- the NOPR we heard some concerns with respect to multi-node aggregation sort of disrupting nodal pricing and sort of appropriate price formation in the RTO markets.

Is your -- I guess to what extent do the distribution factors that you guys use in California sort of alleviate those concerns and can you talk a little bit about how the offers that you would get from a DER aggregation could be used to insure appropriate nodal pricing?

MR. GOODIN: I wish I could actually respond to that affirmatively. And the reason why is that we established the DER aggregation model back in 2016. We have five contracts signed under our distributing energy resource provider agreement and yet we have no participation.

So again, the reason ties directly back to those three points and others that I made earlier that the participation has driven to the DER side because a lot of those issues that again are at an ISO component but are largely sort of issues that extend outside the walls of the ISO.

Again, there's interconnection issues, resource adequacy issues, multi-use application issues and that's -- those are some of the challenges. As far as the distribution factors, the distribution factors issue is not new to the ISO. It's again, it's what kind of built the DER aggregation model on the demand response model.

Our demand response model allows for aggregations in the sub-laps that I've described and again they also are required to submit distribution factors. Can those distribution factors impact price formation -- absolutely.

And that was one of the concerns we have and that we've had and have is that we want to ensure that these distribution factors are actually accurate because they do impact price formation. Again, we've done it for demand response, but for the DER that's one of the reasons why we've limited as a first step to the aggregation being no larger than 20 megawatts and why we committed and FERC ordered the ISO to provide status reports, because that is one of the issues is how accurate are the market participants following those distribution factors that they can bid dynamically.

They can put it in their bid. If they don't it falls back to a value we have in the master file but again the idea is that you are providing that as part of your bid so you're giving us the distribution and the impacts at each of the nodes.

But, again, I think it's a general concern. It's a very simplifying sort of application to make these aggregations work and so that the network application and the market applications can actually manage these resources and their impacts on the system, it really gets down to that point of -- how accurate are those distribution factors?

And so I think over time, you know, that's something that we need to really understand.

MR. HERBERT: Thank you, Joe I thought you might have some thoughts on this. Can I maybe tweak the question a little bit? I guess -- so if you have, if you have a multi-node aggregation and you know sort of the price and the quantity that you're getting at each of the nodes in that aggregation, is it -- do those concerns about nodal pricing still exist and if they do why do they?

MR. BOWLING: Yeah, I mean if you're getting them accurately then no, but then you have nodal. So I mean that's the point. The distribution factor's that are being used in here are really just allocation factions that you are relying on the DER provider to give them to you instead of getting them yourself.

Why not just go do it right and get them yourself, know what the units are, know what the actual dynamic facts are. Of course they're going to be inaccurate. I mean imagine you have solar as part of DER, what happens if a cloud goes over -- of course it's going to change.

And those kinds of things are real world dynamic changes in what DER does, so having somebody bid a bid distribution factors in that sense -- I mean first of all it creates all kinds of interesting market issues and market power issues.

But apart from that, just in terms of accuracy, it's not going to be accurate just because of the nature of the resources and why not just take the logical step and be nodal because that's an approximation nodal.

If people have information about the nodal resources and the location why not do it right?

MR. HERBERT: Andrew, go ahead.

MR. LEVITT: Yes so PJM's answer to that question is the distribution factors that are used for weighting then the individual components, if those are right, then your price formation comes out just fine.

If they're wrong then you've got the wrong price. That's also true in general they had offers where the quantity is wrong for one resource than, you know, it's -- you're getting something unpredictable happening in that case.

But I will say also that this is one of the reasons when the benefits are having a size cap as well as you're putting a lid on that potential fuzziness, the distribution factors used for weighting are often wrong. So one megawatt size cap is quite small just to put that in perspective to a typical volt electric system power line is carrying on the order of 1,000 or multiple thousands of megawatts.

Our telemetry metering requirement is 5% accuracy so if I'm doing the math right that's 50 megawatts of accuracy on a typical line of the power that we're flowing, one megawatt is a small fraction of that.

And then our settlement metering on our tie lines in between zones which are used for settlement purposes as well is 1% accurate so that's now a 10 megawatt accuracy. Again, one megawatt is one-tenth of that.

Typical generators -- we also have a 1% metering accuracy. A 500 megawatt generator, 1,000 megawatt generator -- just the error in the metering alone is larger than the size threshold on the aggregated supply of significant fractions.

MR. HERBERT: Thank you. John, can you make a quick, quick one and then we'll move one to one more question.

MR. GOODINE: Yeah, I just wanted to respond to what Joseph's comment that price formation is not just the supply side, it's the demand side as well and we want this precision which I agree is important on the supply side.

But we have to acknowledge that the load side also has load distribution factors and is probably far from perfectly accurate. On the load side and yet it's informing the prices at those nodes so again we want precision as much as feasibly possible but we have to understand the load is also a contributor and it's distributed. We don't schedule nodally.

MR. HERBERT: Great, thank you. So we have I think time for one more question. We'll touch on the settlement issues real quick. So we said if the Commission requires RTOs and ISOs to allow multi-node DER aggregations to participate in their markets, how should a DER aggregation located across multiple pricing nodes be settled for the services that it provides?

One approach and I think the approach that you guys use in California, John, is settling the multi-node DER aggregation at the weighted average OMP across the nodes which it's located. So what are the advantages and disadvantages of this approach and are there other approaches that could be considered for settlement? Andrew, do you want to go ahead?

MR. LEVITT: Yeah, so the question is what weighting do you use? So if the weighting used is the actual response measured in, you know, after the fact if it's a revenue meter than PJM support that. That would align with PJM's proposal.

If it's settled as offered then you, you have some potential problems there were they would offer it in a way that's advantageous if they think pricing will be higher on one side of the aggregate than the other, they do not in fact perform to that and they get settled wrong, that would be bad.

MR. HERBERT: Thank you, we're going to let Commissioner Glick interject with a question here real quick.

COMMISSIONER GLICK: A lot of time I'll just try to be quick. Earlier on Mr. Yoshimura had indicated that at least with regard to New England, it wasn't quite clear that aggregation will provide any benefits not even if people were offered the opportunity to aggregate that there may not be a lot of takers with regard to that opportunity.

I'm just curious for the rest of the panel if you think for your different regions if you think there are benefits to aggregation and if you think there is it would be a lot of interest in aggregation.

I know that California is just initially experiencing it but it is curious and if you think what type of interest there is and why type of benefits there might be associated with the ability to aggregate for DERs?

MR. HERBERT: Go ahead John.

MR. GOODIN: John Goodin, California ISO. We believe in the California ISO that there are actually significant benefits to aggregation. We've been doing it on the demand response side. We don't have a single node. You can have an aggregation across the sub-lap, across multiple nodes.

And why is it advantageous -- a couple of reasons. One, it allows for the providers to actually go out and solicit and pull together aggregate meaningful size customers, meaningful as far as from the ISO perspective. We're not trying to manage all these individual, you know, kilowatt-type of resources that they actually have the ability to bring together sort of resources that make minimum sizes that can be optimized by the ISO.

And I think that's the key thing is that aggregations allow for the right sized resource because as we know when you're trying to solve your market and optimize all these little resources you have to sort of have minimum size resources to meet -- we have called a mixed energy programming where you're trying to derive a solution and if you have such small resources that they may be economic on paper but the optimization just can't even see them because of the value that that small resource even at the price cap has on the market.

And so you have to have sort of a minimum size, again, to make these meaningful to the ISO in its market systems and allow the market systems to actually operate these resources and recognize these resources. So I think it has significant benefits.

MR. HERBERT: Thank John, Jeff?

MR. BLADEN: I think it's -- I think it's a wonderful question because ultimately the benefits of aggregation are not obvious and I made reference at the outset to the Technical Conference on Demand Response in 2006 and we talked a lot about aggregation back then.

And as John pointed out, the reason we built aggregation mechanisms, it was a short cut -- there was no magic or clamoring among market fits to aggregate their assets and offer them in on bulk.

It was a shortcut because their systems simply weren't built to do what John was describing where you would have thousands or potentially hundreds of thousands of individual small assets coming in.

I think what the time calls for now as we think the world is going to change meaningfully is for us to explore what technology might be capable of and not assume that the existing paradigm needs to be -- needs to persist in terms of how we think about modeling assets, how we think about integrating them into our technology platforms.

MISO's in the midst of a major technology rebuilt. We're asking ourselves exactly these questions. How can we think about this challenge, this opportunity differently? I think the notion that aggregation is an intrinsic good isn't necessarily true, it is a shortcut.

It is something that RTOs needed to do because the systems that were designed in the '90's were never built to handle the volume that would otherwise be required.

MR. HERBERT: Joe?

MR. BOWRING: Yeah again just very briefly, I agree with what Jeff said. I don't think there's any inherent benefit to aggregation. I'm not speaking on behalf of participants. Maybe they disagree -- they probably do at times, but with me in general but not on this topic in particular. So, but and let's just take the California points.

So in order to have it be meaningful you have to aggregate across multiple nodes to the point where you're no longer accurately representing the input of generation to the system, does that really make sense?

It's not a benefit to the system, even if it's a short-term business benefit to an aggregate which it may or may not be. But again we've heard that it does not seem to have been a positive response to aggregation opportunities.

But just from the perspective of the market aggregation is not -- I don't see either why it's desired or it's not and it's certainly not beneficial.

MR. HERBERT: Mike?

MR. DESOCIO: Thank you, Mike DeSocio, New York

ISO. Just really briefly, I agree with the way Jeff characterized it. Aggregations are important to us and New York believes that aggregations are the way they integrate these smaller resources.

Mainly just because the systems we have can't manage and optimize thousands of different resources and so this is a way to let these resources participate in the wholesale market, get energy value, get operating reserve value, get regulation service value but still allow the computational timeframes to be achievable.

We have mandates to make sure we clear a day in market in a certain timeframe, it's important to make sure the market stays liquid and so those constraints are really what drives us to the aggregation model.

MR. HERBERT: Andrew, some last thoughts?

MR. LEVITT: Aggregation means different things to different people. If it just means market access then it is fundamentally valuable on first principles to PJM. It's very important that one kilowatt, even 100 watt resources have market access.

If aggregation means much, much more narrowly taking multiple resources at different places and pretending that they're one resource, that actually is not fantastic, it is a shortcut and I agree with all the comments that my fellow panelists had about that.

The question is how are you going to balance the trade-offs of having a whole lot of line items in your system versus the importance of having an open market. I will say demand response we have aggregation in that narrow sense of allowing multiple resources to come together into one and it is actually quite unusual.

85% of the demand response of PJM is not aggregated in this way so we do not expect that DER will be aggregated -- wholesale DER in PJM will be aggregated in this way unless residential DER becomes the predominant form of DER overtaking commercial and DER and industrial DER.

MR. HERBERT: Alright thanks so much guys. I think this has been a highly informative discussion and Dave's got a couple pre-lunch logistics to announce.

MR. KATHAN: Just basically saying that, you know, we're going to be recessing until 1:30 and at 1:30 we'll be having a Commissioner led panel and there will be discussion with the state and local so please join us back at 1:30 and then we'll have one more panel after that and close later this afternoon.

(Lunch 12:04 p.m. - 1:32 p.m.)

CHAIRMAN MCINTYRE: Well good afternoon everyone. This is a remarkable sight. It's a gorgeous spring day in Washington at long last the cherry blossoms are in full bloom. It would be a perfect day to be out strolling about with a dreamlike countenance. And yet look, we have a jam packed room for people here to talk about the stupid energy resources.

I don't know whether I should be impressed or depressed but I'm grateful to all of you for being here. We have an overflow crowd and so I should note that we do in fact have an overflow room. So if any of you would be more comfortable relocating to -- I believe it's just one room that way. I'm getting nods so that sounds right and of course we're streaming this live with audio and videos.

So feel free to avail yourself of that option if that is of interest. I need to begin by thanking the wonderful FERC staff for all of the work that went into this Conference. It's already well underway since this morning as you know.

It is no small feat to put -- to put together something like this with over 50 panelists on a wide range of complex and distinct related topics on a matter that is very technical and complex as you all know. So I just want to express my own personal appreciation to the team that put this together.

And as to this esteemed panel before me -- I must thank you, in particular, for coming here and being with us here today and sharing your wisdom, your expertise and your advice on what we should do with this complex basket of issues that we're trying to sort out with your good help and the help of others in the industry. So thank you for being here.

I know a number of you have traveled great distances to be here so we're grateful in particular for those who have endured that inconvenience to be here with us. We're very fortunate to have your prospectus.

We now find ourselves at a very interesting point in time in the evolution of our bulk power system. It's a time of rapid innovation and of technological development that's been under way for quite some time as you know, but the base is not slowing. Indeed I would say the opposite is the case and it is already altering how electricity is generated and how it makes its way to our grid.

And facilitated largely by that technological change and by consumer demand, distributed energy resources -- DER's as we call them have become an increasingly significant part of the power system in ways that affect both retail and wholesale markets.

And across the nation now there already are millions of customers -- residential, commercial and industry that have adopted DER's of one type of another. These resources clearly, are having an increasing role in our energy marketplace.

But integrating those resources and the energy they generate into our grid is not without significant operational challenges. As states and consumers choose to deploy DER's we need to do our utmost to ensure that we maintain the reliability and the resilience of our bulk power system.

We also need to fulfill our statutory obligation here at the Commission to ensure that our rates associated with wholesale transactions that are within our jurisdiction are just and reasonable -- a familiar statutory standard.

And that applies of course to all the resources that make their way to the grid including those that are related to generation and by DER's.

So both of these sets of challenges operational and rate-making/regulatory -- this has stayed very close coordination between our federal regulators here and our state regulators and in the other stakeholders, including private sector stakeholders.

And that bring us to this panel. My personal goal and hope for this panel is to better understand from an operational perspective how we ensure that the multi-directional power flows that are created by DER's produce efficient outcomes at both the transmission and distribution levels.

And recognizing that those operational challenges come with costs, that ultimately must be borne by consumers under the respective jurisdictions at issue -- I would like to hear your thoughts, candid thoughts please, on how we should approach valuing DER's.

As a general matter I hope that you will help us to build as robust an evidentiary record here as we can assemble that will help us to inform our decision-making in this proceeding, help us figure out what to do. That would be the greatest service you can perform to us here today.

And with that I'd like to offer an opportunity for any of my colleagues to begin with some remarks, Commissioner LeFleur?

COMMISSIONER LEFLEUR: Thank you very much Mr. Chairman. I'd also like to welcome all of the participants in this Tech Conference and the folks who are giving up the cherry blossoms to attend, as particularly, the state policy-makers that we're looking at right now -- whether you came from down the street like Willy or across the country like Michael, you are very welcome.

I was fortunate to sit in on the first panel this morning of the RTO representatives and it certainly outlined in case I had forgotten that these are very complicated issues figuring out both the payment and the coordination of distributed resources that feeds supply into the system.

However, I think it's well worth the effort to be looking at it both because of the pace of technological change that Chairman McIntyre referred to and the value proposition for customers here.

When we voted out our final rule on storage and set up this Tech Conference in February, I said I believe there were two broad sets of issues we need to consider. The first is the money questions. Who pays what to whom for these resources? How does the money flow and how do you do the metering and billing to figure it out?

The second are the operating questions. Distribution systems are very dynamic -- we need to figure out how the distribution control center that's controlling all these feeders and has visibility down to the customer, or at least down to the feeder level, corresponds and communicates in real time and ahead of time with the market or the transmission control center that's looking at the larger region.

As with most things we do at FERC almost everything, these questions do not just relate to things we decide but to things that are decided at the 50 state capitals. Rumor has it that the transmission wires and wholesale markets we regulate are actually connected to the distribution wires and markets that you are responsible for.

So I'm -- I'm very much looking forward to your thoughts on both of these issues and I'll have some questions when we come along, so thank you very much.

CHAIRMAN MCINTYRE: Commissioner thank you, Commissioner Chatterjee?

COMMISSIONER CHATTERJEE: Thank you Mr. Chairman, thank you to our distinguished group of panelists who are here today. I also want to comment the FERC staff for all the work that has gone into this. I'm very much looking forward to hearing your remarks and talking through some of these complex challenges.

This is a particular gratifying day for me as I've mentioned previously, in going through the Senate Confirmation Process, Senator Markey and Senator Whitehouse were adamant that I make both storage and DER a priority should I have been confirmed and come to the Commission.

And in the limited time that I served as Chairman I did emphasize my desire to see progress on these -- on these rules. When I came to learn -- when I came to the Commission and in working with our fantastic staff here is that one -- things were not as far along as I had thought prior to my coming into the building.

And two -- there were some complexities in the storage piece was a little bit further ahead and perhaps tactically it was important to sever the two to move forward on storage.

Then Senate staffer Rich Glick and now Commissioner Glick was concerned about that -- that severing and was adamant that this piece not get left behind and in myriad conversations I had committed to him that I would do my part to make sure that we move forward and I think this Technical Conference and this panel today is a significant step in that direction.

And I'm very grateful to you Mr. Chairman for the staff and for our guests in making that happen and I look forward to the dialogue today, thank you.

CHAIRMAN MCINTYRE: Thank you Commissioner, Commissioner Powelson?

COMMISSIONER POWELSON: Thank you Chairman. Let me first start off by looking over to Commissioner Chatterjee and congratulate him on wearing his PJM tie here. It's the truly integrated grid tie. It's got cooling towers, transmission wires and I think there's some battery storage in there as well.

I gave you that tie. I was going to get you a Villanova tie but I doubt I would get that far. Well first let me also --

COMMISSIONER LEFLEUR: Who had 143 for the first reference to Villanova?

COMMISSIONER POWELSON: I didn't say anything about the Eagles okay. Let me start off here also by thanking our staff, the Office of Policy and Innovation as well as OEMR, OEA and the Office of General Counsel for helping coordinate today's Tech Conference.

I'm looking out in the audience and feel like I'm in a NARUC convention here but I think it's important that we hear from NARUC stakeholders and many others that are part of today's panel. You know today here in the U.S. we are facing strong international competition in the development of advanced energy technologies that are clearly cleaner, cheaper and more versatile than the current system commercially available technologies.

And I think it's critically important for us as a collective body here, to hear from our state partners and learn from some of the energy innovation that's taking place across the 50 state compact.

Now I would be remiss in not recognizing NARUC for the work that they've already done. I do not encourage anybody to read this on a Saturday night but this is a very well written document with a lot of work that was done by a number of state Commissions, state Commission staff, Jennifer Murphy is here from NARUC but this is the distributed energy resource rate design and compensation manual that was put together under former President Travis

Kavulla.

And I think the DER compensation manual, excuse me, is a great segue into today's conversation as we recognize that advanced technologies whether it's battery storage or other demand side resources, support the operations as Commissioner LeFleur mentioned, support the operations of this integrated grid which is as I like to remind my 14 year old, excuse me, my 15 year old, my 12 year old -- the way we generate, transmit and distribute power is different than it was 10 years ago when you were born.

And I think we're seeing that in our individual jurisdictions and I think it's a testimony to your leadership back in your individual states and the District that we reside in here -- the work that these technologies are playing in our grid.

And your participation is again, a demonstration of your commitment to energy innovation and it benefits the grid and the benefits the grid provides your consumers back in your individual states. So I look forward to our conversation here this afternoon Mr. Chairman.

CHAIRMAN MCINTYRE: Thank you very much. Commissioner Glick?

COMMISSIONER GLICK: Thank you Mr. Chairman and thank you very much for scheduling this Technical Conference and thank you very much to the staff. This is a very complex set of issues and they put together 7 or 8 very good panels. I also attended the first panel this morning and found it extremely helpful and educational so thank you again.

It's already been mentioned several times at the Commission. In February I issued a storage rulemaking and now we're here considering the second part of the proposed rule to see how and if we go forward with it.

But I personally believe the Federal Power Act requires that similarly to what we did in storage and we eliminate the barriers to the participation of distributed energy resources and wholesale markets and aggregation certainly is a process for doing so.

As the Chairman mentioned earlier DERs are growing at a very rapid rate. Distributed solar accounted for 12% of all new generating capacity in 2016. In California alone as President Picker knows very well is expected to have 12,000 megawatts of DER generating capacity by 2020 -- so just a few short years from now.

Facilitating aggregated DER participation in the wholesale markets can improve great resilience and reliability and reduce energy costs. I look forward to the discussion of this panel to hear how state and local regulators are addressing DER growth and how they view DER aggregation.

I'm especially interested in hearing about the on the ground experiment experience in implementing DER aggregation programs and I hope that we can relatively quickly after this Technical Conference has concluded and post-Conference comments are submitted, move forward with a role designed to eliminate the barriers to aggregated DER market participation.

Thank you again Mr. Chairman.

CHAIRMAN MCINTYRE: Thank you Commissioner. And with that let us know turn to our panel discussion. Our formal would be perhaps, somewhat unusual in that we will refrain from the frequent practice of having successive separate speeches in effect.

And instead we would like in the shortness of time to go directly to Q and A and I know we all have a number of questions for you and so my suggestion is that we just -- we here of the dice -- we take turns posing questions to the panel overall. Please just speak up if you feel that it's appropriate for you to address the question that's been lobbed out.

But I do want this to be interactive. I think we all do, we want it to be a conversation, not just a series of back and forth monologues. So please feel free to interrupt early and often and contribute to the dialogue if I may suggest it.

I'll go ahead and get us kicked off with a question of my own. My principal concern is that as we bring these DER resources onto the grid, we avoid messing anything up is my impressive technological terminology for you. Let's not mess things up.

So let me pose the question this way and kick off our discussion. From an operational standpoint, what are the potential negative impacts that DER participation in the wholesale market could have on distribution systems in your states? And please distinguish if you can, between the impact of individual DERs and the impact of aggregated DERs, which was the focus on the NOPR, the floor is open, Mr. Norton?

MR. NORTON: Chris Norton from the American Municipal Power. I'd like to start it off by saying you know, I represent a group of municipals -- we have 134 municipals and one joint action agency. And many of those -- most of those municipals are not subject to the state jurisdictions so those city councils are the regulator.

And so the operational concern there is that there has to be coordination. They have to know what is going on. Their utilities have to know what DER is being registered and they have to have the time to be able to look at it and make sure that you know, you're not jeopardizing facilities, they need to have operational agreements in place so that when they need to do maintenance to facilities, that they can tell either the DER so it can make itself unavailable to the market operator that way you do not electrocute anybody.

So there are a whole host of issues and it all has to happen through coordination. And it's not that it can't happen, there just needs to be a good tight coordination between the market operator and those individual municipalities and the state utilities.

CHAIRMAN MCINTYRE: And you see that degree of effective cooperation as being feasible and attainable?

MR. NORTON: I would say yes. I mean we've been through trying to do it real quick. We went through a process -- a little bit bigger units -- they would still kind of be DER, at a landfill gas site in PJM. The municipality it was connecting behind the meter, went through the PJM interconnection process. PJM coordinated not only with the municipality but the investor-owned utility that the municipality interconnected to.

Went through the study process, set up the operational agreements and that site's been active now for I believe it's three or four years and it was all, you know, and that was all filed at the Commission through what PJM calls a wholesale market participant agreement.

CHAIRMAN MCINTYRE: Yes.

MR. NORTON: So that there might be some changes to the much smaller, much more distributed sites than that because that was off-sided -- a landfill, whereas you could have something all over a town.

And then you also have the issue of if you go aggregate you might have stuff that is in a municipal, combined with things outside of a municipal and so then you have to get down and drill down to that one asset that may be either on the distribution system of the investor-owned utility or the municipal and see which one is going to cause a problem and make sure that you take that into consideration when you're dispatching those resources.

CHAIRMAN MCINTYRE: Commissioner Phillips?

COMMISSIONER PHILLIPS: Thank you Mr. Chairman. Of course my name is Willie Phillips, I'm a Commissioner in D.C. and I appreciate all the love for the District of Columbia in this room. We often times get overlooked and I want to say of all of the constituents that we have the FERC is my favorite.

You can clap. So I will just tell you a little bit about the District just really quickly. We are a fully restructured jurisdiction. We have a very aggressive, renewable portfolio standard -- 20% renewables by 2020 and actually since 1999 our local distribution company has fully divested all of its power plants and generation in the

District so we're generally supportive of the NOPR's goal and we think that the District can probably benefit from this. We're uniquely situated to benefit.

To answer the question that you put Chairman, about impacts, I think that it's really a resource by resource analysis. And to give you an example of how I view it, when you think about demand response in the District of Columbia. We have a direct load control program.

That program, I don't believe, has any negative impact on our reliability. In fact we use it as a tool to actually shave peak in the case of some type of emergency so I think it can improve the reliability.

Similarly we look at renewables like solar. I think that it's a case by case analysis, it has to happen on the utility level but we have our small generator interconnection rules which I think can go a long way into addressing the reliability concerns.

So that's just a little bit of the flavor of what I think about when I think about the impacts of DER.

CHAIRMAN MCINTYRE: Thank you, President Picker?

PRESIDENT PICKER: Let me just first address your concern about not messing things up. I'm not sure that wholesale aggregation is likely -- at least in California's case going to lead to messing up, it's already messed up plenty.

So go ahead --

CHAIRMAN MCINTYRE: It's not the same applause line.

PRESIDENT PICKER: You got a good one. So there are operational issues and so I worry far more about congestion in the distribution system as a result of the growth of DERs in California. Simply because we have thin grid system that was never designed for a lot of two-way flows.

Two is that nobody really told the fire departments that when they went on the roof of a building with a lot of solar array that that didn't turn off when the building was on fire. So you start to dig into some of the safety issues.

And we actually worked through some of those but it took us four or five rounds of workshops with the solar installers, four or five rounds with sitting down with the firefighters because they all spoke different language talking to the building departments and local governments and talking to the utilities who really did understand what it meant to have it.

We started to get smarter as we saw some of these things starting to build so one of the things that they -- that happened was that we actually started to do some distribution system planning. And what do you do when you have this thin grid and you see 5 gigawatts are behind the meter's solar?

And you start to map the system in the same way that the ISOs have really mapped the transmission system to really figure out where you have hosting capacities. It's not so much just to protect but it's acknowledging that these are trends that are going to happen. That we're going to have a lot of distributed energy resources.

It works in a lot of different ways. I remember when I was on the pubic power side, I was at a meeting and an engineer came in. He seemed kind of disturbed. You know, we asked him what was going on and he said we have our first two-tests for a garage.

And so this was a lot of demand for two level three chargers at the end of a thin radial line. Well then came home, plugged in, everybody else in the neighborhood kind of got grayed out in their 55 inch LCD TV's just didn't work very well.

So you begin to see these things as you apply it. As we move into the era where we see the potential for aggregating and we actually have some, some efforts in that direction. The aggregators in California are the incumbent utilities so far.

The other potential aggregators actually have been working mostly with customers to actually help them arbitrage their electric needs primarily and especially where there's a demand charge.

So there hasn't been a rush yet to go to that market. We're starting to see it and I think my colleague, Simon Baker, may talk tomorrow about our multiple-use tariff program which is designed to figure out when people sell into these different markets, we're actually reserving some of these resources for their own needs and start to look to sell it to the utility or eventually may sell it to other peer customers or may sell it to the ISO.

So all bets are off when technology allows people to do these things. Safety, congestion within the distribution system, the challenge of actually understanding the distribution system in the same way that we actually have mapped and have built intelligence into the bulk transmission system all become important at some scale, thank you, Chairman Thomas?

CHAIRMAN THOMAS: Thank you sir, thank you Commissioners and Chair for putting this on as well as FERC staff for the preparation. I'm Ted Thomas representing the Arkansas Commission as well as the organization of MISO states of which I'm President this year.

The distribution operations have to be managed by some entity in a different way than we've had to do in the past. The safety concerns that have been mentioned require communication with outside folks and those systems don't yet exist in the MISO footprint.

And for both safety, for curtailment -- somebody needs to have the authority when there's a system problem to turn things off. The systems to do that don't yet exist. There's also communication --

CHAIRMAN MCINTYRE: Excuse me, may I ask when you refer to safety are you referring to the same issues that President Picker did or different?

CHAIRMAN THOMAS: And Mr. Norton.

CHAIRMAN MCINTYRE: Okay very good.

CHAIRMAN THOMAS: But it is different. It's not internal to the utility. You have to establish a protocol. But beyond that there's a technological system you need to operate. The inverters for the RTO to see -- there's communication that has to happen either from the inverter directly to the RTO or to the inverter to the utility -- somebody has to operate that system.

And it has to go from this system to the RTO and we heard in Panel 1, you know, they're building that system. It doesn't necessarily yet exist, and so we have two systems that we're building that don't yet exist. And we're starting a bridge from both ends.

And it's important obviously to meet in the middle. The communications thing is very challenging too.

There's a new smart inverter protocol, I EEE 1547. There are some state decisions that have to be made on that. We're at the front end of that to and that's integral to this system of being able to see to provide the visibility both to the person that operates the distribution system and then at the RTO level too.

So there's all these things that have to happen around building a system to manage it that are only beginning to be thought about.

CHAIRMAN MCINTYRE: Very good, thank you, Miss Mitchell? And let me say to my colleagues, do not let me monopolize the microphone, please jump in as you may deem appropriate.

MS. MITCHELL: Good afternoon Chairman and Commissioners, thank you for the opportunity today to participate in this Technical Conference. First I just want to talk about the positive operational benefits. I think we all mostly agree on those.

In New York State we certainly recognize those positive operational benefits of distributed resources as New York has identified in its reforming the energy vision initiative.

We feel DER are key to achieving the state's clean energy goals as well as achieving system efficiency and providing resiliency benefits. DER can also provide benefits to the distribution system such as off-loading constrained circuits.

Additionally, DER can help distribution utilities delay or even avoid capital infrastructure investments by participating through non-lawyers alternatives. So participation of DER in the wholesale markets, particularly through aggregations which allow for smaller resources that otherwise would not be able to participate -- to participate in those markets provides an additional revenue source for those resources.

This allows them to off-set their costs and it improves their business model. So we feel that it's important to allow the participation in those markets. That being said, we also do recognize that there are potential operational impacts or challenges that need to be addressed to maintain safety and reliability of the distribution system.

In New York these operational issues and technical issues are being addressed in a variety of forums -- this includes interconnection working groups that we've established to deal with very technical issues related to back-feeding or voltage control.

The New York State Commission also required the distribution utilities to file what we call distributed system implementation plans. These plans essentially are asking utilities to address all of the issues including planning, operations and markets that will enable the participation of DER.

These also go to addressing the coordination in which I think is a theme that we'll hear throughout the day -- so coordination between the distributed utilities and the New York ISO.

I think you also heard this morning the New York ISO mention its DER roadmap initiative. Again, that's key to developing these communication protocols and operational protocols.

So again, I think the key is visibility of the resources. We're going to need a lot of data to make that happen, proper rules for DER participation and also establishing this communications framework, thank you.

CHAIRMAN MCINTYRE: Thank you, Mr. Chairman you've been very patient.

CHAIRMAN HAQUE: Chairman McIntyre, Commissions, members of the FERC staff, thank you very much for setting this up and thank you for the opportunity to be here.

So are there operational concerns -- yes. Can they be overcome? We think also yes. The Public Utilities Commission of Ohio just completed a relatively comprehensive grid modernization proceeding that we call Power Forward. Power Forward is a proceeding that paired the concept of innovation also with the concept of enhancing the customer electricity experience.

Part of that realm was all things distributed energy resources. So like you, we are trying to figure out how to harness the benefits of distributed energy resources. I think you were asking the central question because it does -- it does the PUCO, it does the FERC no good if as this distributed energy resource world proliferates if there are operational issues that occur on the distribution system.

So here's what we learned in part through Power Forward which was frankly the distribution utility -- the distribution utility role and their set of competencies are going to have to expand as are state Commission's role in competency is going to have to expand.

So as DER's proliferate there will have to be impact analyses, hosting capacity analyses, all of these engineering things that are sort of the -- from a state regulatory standpoint are items that we don't typically see at the Agency.

We are economists, accountants, lawyers, these state agencies themselves are going to have to be more deeply engrained in all of these -- in all of these analyses in order to ensure that distribution utilities are conducting these analyses to make sure that if distributed energy and resources are advancing -- if they're aggregated and advancing in a particular area of the distribution system that the distribution utilities themselves have conducted the right analyses to make sure that if dispatched, that the distribution system will be fine and state regulators will also need to develop that certain level of comfort.

And so I think that this is a now admittedly the state of Ohio has very low DER penetration. But the -- what we are trying to do is get out ahead of the concern to the best of our ability and I think in -- in, while we haven't charted out the policy path post-Power Forward definitely, what we know is that the utility role is going to have to expand.

They may have to act as a clearing house of sorts associated with the DER participation in -- in wholesale markets and the state regulatory bodies also are going to have to expand its level of competency so they fully understand what the utilities are doing and of course there's a compensation piece associated with all of this.

CHAIRMAN MCINTYRE: Thank you, as to your Power Forward program, has that been the subject of kind of a final report or anything like that that reflects some of the lessons learned you've just alluded to?

CHAIRMAN HAQUE: Chairman, not as yet. We finished phase 3 of Power Forward three weeks ago. We expect for pretty comprehensive -- we call it a policy roadmap to be put out by the end of the year.

CHAIRMAN MCINTYRE: Very good, I think that's something that we all would benefit from being able to look at.

COMMISSIONER LEFLUER: Well thank you. I'm really struck by something that Chairman Thomas said which is we're building the system right now. This is a case where I think the technologies may be ahead of all the regulators because it's just happening as we speak.

I have two questions but because I want to hear from everyone I'm going to ask them together so we don't do two rounds. So, this morning at the RTO panel we went back and forth a little bit on how much variety of implementation we needed among the different regions versus coming up with some kind of model that works and then standardizing it so we don't have to do it six times.

And what we heard from the different regions, the region from California ISO to Midcontinent ISO and others was the big variety of prioritization and the level of this in the different states that either a single state or multi-state ISO served.

So I'm interested from each of you, what you see as how fast this is happening in your state. What's the trajectory of, you know, I know some states have targets and goals of storage and are really pushing it. Others are -- it's happening more organically. What do you see as a trajectory that would inform the prioritization in your state or in the region you're here representing?

And then my second question and I'm only going to go back -- do down the road once, is as to the kind of value stack of what these distributed energy resources provide -- be they, generation like distributed solar or a battery array or a car battery or whatever.

Because it seems to me that there's a lot of different values. I mean I said at the meeting it was a like a Swiss army knife. The first value could be to the customer itself, whether through net metering or to save money on the bill or to just use their own energy the way they want to use it in the mall or the university or the house, and just they get that value themselves.

There might be more than three levels but the second level is to the distribution company like -- or the distribution system, the retail system that Tammy talked about. I know there's something -- I'm sure I'm going to get this wrong but like in Brooklyn where they're not building the sub-station because they're doing storage -- it's in one of the Boroughs, I think it's in Brooklyn.

That they're using it to defer distribution costs and so the distribution company is reaping that value and then delivering it back to its customers and bills by saving that money -- and then of course, you know where I'm going with this. The third value is the wholesale -- if it's bid into the wholesale system and big resources could be deferred or deployed differently.

And so how do we decide this? Does the customer get to decide? Is it -- that's where it resides? I mean because ideally we'd want to figure out if the markets work seamlessly between us, then you'd go where the revenue was so if the bigger value to society was wholesale, that would be where the money was and if the bigger value was saving that sub-station that would be where the money was.

But everyone knows the markets are not that seamless so how are we going to -- because I don't think we should do it by fighting. I prefer that we not do it by fighting it out and competing, you know, decisions between us.

So I'm going to start with Michael because he talked about it -- I forget what you called it the multi-use tariff, that sounded perfect. Why don't we just all have that?

PRESIDENT PICKER: I'm going to let my colleagues speak to that tomorrow I think. But I will say that this is kind of a complex area. I do want to push back initially by saying that there are distribution system operators who actually have pretty good management tools to operate the system with a high penetration in DERS.

And I'll go to the example that Sacramento made of the utility district which is on the muni-side -- you know, it's a large utility and in some places small utility in California terms. But they actually have visualization of large parts of their grid -- they know exactly what is where.

Now that came about as a result of their investments in advanced metering infrastructure and a lot of fiber for other purposes -- they wanted to get a time of use rate structure in place.

COMMISSIONER LEFLEUR: That wasn't because of something that California required?

PRESIDENT PICKER: Nope. They just wanted to do time of use. Well there is a requirement that people eventually get to time use but there are utilities who are on a much slower schedule than SMUD was. They wanted to actually be able to meet their summer peaks because it's a very hot community and they have exaggerated peaks on about two weeks out of the year rather than building generation they wanted to use customers.

But they started to see some of these other DER resources showing up and they wanted to be able to visualize it and see the impacts. So they started that good mapping process that I discussed. They also developed in concert with some software companies tools that actually let them see that and then they actually began to coordinate that with their weather map so they could actually look to see when there was going to be inclusion of some panels so that they could begin to actually get very real time impacts of generation from rooftop arrays behind the meter.

So I just want to be optimistic that tools are being generated out there. I know that all the other regulated utilities are starting to do this -- they just have a lot more scope. There's a lot of challenges here and so I'm going to say that we had so many different proceedings in place in California that we had to put together our DER action plan -- it's a roadmap.

It was mostly so that I could keep in my head all of the different proceedings we had for various types of distributed energy resources technologies. But even at the time that we were doing that -- starting in 2015 finally adopting it in 2017, we were fully aware that there was going to be an opportunity to sell into the wholesale marketplace.

So what we did is we divided our vision into three areas -- grid architecture -- that's the distributed resource planning process. Second is rates and tariffs. We had NEM, we had a whole series of other kinds of tariffs that -- that people could take advantage of, so a time of use coming as another demand response tool.

We had the glimmering that people were going to use batteries as a tool to arbitrage into the market. Now we start to see them actually advancing demand response with batteries into the wholesale market very slowly -- we'll come back to that in Simon Baker's presentation.

So each of these requires some thought and some effort to begin to plan it out. The distribution resource planning allowed us to actually begin to do two things. One is we started to look at the carrying capacity of different parts of the grids circuit and where we actually had constraints where we might want to focus and prioritize investment.

Another thing was similar to what the ISO does with their sub-laps and their nodal studies. I identified 4500 nodes and they can actually price at each of those nodes. We're trying to develop a locational benefit net analysis as part of one of our grid architecture which then feeds into the tariff -- which then feeds into the tariff and it allows both the customer to decide whether they want to actually make the investment because they can have additional reliability, which is their consideration as well as arbitraging the demand charge that we have for all commercial industrial customers.

Then, you have the ability to -- to say well, we have some excess as a couple of these battery consumers have -- have with their behind the meter -- is there an opportunity for us to sell some of that demand response for even a discharge into the grid during those 12 peak days when energy use in California doubles in hot summer afternoons.

And we have a couple of businesses that have specialized in that kind of value stacking -- arbitraging for the customers, helping to -- the utility by reducing the need for additional generation, but then demand response on those peak days.

And so the utility now has the option to sell it into the ISO grid. We're not seeing most of those customers for aggregators step forward to do that on behalf of their customers because they're just helping them to arbitrage the demand rates -- that's really what we're seeing at this point.

But we can look for it to scale. We have around 2,000 megawatts of demand response that the utilities have already procured. In the last two years we've actually derived another 180 megawatts in -- in, of demand response through these new technologies in the DER market.

So I think that we're starting to see it emerge. How it plays out however, is hard to really say. Will it continue to be aggregated by the dominant utilities or will we start to see -- if we see more disaggregation of electricity generation, a series of other people step in to take control of that and help to shape the wholesale markets. And I don't have the answer to that.

COMMISSIONER LEFLEUR: Really helpful. So you're saying in some cases at least, the customer put in this machine for itself?

PRESIDENT PICKER: Oh yeah, absolutely.

COMMISSIONER LEFLEUR: And then somebody came along and said hey I can combine you with other people and do something for the distribution company. Maybe the distribution company or someone else -- and then the wholesale would be if the top of the pyramid or the end of the line, whatever, if somebody -- if there starts to be enough of them put up for whatever reason, some of them could aggregate to that level.

PRESIDENT PICKER: Now this is our experience and it's pretty granular and we started 15 years ago with advanced metering infrastructure. I think other people have the opportunity to leapfrog us and to pick off things that work from us, but things that may work from what people are doing with a very top-down approach in New York.

And, you know, it may fit better to just start it to point to New York and create a whole series of markets and press it down. I don't have the answer for all the other states. All I can say is that we build on what we've already done because we have a lot of stuff in place -- so much that as a Commissioner I couldn't keep it all in front of me until we wrote it down on paper and organized it and set dates.

And so if you want to have a sense of how we're proceeding on this, I recommend the DER roadmap. But each of the elements -- the action elements that we list here involves lots of work between us, between DER providers, the three regulated utilities and the ISO to actually develop any of these one potential markets that we'd hope would blossom over time.

CHAIRMAN MCINTYRE: President Picker if I could briefly pick up on Commissioner LeFluer's intriguing question she posed upfront. Who pays what to whom and for what question? And specifically I'd like to ask you about the Sacramento Municipal Utility District Program you referenced whereby if I understood you, the entire SMUD footprint is modeled such as they see everything including all relevant DER's?

What is the pace for that and how is that initiated?

PRESIDENT PICKER: Well SMUD is vertically integrated. They own generation -- the regulated utilities don't own generation for the most part, they contract for it. So they all end up coming back to load. I will say that right at this point what we're seeing is for the regulated utilities their costs of generation are not dominant -- in procuring the costs of new generation is not dominant in their rate cases.

It's actually distribution and transmission infrastructure to move power around and try to solve some of the locational barriers and to frankly just deal with years and years and years of disrepair and refurbishing to deal with these two-way flows.

So in each case, each of the tariffs is going to be somewhat different. There will be different payers in different cases. So for example, for some grid improvements it's going to be the generator or the person who is actually -- if it's a battery facility under some cases that the owner will be buying in the wholesale market, but if it's station power for that battery facility they'll be -- since they're going to be a retail consumer for that it's going to be paid in the retail market.

So it becomes really granular if people can learn from us hopscotch. If New York develops a way to actually create a way to actually create a master market that allows these things to compete more equally. I encourage that, but we have these constraints that have been built by these long-standing tariffs.

Our NEM tariff goes back to 1996. Our Small Generator Incentive Program, our S-Chip program goes back to 2001. So it's very hard to ignore those legislative mandates that require us to actually build incrementally on the expenditures we've made in the past.

COMMISSIONER LEFLEUR: Chairman Thomas, we heard a lot from MISO in the panel this morning.

CHAIRMAN THOMAS: Yes.

COMMISSIONER LEFLEUR: And you're the regulator.

CHAIRMAN THOMAS: I understand the desire for uniformity but that's challenging because the models -- the regulatory models and structures are different. For example, in the MISO footprint, we don't have a PJM-style capacity market. So if you're going to get paid the capacity value we have to mix retail and wholesale because if it's wholesale only, the absence of the capacity value impairs deployment -- similar with the vertically integrated utility.

There's a stranded asset risk that those in that state model -- we have to manage that risk. Now my friends in Illinois always point out we're not all vertically integrated. Illinois has the retail access model.

The second point -- part of the value to me is just price discovery. Knowing what the price is to allow the technologies to compete. President Picker has made some -- that the aggregation there's been utility participation but that's so far. It's a price discovery mechanism.

It succeeds at that if nobody ever participates because you want to invest in optionality. Eventually you want some participation but its price discovery is a big part of that value. Who should drive it -- to me it's got to be consumer driven. When you look at the S curve that technology folks talk about the adoption rate of new technologies, it's consumers that guide that.

And we have segmented consumers. You know, we have some that thing about green as the environment and others that think about the other kind of green. When they both come together, that's when the S curve will take off. But for them to see that value -- that's why to me the price discovery is very important.

And when it comes to the payment, who pays? To me a big part of that and again this is -- is what's the network -- this is borrowing some from the telecom folks -- the net neutrality tax stuff.

What is the network and what plugs into the network? To me the network are a regulated monopoly -- they can deliver that. That distribution management stuff to me is a part of that network. And to me you don't want to be rigid about it. I mean over the long haul you want the beneficiaries to pay but if you're sitting there thinking about it and the reason you can think about it is because the system exists that gives you price discovery to know whether it's a value or there's some value there for you too.

COMMISSIONER LEFLEUR: I think you mentioned that as we know a lot of MISO is vertically integrated, do you think the potential stranded cost risk of the central station resources that those vertically integrated customers are paying for or that the companies built is slowing the adoption of some of the distributed -- or do you think there's still purveyor vendors out there trying to put in solar roofs and all and people see value?

CHAIRMAN THOMAS: I think we're among the low cost states. We're lower than average in the MISO territory. I think that's a bigger impediment but to me a regulator needs to be focused in terms of making long-term investments thinking how through the IRP process, you know, how do we get apples to apples comparisons between not only the traditional stuff, but the traditional stuff, you know, plus what might happen in DER which is outside the utility's control and plus what might happen in demand response or efficiency in all of those things and try through the IRP process to come up with a way to have an apples to apples price comparison.

And also to measure the quantity -- you can tell the utility to go build "X" quantity but you're going to have question mark, question mark, question mark in DER -- that's where the forecasting becomes important.

So we have to manage the total quantity but we need to -- we need a crystal ball of course would help.

COMMISSIONER LEFLEUR: Yes.

CHAIRMAN THOMAS: But we don't have one of those so we need optionality and in the EIRE process, you know, reserve a portion and then watch and see what happens and if you have to bump the utility to do more or perhaps even do less, then you would do that.

COMMISSIONER POWELSON: I just want to pick up on the Chairman and Commissioner LeFleur's point. As I listen to the conversation you know, the FERC was ahead of the curve if I can use that term lightly here, with what we did with FERC Order 745 where we had an emerging market on demand side resources.

And I look back to my colleague from Pennsylvania and probably my colleague in Ohio who had to deal with this issue within an organized market of how do we value that demand-side resource in the wholesale markets?

And then unbeknownst to us we find out that it was being treated in the wholesale markets and then where there is a utility energy efficiency conservation measure, that we had an unintended consequence of double-counting or double-dipping in that market.

So I want to throw this out to you as economic regulators. How do we avert that scenario as we design these compensation metrics for DER resources? How do we -- how do we give solace to consumers back in our individual states that we can avert that kind of situation unfolding?

CHAIRMAN THOMAS: To me if you can draw the line between the wholesale and the retail and let the states choose whether to mix it or not. Because if there's forced mixing -- some states are interested in this as staff resources, some states don't. If you force it then you're going to get a screwball.

They're complex issues that we can work through. Our engineers will figure it out. We might not figure it out in 180 days or 270 days but we'll figure it out and there's enough states that want to figure it out. There's a critical mass of states in the MISO area that want to figure out how to mix it -- we'll figure it out and then when we develop a model -- you know, every state doesn't have to do it at once.

We'll build the model to states that want to figure it out and if there's economic value there then the other states can adopt it. And to me that helps with the jurisdiction thing too. Have the wholesale thing separate, allow the states to decide whether you're going to mix it because it's a very complex issue.

There are enough states that want to do that and want to work on that and you know, we'll figure it out. When the wind came on the forecast variances were large. They're not large anymore, we figured it out. We'll figure this out too.

COMMISSIONER CHATTERJEE: If I could build on that response and Commissioner Powelson's question. The context of demand response to Commission provider states with an opt-out -- could you all comment on whether an opt-out provision for DER's would be important to your states?

And if the Commission were to include an opt-out provision in a final rule, how would you make the decision on whether or not to opt out?

CHAIRMAN THOMAS: To me I don't know about an opt-out of everything. Let the states opt-out of mixing. To me that's a line that we can draw. It gets more to the bright line that the Supreme Court used to talk about to the fuzzy line that they created in recent years.

COMMISSIONER LEFLEUR: What do you mean by mixing?

CHAIRMAN THOMAS: Mixing wholesale and resale compensation for the same DER asset.

COMMISSIONER POWELSON: So to be clear, what you're saying is that if you are selling -- if you are selling at the retail level, at the distribution level the state could tell you not to sell at the wholesale level?

CHAIRMAN THOMAS: The states tell you to pick one or the other rather than trying to capture the value streams because that's where the double-counting risks and those risks exist that some states are in the process of tackling but others are not. That way you don't have unintended consequences -- it's not an opt-out such that we don't want any DER to participate in wholesale.

It's just that when we're trying to capture these value streams -- like storage is so flexible it's, it's nuts -- it moves, nothing in this business moves. You can pick it up and move it to a different place.

To capture all these different value streams is a complex question and let the states decide whether you can participate at the same time in retail and wholesale, have your wholesale the way it is under 841. To me that -- that is a logical way to do it that protects the states from unintended consequences.

That gets folks that think they can run a business model wholesale not only the opportunity to do so and gives the states the opportunity to develop all these things that we're trying to build including the systems to do all of this stuff and then the policy -- to capture the value streams.

CHAIRMAN PLACE: I'm sorry, I may jump on that because I think I take a slightly different perspective on that. I think to me the proposition here -- the value proposition of aggregation is a mixed hybrid system where people -- where the only way for this market to grow as I see it is to have the opportunity where you can mix and match.

I think if you sell people it's one or the other I think we're fixing the system we've had. We're not looking to the future on what this value could bring. And I'm certainly cognizant of Commissioner Powelson's comment about unintended consequences -- it's a real concern.

But I'm not allergic that you will have people applying in both but price transparency, engineering, accounting principles, rules -- this is not the first rodeo for Commissions in dealing with rules and rates to manage that space.

Yes, we can get blindsided but that's for me, no reason not to go down that route because as I noted it's to me the true value of doing this.

CHAIRMAN THOMAS: I don't think Commissioner Powelson disagree -- to me going to lengths starting there and then let the states figure out how to bring it together.

I agree that you shouldn't just separate it and say never, but that's not where you end. Let the states work through it.

CHAIRMAN HAQUE: Sorry, I think if -- let me continue down this line because we may, we may collectively all have different opinions about this conceivably. So Ohio's position is definitely that DER's should not be compensated for the same services or products at both the wholesale level and the retail level.

Now they could potentially in the PJM marketplace participate in a market and also receive what would constitute a payment under the net metering tariff, but as long as they're not receiving payment for, for instance, energy on the -- on the retail side as well as energy from the PJM wholesale markets, we're okay.

They can participate in both from Ohio's perspective but they should not receive payment for both on the retail side and the wholesale side for both the same service, so maybe a little of nuance there -- Commissioner?

COMMISSIONER POWELSON: Well to pick up on that too, I mean it's not insurmountable and I thank you for hosting me yesterday in the great Buckeye state.

CHAIRMAN HAQUE: My pleasure.

COMMISSIONER POWELSON: Yes, I made it home okay so. But just picking up on that and my friends from A&P who

I met with, you know you look at as these markets evolve and we look at again, this compensation metric for this research -- do you ever vision and Chairman Haque in your state and Andrew back in Pennsylvania, where these resources could be part of a discussion whether it's an energy efficiency mandate, putting a value around it in that construct, or as states now potentially are amending their renewable portfolio standards -- could that, could this DER I think California is ahead of all of us there, President Picker is that --

COMMISSIONER LEFLEUR: Hawaii is not here but they're still only 100%. So I always say that I promised Lorraine I'll always mention it.

PRESIDENT PICKER: They don't have wholesale markets.

COMMISSIONER LEFLEUR: Yeah.

COMMISSIONER POWELSON: They also have 43 cent distribution rates so let's --

COMMISSIONER LEFLEUR: They're an island.

COMMISSIONER POWELSON: That's right. So pick up on that and give us your state perspective thoughts.

CHAIRMAN HAGUE: Multiple revenue streams are okay, just not duplicative revenue streams. And that's where -- that's Ohio, that's where Ohio was situated. I can't speak for the rest of my colleagues but that -- that is where we're situated.

Now let me try and get back to also Commissioner LeFleur's question about the -- who makes the decision and from our perspective and really the basis for all things Power Forward is the customer's decision.

The customer wants to install whatever distributed energy resource, his or her, its property and they get to decide what -- how they choose to be compensated. So if they think it easier to say on the net for now -- they think it's easier to stay in a net metering tariff because they just like the credit to roll over to their next bill, that's fine.

And they could be compensated for those products and services that they would have obtained in the wholesale rate through -- or in the wholesale marketplace from PJM if they decide that they want to participate because maybe the -- maybe the net metering tariff is not as lucrative for them if they decide that there is an entity that comes in and aggregates them and they can receive more in terms of a check even from a third party and that's their goal is to maximize the value of that resource -- that's acceptable to us as well.

Through Power Forward we had discussions surrounding the concept of what does in front of the meter and behind the meter mean anymore, okay? And it's a really interesting theoretical discussion to have, but I think this is the construct that we're still dealing with.

So Commissioner LeFleur, I'm getting your -- I'm getting to this question as well about the three levels of potential DER participation and this is really about the utility ownership okay, so that's our position on the behind the meter side which is -- let the customer install and choose, okay.

COMMISSIONER LEFLEUR: But of course the customer choice is going to be informed by the incentives we send either in tariffs or in net metering rules or in if the New York DPS wants something in Brooklyn, but yes, but then they make the choice within those revenue streams they can see.

CHAIRMAN HAQUE: That's right and on the distribution utility ownership I'm just speaking for myself, not my -- not the other four members of the Agency because all of this has to be flushed out through what we decide in Power Forward. But it does appear that there is the opportunity for distribution utilities to integrate DER's into what we typically would compensate for in distribution rates for the benefit of the distribution system, okay?

So if that happens, we'd have to discuss process, we'd have to discuss ownership okay? But if that happens that is a separate animal in and of itself and so if the distribution utility decides to try and maximize the benefit of that resource in the wholesale markets or does that revenue stream go to -- now if you think about it conceptually and if that DER is going to be integrated into the system and it's going to be essentially part of the distribution system, likely recovered through DU8's or some kind of potentially rider mechanism, then it would be arguable that any benefit received through wholesale markets should also -- should offset the cost to customers for implementing that.

So, I think if we're still using the in front of the meter, behind the meter convention you've got the behind the meter opportunity for a consumer to utilize wholesale markets as well as net metering tariffs.

And in front of the meter if it is going to be part of the distribution system, then that is something that the state regulators would deal with through whatever state regulatory mechanism is available to them to incorporate that into the D system.

And the very first question about how fast is this moving -- Ohio -- not that fast. I mean we are getting out in front of this and to President Picker's point we want something comprehensive and we've got -- well I think not 390 megawatts in nameplate capacity of distributed generation in the state, a whole lot -- but I will tell you the -- the item that is becoming hot in Ohio and as a result of some of the folks Commissioner Powelson met with, the smart cities endeavor in Columbus that we're very proud of is the electric vehicle charging station.

So, so again it's rising slowly but there are some hot issues out there.

COMMISSIONER POWELSON: I thought you were going to mention a hot issue with a company up in Akron, but that's for another saga right?

CHAIRMAN HAQUE: I have zero comment on that.

COMMISSIONER POWELSON: I will stick to the script.

CHAIRMAN MCINTYRE: Moving right along. Could we hear please from Mr. D'Antonio?

MR. D'ANTONIO: Good afternoon, thank you very much. Ben D'Antonio. I'm here on behalf of the New England States Committee on Electricity. That's our regional state committee and I'd like to be responsive to some of the questions but the conversation has meandered a bit.

Commissioner LeFleur in terms of the trajectory -- at this point in time the operational impacts in New England, they're unclear. We have a very diverse set of distribution systems, various levels of infrastructure, advanced metering, et cetera. So we're not really sure what the operational impacts are at this time.

We do have some distributed energy resources, not much aggregation that's participating, you know, meaningfully yet. We do have several states that are actively exploring some of these operational issues. Massachusetts has a grid modernization initiative. They have a long-standing technical review standards group that deals with some of these sticky technical issues.

So we're actively working on it but you know, some of our states have pretty ambitious goals and others do not. So it's not quite clear how quickly this evolution will happen here in New England.

But I think from our perspective, anything that the DER aggregation does moving forward, it's going to need to be consistent with the interconnection and integration requirements that we place upon our distribution utilities trying to get at the -- who decides and who pays question.

I just want to bring up how important we view the distribution utilities in New England. We view them as having a critical gate-keeping role as well as an administrative and oversight role. Given the important nexus between the states and the distribution utilities in New England and I imagine other places.

We're really expecting them to play just a critical role in this trajectory and evolution. And in terms of, you know, who decides and who pays I think that I agree with the other panelists and the Commissioners who had spoken before where it's going to be the tariffs, the requirements, the incentives that all of us together have put in place that are going to guide some of those decisions moving forward.

Commissioner Powelson, in terms of double compensation -- again we view the state's oversight role and coordinating role with the distribution utilities and our regional system operator to be critical in guarding against any double compensation issues.

I think that, you know, the level of compensation versus being paid twice for the same service -- there's a debate there. And we don't need to get into that but due to the fact that we think that our distribution utilities are going to drive a lot of this for us, we're viewing them as gatekeepers against that outcome.

And lastly, Commissioner Chatterjee, in New England we haven't heard a lot of demand for an opt-out provision. I think that we're asking for flexibility to continue to proceed cautiously yet steadily so thank you.

COMMISSIONER LEFLEUR: I was going to say this is probably a good segue to Tammy because you have the DSO model in New York right?

MS. MITCHELL: Yes, thank you. So I'll just briefly go back to your first question about the desire for standardization. I mean we recognize that desire, you know, for simplicity, to avoid seams in the future. However, I think you've heard today that there are existing regional differences. There are also differences in where we are in the development of the framework for the integration as DER resources.

So from our perspective, our concern would be that we don't try to achieve uniformity at the expense of slowing down our efforts going forward to integrate DER. With respect to the value of DER as you probably know in New York State we actually are developing retail tariffs called Value of DER Reader Tariffs.

Those are intended to recognize the various values that DER can provide energy capacity, the value to the local distribution system, environmental benefits. So those retail tariffs are being developed with those various values in mind. I think Commissioner LeFluer you pointed out that a customer -- a DER developer might -- might purchase DER, might invest in DER based on what the signals are out there.

So we do recognize that there are values of DER to the distribution system and to the bulk transmission system as well so we want to recognize those values, we want to monetize those values and we want to develop rules around that.

That being said, we support the idea of DER being able to participate both in retail and wholesale markets. There's a lot of work in developing the rules and the protocols for that to happen. Certainly, as a regulator, as an advocate for the ratepayers, we don't want inappropriate double payment for the same service that will raise the costs to ratepayers so we need to be cognizant of that and we need to develop the appropriate rules, but we believe that that's possible to do and we are in the process of doing that.

CHAIRMAN MCINTYRE: Mr. Norton?

MR. NORTON: From the perspective of the municipals, probably at a little bit different size scale here. You know, AMP has members that have maybe 100 customers or some even a little bit less than that. So you also have to keep in mind that the utility personnel -- there are fewer of them.

So when you come to the double compensation issue if the resource is allowed to choose -- oh today I'll be in the wholesale market, tomorrow I'll be, you know, I'll be retail many or whatever, that could create issues for those personnel to try to keep up with that.

And especially if you take it all the way to the level that you know, we're now under 5 minute settlements or shortly -- at least within some of the RTOs we're going to be under 5 minute settlements. That could present a very significant challenge for small utility personnel to -- to keep up with that.

As far as penetration that Commissioner LeFleur asked about, I probably got about 134 different answers on that. You know, small local communities, you know, maybe not economically such a great position right now where you're not seeing any of it and then you have other communities, especially around some of the colleges where you see lots of penetration.

CHAIRMAN MCINTYRE: So if I'm taking your point correctly then as we proceed on this we have to be attentive to these challenges you reference -- operational, technological and administrative.

MR. NORTON: Yes, and it's going to be size -- especially for the municipalities, it's going to be size dependent. You'll have some of the larger utilities as was referenced by President Picker.

I don't know if any of our members are quite as advanced as Sacramento is, but you know, we do have members that have pretty advanced systems that can dynamically set protection relays on substations remotely and they have automated meter reading and it's not that hard, you know, it's just a meter installation and they already have a system that could configure it in a DER, they you have others that, you know, I don't know -- I haven't had one on my house for a long time.

But you know, you used to have those little meter things that spin, you know, I haven't seen one of those in years where I live. But you know, it runs the gamut with especially the smaller utilities.

CHAIRMAN MCINTYRE: Commissioner Powelson?

COMMISSIONER POWELSON: To answer, to go back to the question Commissioner LeFleur posed about value and interest -- in the District of Columbia, you don't have to go very far to run into someone who's a genuine energy expert.

So we have a very educated constituency and if it goes down to what my colleagues said about what people want, here in the District people are dying to get at this. I think part of the problem is what the Commission identified is that we have -- how do you compensate?

I think if we figure out the compensation issue people will come, regarding the double compensation question. I actually support -- we support in theory, not allowing people to simultaneously get double payments.

I think to my colleague from Ohio's point, if you can have an opportunity where there's a device where they can participate non-simultaneously, both in the wholesale and retail market -- that's something I would not want to foreclose. In fact NARUC mentioned that in their comments that this is something that may require more study.

So I don't want to be too overly broad on that point. There was a question about what is the value. For the District of Columbia, you hit it on it Commissioner LeFleur, it really is deferring costs for investments.

We're looking and billions of dollars of investment in transmission in and around the District of Columbia. In fact if I were to call a working group tomorrow to talk about non-wire solutions in the District of Columbia to defer cost, we'd have hundreds of people show up.

This is something that is very, very on the front minds of people where I am and I just want to hit the standardization issue as well.

I want to caution against a one size fits all approach. Earlier this morning we had people talk about how RTOs are often the laboratories for this sort of thing. I think that that's good advice. I think that flexibility is the word of the day and I think that there's a stakeholder process -- as least in PJM where that if there are any incremental changes to the processes that's where it can happen as long as the states have a role.

COMMISSIONER POWELSON: Mr. Chairman can I pick up on that?

CHAIRMAN MCINTYRE: Please do.

COMMISSIONER POWELSON: So in the New York rev model as I understand it here looking at my DER compensation manual -- it's LNP plus D correct -- that's the compensation metric applied?

MS. MITCHELL: Yeah, okay so we have a value staff.

COMMISSIONER POWELSON: Okay.

MS. MITCHELL: We have various components so.

COMMISSIONER POWELSON: Just say with me here.

MS. MITCHELL: Okay sure.

COMMISSIONER POWELSON: Your LNP plus D -- what if a jurisdiction says LNP plus G as we did under FERC Order 745 going back to what Commissioner Phillip's point of standardization how that would probably create a problem for us as we try to synchronize these resources in the market. Don't feel -- believe me I'm -- we can answer it next week okay, I get it.

But I just need to think about it because one jurisdiction's LNP plus D and another jurisdiction or the -- in the organized market is known as PJM with 13 states. Could it be LNP plus G?

And I think under FERC Order 745 it was LNP plus G is it not -- the treatment of those demand-side resources, no?

COMMISSIONER LEFLEUR: No it was LNP. The question was that it didn't minus the --

COMMISSIONER POWELSON: Minus --

COMMISSIONER LEFLEUR: As long as it met the net benefits test. We need a drink to discuss.

COMMISSIONER POWELSON: Okay, thank you that's why I wanted to go to the historian. But how would you all approach that I guess is my question. You know I heard Chairman Thomas talk about respect the regional differences which I wholeheartedly agree with you but --

CHAIRMAN THOMAS: This is also falls into the whole other state policy thing. The states are going to have different policies, they're going to have different cost impacts and there has to be a way to accommodate those different cost impacts within one market and that's a challenge.

And one broader point that I wanted to make on aggregation because there was some discussion in the first panel, you know, why do we need it, what good does it do? To me one of the keys that hasn't really been mentioned is what it is -- is it enables innovation in customer engagement.

To me that's a key point. You know we're going to have a sign over here that says, "Please turn off your cell phone." There's never going to be a sign in here that says, "You know, please refrain from participating in the wholesale markets, you know, pay attention to the meeting."

We need innovation in customer engagement where somebody can say, "I don't want to worry about all this stuff and hand it off to somebody else." That's the aggregator and we need innovation in business models and innovation in the technologies because people aren't going to sit here -- some will, energy nerds will, the people in this room will, but most folks aren't going to sit there and follow the LNP and figure out when to kick their battery on.

We need automation to do that and where you're going to get automation and investment in innovation is through aggregation.

COMMISSIONER GLICK: Mr. Thomas I wanted to follow-up on that for a second because I agree with you 100%. I'm just curious how earlier you referenced something I would call maybe, opt-out light, essentially it's to tell I'm sorry, DER, when you sign-up at the retail level you can't maybe, maybe you can't participate in the aggregated wholesale market.

And I wonder how the markets inform, if you had that approach because I think in the organization MISO state's comments submitted to the Commission in the NOPR proceeding here, I think it was referenced that the Illinois Commission, I think wanted to make a point about -- in the opt-out provision that we have with regard to the demand response proceeding, Order 719 -- that essentially, by allowing states to opt-out that essentially stunted innovation and stunted the development of markets.

I wonder if you could talk to that a little bit and how you're opt-out light approach could coincide with that.

CHAIRMAN THOMAS: I don't think it would stunt innovation because the states that want to do it want to do it and develop a model. And when they find value, other states are going to want to do that.

I think what Chairman Haque said, that's what everybody wants from a thematic policy view, but it's really complex to get there. And the question is who wants to tackle that?

I agree it would stunt growth if nobody wanted to tackle that but some states being willing to tackle it means we're going to get there, but the other states -- I know one state there's economic difficulties. They have too much generation because their load has gone down because of the economy.

They don't want to spend their limited staff resources because they're under budget pressure too, to study a problem of how we get more generation when they're trying to figure out what to do with the excess that they already have.

If that state has to deal with these complex issues of multiple strains -- I mean they agree with what -- I mean what Chairman Haque was a very good statement of the policy. Just when you push down into those details who's going to work through those complexities?

You're making -- you're giving states and out on working through those complexities while other states and in my view there's a critical mass of states that will do that in the micro area that's what I was trying to say -- does that make sense?

CHAIRMAN MCINTYRE: If I may, if the goal as we approach it in our storage proceeding is to ensure that in our wholesale markets there are no significant burdens to the participation of these resources in the markets would it amount to a burden, significant or otherwise, to have this state have the ability to say it can't participate in the wholesale market if you're over here -- participating in a market that we oversee?

CHAIRMAN THOMAS: To me it's the starting point not the ending point. To me let's start there so we don't force everybody to study these very complex questions and, and I wouldn't think that if I didn't know there were states that want to tackle these things.

And when they figure it out and they provide value then it will be easy for the other states to adopt that. I hope that's responsive -- it's a starting point, it's not the ending point.

CHAIRMAN MCINTYRE: Yes President Picker and let me note we have about five minutes left, quick to for the timing.

PRESIDENT PICKER: I'm not saying that we're eager to approach these things but because there is strong demand for opportunities to innovate and there is a lot of customer pressure to actually be able to approach these things that's going to talk about some of the steps that were involved in our ESTER proceeding which tries to make it easy for an ISO to accommodate energy storage in DER in their markets.

So again, they're outcome has to be market role changes and so we did a rolling initiative that could continue because I think we will get parts of it right, new technologies, new ways to apply technologies.

So Phase I, which was approved by FERC, being implemented in 2016, demand response enhancements to recognize behind the meter generation as statistical samplings, so that's the visibility. Storage modeling enhancements for submitting and for resources to self-manage their energy limits in state of charge so it gives them some ability to flip back and forth.

Phase II, which you approved in 2017 and is going to be implemented this year. ISO staff and the CPUC staff finalized a joint report on the multi-use application framework which was released in 2017 and we adopted, incorporated a gas indices into the net benefits test to calculation to reflect the energy imbalance market participants.

That's a regional constrained wholesale market -- we clarified power station power treatment for storage resources, we added three additional load baseline methodology options to better reflect performance of various demand response types.

And then currently this is the discussion we're now broaching on in Phase III is new bidding and real time dispatch options for demand response, removal of the single load-serving entity aggregation requirement and hopefully this will allow the emergence of system aggregators.

The measurement of behind the meter electric vehicle supply and load curtailment, assessment of multi-use application tariff and market design changes and then developing a process to identify use limited status qualification to storage resources which I hope gets at this -- eventually helps us to get this question on double compensation.

So it is fairly granular. We do have resources to approach this. More than anything else is we have a really strong will for the CPUC to work with the ISO to make this work. And that, more than anything else, is forcing our hands in these things and so you know, I'm not volunteering to do it and if New York can come up with the better way, we'd be happy to adopt their model.

But at this point we have a range of technologies that haven't been experienced, being used in ways that people didn't anticipate and providing values that are very hard to predict. And we're just trying to make sure that it works.

So if in fact, what the intent is of the Commission is to actually remove barriers for people to approach that, God bless you. We think the storage proceeding was a very good one. But I do think that it's going to be hard to come up with that magic one size fits all.

Someday the grid, at least in portions of California, will be plug and play. You can walk in, plug in your DER, it will be recognized. Whatever algorithms you're using to actually sell services to customers or to the ISO or to the utilities will be recognized and managed and then settled just in the way that people manage to do this and the MRT use and the wholesale markets.

We have a long ways to go and if you want to jump in and help us that's great, but I would recommend that you let us beat our head against those brick walls.

CHAIRMAN MCINTYRE: Thank you, Commissioner Place and then Chairman Haque.

COMMISSIONER PLACE: Thank you. Yeah, just quickly just a reminder to think we're trying to hold the tide back. I'm not sure we have that option but I was just thinking from the Pennsylvania PJM perspective.

These markets will substantially enhance the health of our PJM market whether it's energy capacity, ancillary services so I can't imagine an opt-out for us even if it's complicated to do and I know operationally yeah, accounting-wise, very complicated to do.

But I can only see us wanting to move in that direction because it does make our markets more healthy and that benefit is real. Particularly because if it enhances visibility and enhances connectivity and increasingly as we're seeing this, behind the meter, in front of the meter to me is some sort of an -- is a construct that somewhat is lost in this conversation, it should be, it's an archaic way to think about this, I think.

So the more we have that since we're getting more generation, getting more storage et cetera, on that distribution side for me the only future way forward is to participate in these markets and to encourage their use, thank you.

CHAIRMAN HAQUE: Chairman, Commissioners again thank you for the opportunity to be here. This is really fun to be part of the sort of policy piece of this so I'm very grateful again, for the opportunity.

So Chairman, to get to your question I think there's -- there is in my mind two sets of potential barriers. Those barriers that are attributed to the concept of distribution system reliability okay and if those are barriers that we put up to ensure that the D system remains reliable, then those are worthwhile barriers okay.

Because again, I don't think it's to anyone's benefit to experience D system reliability issues as a result of a marketplace that you create okay. Now the marketplace barrier piece -- now there will be a spectrum of where states sit on this and so you'll have states on one -- one end of the spectrum that will say, "Get off my lawn," and then you'll have states on the other end of the spectrum that would be very friendly to, to the opportunity.

So I guess I in just being sort of realistic about this -- you're going to create the marketplace that you -- you're going to create what you deem to be the ideal marketplace for these resources.

And what I think is really important to sort of hone in on, assuming that you buy the D system reliability barriers and the necessity of that, is what will be technically feasible actually for the aggregators to participate in the wholesale market for EDUs and RTOs to be interacting and coordinating associated with aggregator participation.

What level of day-to-day coordination is going to be necessary between the RTO and the, I call them EDU's -- distribution utilities in order to if there are -- if there are units -- if there are aggregated DER's dispatched, what does that look like for the distribution utility.

So I guess what I'm saying is when I'm charting out the policy roadmap, the reliability barriers there can be no sort, of from I think most state's perspectives, there can be no debate or discussion.

From the marketplace barriers perspective you may -- you may be in a position where you create the ideal marketplace and then you've got to figure out what is technically feasible between really, you know, four parties which are states, distribution utilities, aggregators and RTOs.

CHAIRMAN MCINTYRE: Acknowledging the criticality of ensuring protection of the distribution system as you've just described it -- do you agree with Chairman Thomas's point that if this DER market if I could use the term it's going to flourish, it needs to be ultimately consumer driven?

CHAIRMAN HAQUE: I don't know that if the market is to flourish it has to be consumer driven but the position that the state of Ohio has taken just generally on in the electricity -- in all of our spaces that we regulate is that it should be consumer driven.

So whether or not it allows for the market to flourish, I'm not sure but I think we are -- that the head space of the PUCO right now is that what we should be doing and the issues that we should be analyzing should provide net value to customers at the end of the day and let them hopefully through education, make the choices that they think are the most appropriate for themselves and for their businesses.

CHAIRMAN MCINTYRE: Very good thank you. I think it's appropriate we give the District of Columbia the final word.

COMMISSIONER PHILLIPS: Thank you Chairman, I'll be really quick. I just want to say I also agree that this should be and it is consumer driven in the District of Columbia. But I will also say -- and I like to say that it is the Commission, the Public Service Commissions and the FERC that stands at the intersection of new investment, new technology, prudent utility investment and what consumers want, so I'm set to go now.

CHAIRMAN MCINTYRE: Thank you so much and thank you again to all of you. This has been a most illuminating panel. On behalf of myself, my colleagues and the Commission I want to thank every one of you for your participation here today and we look forward to the follow-up with all of you.

We are now schedule for a break until 3: 15 so with that we are temporarily adjourned and please reassemble back here at 3:15 for the next panel.

(Break 3:04 p.m. - 3:18 p.m.)

MR. KATHAN: I'm going to have to ask one last time, could people please sit down and clear the room. If you have discussions take it outside so we can get this panel started. Thank you.

So this next panel -- Panel 3 is focused on issues associated with double compensation, same services -- many of the things we just heard in the previous panel and we're going to just dive down into some of the more details on that and there's a series of questions that we'll be asking.

But before I do that I'd like to introduce our panelists. We have Simon Baker from the CPUC, Michael DeSocio, from the New York ISO, Mihir Desu from the New Hampshire Consumer Advocate, Katie Guerry from EnerNOC, Ted Ko from Stem, Roy Kuga from the Pacific Gas and Electric, Marco Padula from the New York Department of Public Service and Paul Zummo from American Public Power Association.

Thank you for all being here. We're looking forward to your comments. I'd like to remind everyone that we intend to focus this Conference on technical and operational issues as described in the notice. We will not discuss other related matters including those that issue any pending proceedings.

And as I noted earlier, please note that we have a number of questions and sub-questions to discuss on this panel, and we'll probably have follow-ups so we may or may not you know, we have time to get through them all and we'd appreciate it if the panelists could keep their remarks brief. And now I'll turn to Kaitlin Johnson who will be leading the discussion for this panel.

MS. JOHNSON: Okay thanks very much Dave and thank you to all of you for being here. So we're going to jump into the first question. As you'll note from the notice the first question has two parts so I'm going to read both of them but please feel free to respond just to one or to both.

So given the variety of wholesale and retail services, is it possible to universally characterize a set of wholesale services as the same service? And if it is possible to characterize the same services, how could the Commission prohibit a DER from providing the same service to the wholesale market as it provides in a retail compensation program?

And please just lift your name cards if you're interesting in responding, Katie?

MS. GUERRY: Thank you very much, thank you first of all for having us here. We are very excited not only that you've taken up this topic as an individual panel, but that you've afforded us a commercial entity, a voice at the table, so we're very appreciative of that.

This is an important -- a topic that is very important to us. It is something that we address with our customers on a daily basis. So to answer your question yes, it is possible to establish a way to determine whether retail and wholesale programs should be considered the same service.

It is a way that can be sustainable over time and that can provide guidance on how to best pattern each state policy and FERC jurisdictional wholesale markets. A key element of determining what a same service is -- is what is the dispatch trigger?

So more specifically, what is the time of required performance? Is it the same? If it is then you have a same service. An example of a same service would be if you have a net metering customer that gets in the system where Chairman Haque alluded to this on the last panel, I swear I didn't pay him to mention it.

If you have a net metering customer that gets a fixed energy payment under a retail tariff, for every kilowatt hour that they've produced, a customer should not also earn an wholesale LNP payment for producing those same kilowatt hours, that would be the same service.

An example of something that is not the same service would be if a DER is registered at the wholesale level to be available in the event of a reliability event -- that customer could also be signed up at the distribution level to be available in the event of reliability.

Now both of those are availability payments for when there is a reliability event at either the bulk system or at the distribution level. However, the dispatch triggers are different. It is when there is a problem on the distribution system that resource could be dispatched but there is no reliability event at the wholesale level -- vice-versa that could happen.

And so in that instance while it might seem as though the availability would count as a same service it is not because there are instances in which they can be dispatched at separate times.

MR. KO: Hi thank you, Ted Ko, with Stem. Thank you again for inviting me to speak on this panel. I'd actually submit that the answer to the question is not that you can distinguish what's the same service.

The actual answer to the question is that for the purposes of preventing inappropriate double compensation, the question is not whether or not you have the same service. The question actually from the wholesale market point of view and from the Commission's point of view, is whether the compensation you're providing to the wholesale participation in the wholesale market is for incremental value that it was provided the wholesale market.

So the standard of review, or criteria, is to decide whether the provision and the providing of the retail service in some way affects the efficient clearing of the wholesale market.

If they are totally -- completely disconnected, then it's not the same service and you should be compensated for the incremental value that you're providing to the wholesale market.

If they are connected -- if for example, the energy dispatch that you're doing for the -- at the retail level, is accounted for in the market clearing of the wholesale energy market, then you're being double-counted right. But if it's not, if it's a completely separate thing then you're providing incremental value to the wholesale market and you should be fully compensated for it.

So as a more general principle, the question is not whether it's the same service in the way it's been defined in for example, the Commission -- the CPUC's multi-use applications, it's not whether it's capacity or energy or reliability or ancillary services. The question is whether the provisioning of those services has an impact on the efficient clearing of the wholesale market.

MS. JOHNSON: Great, Marco?

MR. PADULA: Thank you and I very much appreciate the opportunity to come here and provide some insight as to at least what we're trying to do in New York. And in New York we really make a distinction between services that are providing at the retail level -- that are being provided at the retail level versus those that are being provided at the wholesale level.

We think that there should never be double payment for the same service. We think there are ways to develop dual participation rules and standards to enable that to happen so that we can maximize the services that a DER can provide.

Are there times when it may look like a DER is providing the same service? Yes, but when you look at what the actual service is actually being provided like a distribution value, it may still have an energy value at the wholesale level. But there is a two different services being provided and we want to ensure that compensation for both of those services is available.

MS. JOHNSON: Thank you, I'm going to go to Paul and then I'll go back that way.

MR. ZUMMO: Okay, thank you. Paul Zummo with the American Public Power Association -- we're the trade association for the nation's 2,000 publically owned electric utilities and thank you for the opportunity to speak here.

I'm going to address, I think, the second part of your question although I think the answer to your first is largely yes. It's with some qualifications. I think the question though really is -- it's not whether or not we can avoid classifying something as wholesale or retail, but it's whether or not we should classify an entity or an entity should be able to be a retailer wholesaler at the same time or kind of mix and match.

I know this was addressed a little bit on the last panel but I would like to offer some of my thoughts on this. I largely agreement with Commissioner comments from Arkansas who said I think the states should make the determination whether or not there's the ability to mix and match.

Where I would sort of distinguish what he said is I think he alluded to the fact that it's safe that we will probably figure it out. And I agree that likely we will have the technology to figure it out but I think we need to figure it out first before we set the rules because I think there are a number of questions we have to ask.

My colleague from AMP mentioned some of the problems with some of the issues that small and medium utilities, especially municipal utilities will have. Some of the employee issues you just don't have the staff level to deal with some of the complications.

I would think even for large utilities and for all the mid-size utilities, all the other issues dealing with the technology. If we're going to have entities that are kind of going back and forth between the retail and wholesale markets, I think it necessitates metering beyond even AMI or at least I think you need to go beyond AMI.

You need to have communication channels at the AMI. The AMI itself will not be sufficient to sort of distinguish when an entity is acting or a resource is acting in a, you know, retail capacity or a wholesale capacity.

I also think and if we are going to have new technologies we're going to have to create new resources to be able to mix and match. I think again, this creates a burden for the medium and small utilities.

But also if I may talk about retail rates -- I don't know if I'm allowed to talk about retail rates in this forum. But I think we are entering a new paradigm where utilities are really looking at new types of rate design constraints, demand charges for residential and then some light design in the context of the distributed energy resources like now you have solar, you've got billing, buy all sell all.

And these entities or these utilities as they do this rate design whether or not it's in the context of DER or not DER, especially for medium-size, smaller municipal electric utilities, you know, there are margins for error when you are doing a loan analysis, when you're doing the cost of service analysis that set these rates -- there's a very small margin for error.

So what -- so I think the question that we have to answer before we proceed is really how is that going to affect these retail rate designs? How is this going to impact cost recover for these utilities if you enter this sort of this wild card where you have entities, where you have resources and can go back and forth between the retail/wholesale markets.

So I think that creates a real issue for cost recovery and I think that's something we have to consider before we go forward.

MS. JOHNSON: Great, thank you so much Paul, I'm going to move over to Simon and then go back this way, thank you.

MR. BAKER: Good afternoon and thank you for the opportunity to be here. So in California we've had some experience with demand response on the retail side trying to figure out dual participation rules there for demand response to simultaneously participate in say a capacity program and receive a capacity payment and then also participate in an energy-based program like real time pricing program, critical peak pricing, time of use and so forth.

And that took us some time to work through the very complex issues and it can be very contentious but you can figure out ways to parse out and demonstrate to the decision-maker that these really are distinct services that are being provided.

Now we have about 800 megawatts of storage that have come online or are pending approval. In California in the past four years so we're really kind of being pushed to look at the opportunities for storage commission -- our Commission looked at the possibility of creating value stacking opportunities for storage and that -- what led us to embark on this adventure of determining the multi-use application rules for storage participation in various different domains.

So it was really important for us to define a number of different domains. We had already established three grid domains. The customer -- the distribution interconnected them, the transmission connected which was through our target setting exercise that we've had for some time.

And then we added to those domains the wholesale market and the resource adequacy program which is a PUC jurisdictional program to provide capacity and reliability. And so then within that we also defined 20 distinct services with multiple services within each one of those domains. And those services were then further categorized as reliability and non-reliability services.

And so for us, the crux issue here about whether or not something is considered to be a single service, really our priority was to focus on those reliability service in making sure that we had a broad framework for rules related to that worked out.

So where we got to with that is that classifying them as reliability and non-reliability service helped us discern which combinations might be considered the same service and those would be potentially where you have two or more reliability services that are trying to be provided at the same time.

But there are examples for example, resources that can provide resource adequacy and also simultaneously participate in wholesale markets and receive payments for energy and so forth where those are both reliability services and then it's also allowable.

We also recognize that there are ways to, as was commented earlier, to parse this on a time basis. You can time differentiate the resource so that you can get multiple reliability services from the same resource. And we also recognize the possibility of capacity differentiated as well.

So our decision really is a very high-level framework but it's the building blocks from which to have a structured conversation to then do the necessary and hard work of working out the implementation details. And we have a working group that's established right now that will be coming up with a report by August of this year that's going to work out a lot of the tougher implementation details -- things like compensation for services, working out things like incrementality -- how do you determine incrementality?

And insuring that we have performance contracts that are adequately developed -- the metering measurement and settlement issues that are so important to figure out, enforcement provisions and any other changes that might be necessary to the PUC or CAISO jurisdictional rules.

So that's kind of been our approach. I can talk more later in further questions.

MS. JOHNSON: Thanks so much Simon, Michael?

MR. DESOCIO: Thank you, Michael DeSocio from New

York ISO. So in New York we have already implemented through our demand response programs -- a way for resources to participate both in the New York ISO's wholesale market as well as participate in a transmission owner utility based DER program.

Now we are able to do this because these are reliability-based programs, they're not economically-based and so they are requested as necessary by an operator. We can quantify what hours we asked for each resource. We can ask the utility to cooperate -- what hours the utility asks for the resource and then in the back-end make sure that we're not double-paying that resource because the utility is paying for it or the ISO is paying for it and we can unwind all of that in the settlement because we have all of that information after the fact.

But when we think about how we deal with DER's and we're thinking about involving the market models for DER's and letting DER's participate in multiple wholesale service regimes, that changes. And it becomes a little more difficult to just come up with a way to say for sure this service is indeed a wholesale service or a retail service.

And I want to give you an example of that. So you have a utility that has a DER on its distribution feeder and utilities ask that DER to help it out because the distribution feeder was loaded up and it needed relief.

That DER is now providing energy to unload that distribution feeder. That energy now meant that the ISO didn't need to dispatch it incremental megawatts of energy from another plant on the system.

How we deal with that service, or which service is causing what becomes very complicated to try to unwind. A path forward that New York is focused on is ancillary services just because it's clear for us.

It's clear that New York ISO is the one that procures the ancillary services, the operating reserves and the regulation service for maintaining the transmission system. And in doing so it's clear that an entity -- a DER that is providing that service can be paid for that service from the ISO but when we call on that resource to provide energy for say -- for example, depending on the program it's registered in that energy compensation may come from the ISO or may come from the retail program.

Now we have a program today that kind of does this but for different reasons. It's our demand side ancillary service program where we allow distributor resources to sell ancillary services but we don't pay that resource for the energy it's providing because it's a curtailment service.

We think of it more as reducing the load and therefore avoiding procuring the energy. But we already have that kind of set-up. I think we can extend some of those kinds of concepts to DER as we deal with the dispatchable way.

So these are some of the things that we're thinking about in New York and we are collaborating heavily with our utilities and with the Department of Public Service and we're testing these out through pilot programs so the ISO is executing a pilot program to try to figure out is there a natural decoupling or is there a natural coupling and where is that?

And we're trying to learn some of that with these kinds of programs.

MS. JOHNSON: Great, thank you Michael, Mihir?

MR. DESU: My name is Mihir Desu, I'm actually with a firm called Strategen and we represent a number of consumer advocates across the country. Today I'm here representing some work that we've done with the New Hampshire Office of Consumer Advocates on DER compensation.

I think it's an important distinction to make between services in compensation for different services because what we have at a lot of times on the retail level is we have an aggregation of services that are then within the rate design process, compensated together.

And you have programs like net metering which in a sense are compensating DER's for a number of services including energy as well as some other services that they provide to the grid.

So on the wholesale level when you make these distinctions and I think I agree with my colleague here from EnerNOC on having these services distinguished between dispatch signals, whether they be simultaneous or you know, at different time periods.

But I think what's important is determining how these services are compensated and allocation factors for not just DER's as a generator but also DER's as a load and how they impact the loads.

And one thing that we've done with New Hampshire Office of Consumer Advocates is looked at a model where we're looking at a VDR Tariff similar to what you have in New York where we're taking allocations from the wholesale market and applying it to how load is allocating those costs.

So for example, Henry mentioned earlier that in ISO New England, capacity is allocated on a one coincided peak factor right? So they look at the coincided peak in the previous year and allocate capacity costs accordingly.

So there -- I think are simpler ways for DER's to be providing value to the grid than just operating as a direct participant in the wholesale market. And if we want to provide a platform for a broad set of participants to participate in these wholesale markets, we need to reduce the complexity of how we're opening up the grid to DER's.

MS. JOHNSON: Great thank you, I guess I'll return to Katie.

MS. GUERRY: Thank you I just wanted to reply or respond to a couple of comments. The first is the topic of incremental value that Ted had mentioned as well as some of the other mechanisms to differentiate between services I don't think is inconsistent with differentiating based upon what the trigger signal is.

It is very similar to what Commissioner LeFleur was describing in the last panel in terms of value stacking where we had traditionally thought of capacity energy and ancillary services as products that energy resources could provide.

It has expanded much greater than that. There is a much larger stack of value streams that DER's can provide. And so understanding the distinction between them is very important. I also wanted to address the concept of DER's in and out sort of willy-nilly from wholesale and retail markets because it was mentioned here -- it was also mentioned on a panel earlier today.

I think that's sort of missing the point in terms of allowing DER's to have opportunities for dual participation. The idea here is to have complimentary programs, not ones that went at odds with each other.

And so if you prohibit dual participation, I actually have a greater concern that it's an either/or in or out of those markets perhaps on a yearly basis in terms of where those opportunities are which is not great for system planning.

Again, when you define about same service in a way that both the wholesale and the retail market participants understand what that is, you can then design programs that are complimentary to one another.

As the representative from New York addressed on the last panel state Commissions are not in the business of creating new programs that will cause their ratepayers to pay more money. And so if we at the wholesale level define what a same service is -- and this is what it will, you will trip being a same service if you violate this criteria by developing a program at the retail level -- that allows coordination and development of programs that complement each other rather than continuing to butt heads with each other, thank you.

MS. JOHNSON: Great, thank you. I'm going to move to Roy.

MR. KUGA: Thank you, Roy Kuga, PGNE, thanks for the opportunity to participate today. To the point that Katie made I get it's important to recognize that products and services can be provided both wholesale and retail and I think you heard I agree with the panelists about dealing with double compensation.

However, I think when you look at the physical aspects of what the products and services are versus the financial versus the operational considerations as well as the jurisdictional issues, you get into the complexities.

And so while product may appear complementary or maybe even the same product, when you get into settlements or operations and even under jurisdiction it's very challenging. In California we have a demand response program where DER's and behind the meter storage can participate for a reduction in load shifts and aggregation is working.

Again, it's taken a lot of time for collaboration and coordination amongst multiple stakeholders but it is a successful program. But when you look at a service like reducing demand -- there are intended elements related to settlements.

There is what is a charge debt and today in California the demand response program is charged all at retail rates, there is no bypass of the retail rate through wholesale charging. And it works. And people are clear with the products and I think we need to look at ways in which we can develop programs and leverage what already

exists to further implement multiple uses without double
compensation or retail rate bypass.

MS. JOHNSON: Great thank you. I'm going to move to Ted and then Marco.

MR. KO: Yeah thank you, Ted Ko with Stem. I wanted to also respond to some of the other panelists. In the overall beginning question for this first question was more around can you make broad definitional statements around same service.

And I think to highlight was Simon just said about identifying 20 different services that these DER's can provide I think that demonstrates is that there's no way to make blanket statements about this -- about what is and isn't double compensation in terms of at the broad service level.

You can't say you're providing this one and this one in all cases on all grids -- that's going to be double compensation or that isn't going to double compensation.

So I think that just goes to show that the -- it's almost impossible to make broad statements or broad prohibitions or broad rules about these and the other point being that what people have highlighted here is when we are talking about compensation and settlement it's an accounting question -- it's not a technical question. It's not a physical question, it's not an operational question, and it's not a reliability question. It's compensation right?

And so all of these things if there are situations where a resource is going to be inappropriately double compensated by whatever rules we define as inappropriate, the solution should be accounting solutions. They shouldn't be broad in or out, you can or can't do this, or you can or cannot participate in this market -- it should be accounting solutions first to net out the inappropriate double compensation without taking the participant all the way out of the market.

And so I think just in general from the Commission's point of view, from the ISO market's point of view, we're always looking to increase participation as much as possible and so they should be allowing as much participation as you were providing incremental value and doing the accounting to make that -- make that possible without just kicking people out of the markets.

MS. JOHNSON: Great, thanks, Marco?

MR. PADULA: Marco Padula, New York DPS. I just wanted to respond to something Katie said and just make sure I understand that the dispatch trigger -- I hope you didn't mean restricts the DER from receiving other values?

For example if a DER is being dispatched to provide T&D value then between 4 and 6 p.m. Monday through Friday in the summer time, it doesn't mean that it can't also get an environment value if it's a clean resource or also the energy value. I think, and maybe you can just clarify -- the trigger -- the dispatch trigger that you were referring to perhaps was to avoid the double counting of the same service, I think, but if you could just clarify that for me that would be helpful.

MS. GUERRY: Absolutely correct, yes I apologize if there was any misinterpretation.

MR. PADULA: Okay, thank you.

MS. GUERRY: I apologize if there was any misinterpretation. Again the concept that we are looking at with our customers and it's unique for every customer, is the ability to stack those values on top of one another rather than separate them out.

MR. PADULA: But then when you get into the question of are you providing the same service to two different entities, they are a wholesale and a retail, then perhaps a dispatch trigger would be the -- the rule that says you're only going to get the energy from this entity versus this other entity for example.

MS. GUERRY: Correct.

MR. PADULA: Thank you.

MS. JOHNSON: Great, thank you, Simon?

MR. BAKER: Yes, thank you. Just to add a little bit to what Ted was saying. You know if you look at those

20 grid services that we defined initially I mean there a myriad of permutations and combinations of those.

And so from a practical standpoint we see the details being worked out on kind of a case by case basis and that's going to be driven by what comes forward out of the marketplace and where they see potentially the greatest potential for innovation and for cost effective use cases.

So you know, for example, we already have PG&E has a contract with Tesla for a 20 megawatt project to do some distribution deferral and they will also likely be seeking participation in a resource advocacy markets and other markets as well.

So that's going to be the driver for us is to work through those issues. We're seeing a lot of interest in the distribution deferral services area and this is something new for us in California. I think New York was kind of an early adopter with the Brooklyn Queen's projects and I think there are other projects out there as well.

We're just getting started with that. The utilities are beginning to do pilot projects for DER deferrals of traditional distribution grid upgrades, but we have taken some initial steps to define four different grid services for that and within that process, incrementality has been one of the toughest nuts to crack.

But really the principal that we ultimately came up with was that as long as the DER provider could demonstrate that what they're providing is over and above what they may already be being compensated through another project and really the onus is on them to demonstrate that, then there should be ways to work this out.

MS. JOHNSON: Great, thank you, Roy did you want to respond?

MR. KUGA: I just wanted to add the comment that we're very supportive of the multi-use and the stacking of values and we're supportive of market structures that can enable that. But it's important to understand that there are going to have to be protocols and rules and we have to establish was primacy is.

Reliability for the ISO market, reliability for distribution grid, both reliability and we're going to have to make sure that people understand which comes first when push comes to shove when they're being called simultaneously.

And how do we deal with the complexities of potentially instruction to the same device to discharge from one entity and to charge at the other entity and if the meter reads zero, how do we deal with that?

So there are a lot of issues in terms of settlements, primacy -- that are being worked out. I think there's a great dialogue going on with the stakeholders represented here. Some of the stakeholders here are very active including with the DIAS, thank you.

MR. HERBERT: Along those lines I want to go back to something that you said earlier Mike and that was with respect to sort of demand response resources in New York both providing local reliability services to the utility but then also participating in the NYISO markets as well. And you said at the back end there's sort of an assurance that makes sure that the NYISO isn't paying the resource and the utility is paying the resource at the same time, that that's not happening and so I'm curious.

I guess can you just give us a little more detail about that process and how you decide who pays the resource and when those coincident dispatches actually occur?

MR. DESOCIO: Sure, so there are -- there are a few programs but the two that I'll reflect on are the special case resource program that the ISO administers and a local demand response program that kind of system administers.

And the resources can enroll or customers can enroll in both. We have to keep track of that so we need to understand that that's occurring. So up front we need to have some accountability up front about where these customers are enrolled.

Then when an event occurs, the utility , Con-ED and New York ISO coordinate the call -- so it may be that the New York ISO issued a call and that affected some of the response in the Con-Ed Program but because we initiated the call, we're compensating those resources for that call.

If at a similar situation Con-Edison issues a call, then we need to figure out how to dissect when the Con-Edison call came into place and whether there's overlap and then there are specific rules about which called first and what the reliability issue was that was being dealt with to unwind who pays for it.

So at the end of the day I think really what we're talking about is something similar and it's more about not preventing DER from providing services, but rather figuring out where the payment should come from -- I think that's what we're all here to talk about.

And, you know, and I think these issues are fairly complicated as Simon pointed out. When I get worried is when I hear about that there's a simple rule to say well when that service is invoked, then I know who should pay for it or I know that that service can be provided.

And where that becomes more problematic is in capacity markets where we're buying long-term availability and when we purchased that there's some expectation that that asset is going to be available to the ISO to manage reliability.

At the end of the day this is all about reliability and so when we think about this it's not that we're trying to put up obstacles for paying for the same service, it's more how do we make sure that the rules are clear and everybody understands them both the retail side and on the wholesale side so that when there is a need on the grid, the operators aren't questioning who gets access to that asset, because that's the last thing that we need on the grid.

We can't have utility operators and ISO operators arguing about whose asset it is. It needs to be very clear up front. Where I started was -- I think ancillary services -- at least in New York, could be a fairly clear way to start that trial because ancillary services the operating reserves and the regulation service are services that the ISO currently procures.

And so that could be an area that if you're looking to draw a bright line you might be able to draw one in New York just because of the way the New York market is structured and how we procure it.

But I think generally that's not going to be true and it's going to be difficult to unwind this without some detailed discussions about how we're going to execute it, who's responsible for what part of the grid that asset was called on for, and then if there are ancillary services being provided just because that asset was called on, which deferred needing to deploy other assets, how does that cost shifting and cost sharing occur?

So there's all of those issues that need to be dealt with and those are complicated and it's difficult to say that we're going to deal with them in a broad brush approach just because these programs are different everywhere.

There's several different retail programs that we would need to coordinate with and those programs are changing. So the best thing I can offer is that the ISO's need to collaborate with their state agencies and with the utilities to understand what these programs are so that we can develop rules and bring them forth to you all in a responsible way and in a way that we all understand what they are and can agree that the service being provided is being paid one way or another.

MS. JOHNSON: May I ask one follow-up Michael, when you look at that program to date, do you have a sense of the general amount of resources that were required both from NYISO and from Con-Ed to do that -- those calculations in the time that there was a call for those?

MR. DESOCIO: I don't have that number.

MS. JOHNSON: Okay.

MR. DESOCIO: But we can certainly file that in post-Conference comments.

MS. JOHNSON: Thank you. Let's see so I think we'll move on to Mihir and then we'll go down the line, thank you.

MR. DESU: I think one thing that we need to keep in mind as we're having this conversation is what is the ultimate goal of the DER aggregations? Is it to compensate DER's -- no, right? The ultimate goal is to either reduce or avoid wholesale system costs to customers or to the extent that, you know, we're increasing system costs is it commensurate with the reliability gains that we're giving to the system?

And I think sometimes that picture can be lost as we're getting into the nitty-gritty details. So you know, one thing that we're looking at is how you can actually keep that ultimate goal in mind when you're looking at these different services that you're providing.

And you know, one thing that you can do is look at how, you know, like Michael was saying, the differences between the services provided and the actual compensation mechanisms, how they're delineated. And like Michael said, that's kind of what we're trying to get at here today is trying to distinguish between the different services and the compensation mechanisms.

So one thing that we've been looking at is kind of from the retail perspective how are wholesale costs allocated to load serving entities and how can DER's offset that?

And is there a simpler way to do that than having DER's participate as a direct participant in the market? You know, different ISO's have different ways of calculating their reliability as well as, you know, vertically integrated utilities have different methods.

Do you look at the top 100 hours to see if you know, you're having reliability impacts or do you look at the top 50 or what not? And so when you have these different regulatory constructs how do you ensure that DER's are given a simple platform to actually provide these reliability benefits right?

So if you're -- if you're just looking at like the top five or the top ten, or whatever it is, how do you ensure that the DER's are available during that time and you know, like for example, ISO New England and PJM have different penalty factors.

And if you just have like a water heater a thermostat as a residential customer, are you really going to read up on all the penalty factor calculations? Do you even need to do that as a really small resource? Why should we have the same regulatory construct around the small resources as like a large 100 megawatt generator?

So I think, you know, coming to those questions as well is pretty important.

MS. JOHNSON: Great, thanks, so Katie, then we'll go down the line and then we're going to move on.

MS. GUERRY: Thank you and I apologize, I have to follow the rules. Katie Guerry from EnerNOC Now and Enel Group company. I wanted to comment on a couple of items that have come up and I apologize some of it encroaches on the next questions.

The first is Michael in response to your question regarding the two programs in New York. I think it's important to make sure that we're differentiating between capacity availability payments which is I'm going to pay you to be there versus the energy payment which is this is what you get paid for what you did when I called on you.

And so in that sense, this is what I was talking about before in terms of a distribution and a bulk system reliability DER program -- reliability program. There could be an overlapping dispatch -- there may not be but there could be an overlapping dispatch.

And in that event they should not get two energy payments -- that would be double compensation because in that situation they should not -- they injected but there's only one energy value for whatever they injected into the system.

But they should still both get both of those availability payments because they were available when needed. In terms of the difficulties that I'm hearing here is I'm hearing that it's difficult to figure out the economics, the accounting, even the dispatch protocols, but I'm not hearing anything that indicates that it's impossible.

In fact what we're hearing from California is it does require a lot of work but it is something that with all market participants can be figured out. And so I think that looking at things -- both the accounting as well as dispatch protocols, asking the ISO's to develop them in conjunction with the distribution utilities in their system, one would go a long way -- appliance filing say in coming back how would you establish the distribution protocols -- the dispatch protocols.

Something else I wanted to comment on just because it came up here and it was something that was addressed on an earlier panel which is value of aggregators and I think that what we're talking about here is one of -- just one of because there are multiple values of aggregators but one of the values of aggregators of DER resources would be that we bring together multiple customers who all have multiple capabilities.

It is our obligation then to optimize off of those capabilities knowing that we have multiple customers and multiple programs that we are enrolling them in. So the overlapping and differentiating capabilities of the customers in our portfolio -- that's our job to optimize off of that.

No different than say a retail supplier who has pipeline capacity or has to buy gas off of the spot market. You're optimizing what you have available to you.

So the final thing I wanted to comment on is I think you just brought up in terms of what is the ultimate goal of what we're trying to do here? And I think that that's a really important question.

The goal here is not to jam DER's into one market or the other because the reality is they're coming. And so it's not to make it easier -- the objective for me here is how do we capitalize on the reliability that these resources make available at both the distribution and the wholesale level?

This is -- we should be coming together to devise a system, a set of rules that allows them to provide the reliability benefits wherever they are valued most -- at that time whether it is at the wholesale or the distribution levels.

Again, I just thought I wanted to reiterate that the goal here is how to I think not whether to, because they are coming and so we want to make sure that we capitalize on the reliability value that they bring.

MS. JOHNSON: Great, thank you Katie, Ted?

MR. KO: Ted Ko, with Stem. I think Katie just said most of what I was going to say anyway. But I do want to look at it from -- and this shows up in a lot of Stem's comments in these situations is -- we're here speaking about this from the Commission's viewpoint of the goal of the Commission in this is -- in my mind, ultimately, to increase participation in the markets.

It's like getting these resources that are there, the more participation you get in the markets, the more efficient outcomes you get, the lower the costs for everybody. And so that really is the ultimate goal and if you want to remove barriers to that participation where this was asked actually on the last panel -- you know, are these double compensation questions, are these opt-out type provisions or prohibitions, would they be a barrier -- and clearly yes.

It would be a barrier if you had these hard prohibitions on this case so to go with again with what going off of what Simon said earlier about a case by case basis, I think that's the approach that we should be taking here in general about these rules is like the default is we allow these resources to participate.

We evaluate on a case by case basis in which we have to not curtail their participation but, you know, cut down the compensation related to that participation if that's based -- if there's some inappropriate double compensation going on.

And it's only inappropriate from FERC and from the Commission's and the wholesale market's point of view if it affects the wholesale market right? If it's some double compensation for some other reason that has no effect on the clearing price of the wholesale market, then it's not under the Commission's purview to restrict or make rules about that.

It's under -- if the local utility would prefer that you not get double compensated, they can take it out of their side of the program rather than the wholesale market taking it out of their side of the compensation right?

So I think there's very clear jurisdictional questions, jurisdictional lines around the transaction where the Commission would make the rules on the compensation that's provided for the wholesale service and whether or not to discount that or reduce that based on double compensation versus if there's double compensation that's going on in the retail side that somehow is distorting the efficient outcome of the retail market then it's the states and the local authority's role to net that out and do the accounting and pull that out of the system.

MS. JOHNSON: Great, thank you, Roy?

MR. KUGA: I just wanted to address a comment Katie made. First of all I would just say that we see the value of aggregators and the role that they play and it helps certainly realize greater GHG reduction, reduce costs for a system, improve renewables into the grid.

So we see a lot of value and they really do enhance reliability. A comment that concerned me was we're going to optimize to see where the value is greatest. And I would say when we deal with reliability, you know, the value is uncompromising in terms of what is established as the primary reliability need.

And we cannot sacrifice that primary reliability need because there's a greater value for reducing your demand charge and that's the concern I have with the comment.

MS. JOHNSON: Great, thank you, Marco?

MR. PADULA: Yeah, Kaitlin, you asked if we had any information about the overlap of the program calls. I happen to have some historical information from 2011 to 2015. The Con-Edison Distribution Load Relief Program and the ISO SER Program were called in Zone J for a total of 236 hours.

And of those hours, only 14 were their overlap calls. So for that period of time, 6% of the time there was an overlap with the ISO call. But that just -- in my opinion, shows you how there is a, you know, a different service being provided that the distribution utility relies upon versus what the wholesale bulk system is relying upon as well.

MS. JOHNSON: It's really helpful and I'm curious given that there was that potential for overlap how many resources in terms of personnel were required to monitor or to assess that because one of the concerns was how many resources would be required of the utility or an ISO to deal with that -- do you have any sense or that wouldn't be numerical necessarily?

MR. PADULA: I know that the Con-Edison folks who run the program, it's not a very large group of individuals -- probably a handful that are running the demand response programs.

MS. JOHNSON: Okay.

MR. PADULA: And I'd like to say how many are on his side but it's not a huge group of people that are necessary to do that kind of monitoring.

MS. JOHNSON: Great, well this is actually very fortuitous because the second question addresses this in particular. We have already discussed the first part of it but I'd like to just read it and then publish your responses more to the affected part of it.

So in Order 794 the Commission states that an RTO or ISO may place appropriate restrictions on any customer's participation in an aggregation of retail customers aggregated response bid to avoid counting the seam demand response more than once.

How have the RTO/ISOs effectuated this requirement and otherwise insured that double response participation in their market is not being double counted? It's very tough to provide a bit but the second part of the question is what would be the advantages or disadvantages of taking the same approach with DER aggregations that the RTO/ISOs have taken with demand response instead of the approach proposed in the NOPR for preventing double compensation of the same service?

Alright so let's start with Simon and then Michael.

MR. BAKER: Yeah, thank you. So since 2012 California has painstakingly implemented rules to allow for direct participation of third party demand response resources in CAISO markets.

And we've done that to foster innovation and market competition and hopefully grow the demand response resource in California which we have not seen grow a lot in California and that's one of our objectives.

And so we've done that through a combination of rules relevant to the CAISO participation model, mainly, approximate demand resource and RDRR and then our own direct participation rules which we call Rule 24 and 32 and these rules are set up to insure that there's no double counting.

So the third part DER resources, they register at the CAISO under PDR or RDRR and then they have to comply with the CAISO's eligibility requirements which involve things like being located within one sub-lap, serving -- being served by only one load serving entity and so forth.

And then the CAISO does a review that ensures that the customer counts in the resource are not registered in other DR resources. In this pretense, the same DER resource from being paid twice for the same load reduction.

The CAISO also notifies the LSE of a pending resource registration and then the LSE must review the registration to verify that the accounts are customers that they serve and if the LSE is a utility, the utility is also then required to ensure the accounts are not in a utility-operated DER program.

Again, to prevent double payment and they do this -- they're required to do this review under the PUC's Rule 24 within specified timeframes so that this can move along expeditiously. And if the CAISO discovers that there's an account that's been registered with another resource, it's held up until that gets cleared up and then there are rules for settlement using baseline methodologies and so forth to ensure that there's a, you know, an incremental value that's being offered through that transaction.

So that's kind of how those rules are set up in California.

MS. JOHNSON: And one follow-up related to our earlier discussion as well. When you're looking at the multiple use project and you're thinking about the fact that those 20 services may have to be assessed on a case by case basis -- do you think that there's going to be a higher administrative cost than you saw with what you needed to do for demand response?

MR. BAKER: I don't think so. There's going to be a high administrative cost for that let's say -- first use case that comes through the pipeline that's of interest to the market.

MS. JOHNSON: Okay.

MR. BAKER: But then once that's been higher, once that's been you know, hammered out, then you know, that can grow and flourish and other market participants can use that same model.

MS. JOHNSON: Okay.

MR. BAKER: Until such time as some new use case or combination comes along and then we'll be, you know, back to square one having to go through the painstaking process of working out all the specific details of that use case.

MS. JOHNSON: Okay, great, thank you. Michael?

MR. DESOCIO: Thank you Kaitlin. So to your question about whether or not the approach that we employed for DR could also be extended to DER I hesitate to suggest that that would be a way forward and the reason is that the demand response programs that we do this for -- programs that have long notification times, they're manually activated, there's lots of time for operators to coordinate the call, understand and communicate between the utility and the ISO on what's happening and why the calls are being executed.

And then there's a long lag time at the end to get all the data from the aggregators and the demand response providers to actually facilitate the settlement.

If we were to do this for DER's in New York were visiting DER's are going to participate more as a dispatchable resource just like a traditional generator -- now we're talking about dealing with coordination implications between the ISO and the utility and you'd have to come with ways to automate a lot of that.

I'm not suggesting it's impossible but certainly it's challenging and I think a better approach that the ISO has right now in place for how we manage the fleets with the utilities is an approach where the utilities in the ISO were together and if the utility has a need for dispatching that resource, they can reach out to the ISO and ask for that resource to be brought online.

So that's, you know, a local issue they can use the resource -- now that there's coordination between the ISO and the utility that communication is taking place, the ISO understands why the resource is on and the compensation and cost allocation is all dealt with in the wholesale program.

I think when you can start to think about ways to expand that to retail program -- other retail program uses but I think as Simon suggested, it's going to take that first use case to really think through all the interactions and who should be paying, where should that payment come from.

But once that's done I think, you know, that process could be then automated and the protocol solidified so that the operators understand who's doing what and when.

MS. JOHNSON: Great and thank you, Katie?

MS. GUERRY: Sorry, Mr. Desu, if you would like to go first.

MR. DESU: I just wanted to respond to one comment that Ted had made about, you know, increasing the amount of competition leading directly to reduce costs. I think, you know, there can be times where that's not the case especially with DER's when if you have large metering and telemetry requirements that especially those costs are borne on ratepayers, you might -- that might not be a sufficient condition because those metering and telemetry costs may, you know, out cost the value that the DER's are providing.

Like in -- as an example, you know, this is a vertically integrated example, but I used to work at Portland General Electric and one thing we were trying to figure out with our net metering customers is how to monetize the rec values and in order to do that you need to have generation meters on each of the solar systems.

And the costs of those meters outweighed any value that we could have ascertained from the recs, so just one comment there. But going back to your question about, you know, the different models that DR's can provide and is there a similar model to demand response that DER's could participate in.

And I think there's a couple things that have been implemented lately in PJM and ISO New England -- you know, the pay performance rules that can really detract from DER's actually participating in the market.

And I know this is not the exact forum for that but it just goes back to that complexity about how you can have DER's participate in the system and if they are direct participants, these pay for performance rules really necessary?

And you know, one thing that DER aggregations can provide in some cases is non-wire alternatives. And, you know, FERC Order 1000 has kind of jump-started this process but in a lot of the ISOs you don't necessarily have a valuation criteria looking at how a non-wire alternative which in a lot of times can be a DER aggregation can cost effectively compete with a transmission alternative.

And I think FERC can have some authority here to kind of implement that process where you're actually having a transparent process to look at the differences between these two resources.

MS. JOHNSON: Thank you, Katie?

MS. GUERRY: Katie Guerry for EnerNOC, excuse me. So question 2 which you had addressed. I had taken the first question to be not should we utilize -- should we utilize the exact measures that the RTO's employed under 719 -- I took the question to be should we utilize this concept where we have an obligation on the RTO's to put a mechanism in place.

So the direct answer to that question is we think that is the better way to go. Listening to everything that Simon has described, it is a difficult thing to do. It is undoubtedly a difficult thing to do and something that needs to be very thoughtful but I'm going to quote Vice Chair Place who spoke at the last panel and he said, "By forcing either/or we're fixing the here and now, but we're not planning for the future."

And so it is incumbent also comments that Commissioner LeFleur made this morning about you know, "Let's skip past the next 10 years and just figure out how to do this, you know, the right way the first time." I think that's where we're at right now is yes -- it's difficult, it's hairy, it's messy, but these are resources that are coming on and they provide a tremendous amount of reliability and resilience value to both the distribution and the utility systems.

So if we did go with the approach that was spelled out in the NOPR, outright prohibition -- our concern, first and foremost, it would negatively impact reliability and resilience of both systems -- of both the transmission and distribution systems.

Because what you'd be doing is forcing DER resources to choose between one or the other. You're essentially saying to one system, "You can have this physical resource to meet the constraints on your system but the other system you can't use this physical resource that is available to you." That is a problem for reliability that you're not making those resources available to both systems.

We also feel that it will negatively impact competition and innovation, developing new services to develop system needs. By working in collaboration, by having an understanding between the services offered at the retail level and the services offered at the wholesale level, that facilitates innovation in a comfortable space that there will be a home for what you are working on as opposed to a fight about where you are going to be registering your resources.

So it would be a problem for innovation and for competition. Finally, I had mentioned this before but it would be completely contradictory to the efforts that have been underway to identify synergies and harmonization between wholesale markets and state policy.

I'll give an example in my home state of Pennsylvania, of very complementary dual programs that are in place at one time which is Act 129, it's for DR but it's a program that is in place in Pennsylvania. It is a peak load management program.

It's Commonwealth of Pennsylvania has said it is a policy objective of ours to manage the peaks of our systems down and we would -- we have a policy that we would like to advance that and so they have a DR program that is centered around that.

Those customers can also participate in PJM's capacity program to be available as an operationally dispatchable resource in an emergency or pre-emergency event. Those are very complementary because those DR resources -- it gives DR resources that have the ability to reduce in the summer, they have an option of where they can participate or it is providing resources who can provide with year round, annual capacity capabilities as well as discrete weather-driven summer capabilities.

They can then participate in both programs because they are solving two different things. Peak load management which is the policy of the Commonwealth of Pennsylvania and the availability of operationally dispatchable resources in an emergency or pre-emergency event -- those provide a nice complement to each other in the Pennsylvania -- in Pennsylvania in the PJM for providing multiple options to states in a complementary way.

If we had put a prohibition on dual participation, again that would have impacted reliability and created friction between states and further friction between state and wholesale policies.

MS. JOHNSON: Thank you, we'll go to Ted and then Roy and then we'll move to our next question.

MR. KO: Ted Ko with Stem. I wanted to work off of what Simon -- the example that Simon brought up about Rule 24 and dual participation because it's actually a really, really good example of the inefficient outcomes of too broad of a rule.

So the Rule 24 as it is designed I think in 2014 prohibits third-party DR providers who are participating directly in the wholesale markets, or the customers that are using DR aggregators to participate directly the wholesale markets to also participate in another utility DR program.

And so that may be appropriate in the sense of there's another utility DR program that's having the same capacity value that you're direct participation in the market is having at the same time.

But it's also currently set up so that you can't -- the customer cannot also participate in like a critical peak pricing tariff, which should -- which by all means should be able to be -- you should be able to do both right.

And so because of that restriction that occurs, customers who want to go participate in the wholesale market decide not to and aggregators like us who are going to sign-up these customers to pull them into the wholesale market, can't do that because there's restrictions there.

And so it's a rule that was done long before a lot of this multi-use was figured out and that needs to be updated. The other -- the other part about that is also that rule also prevents what also Simon mentioned earlier about capacity differentiation.

The idea that a single resource for example, a one megawatt battery could bid 700 KW into the wholesale market and 300 KW into a local distribution reliability program and there's no overlap, there's no problem with that -- there shouldn't be any problem with that because capacity is differentiated fully available to both, it's not possible to Rule 24 right now.

And so it's the same kind of idea as like these rules that were set in too broad of a case as to be general across all the different services don't hold up over time and so again it goes back to the case by case process. It should be -- the rule should be let the participation happen and then if problems come up, double conversation problems come up, then set rules to restrict that, but not the other way around.

MS. JOHNSON: Great, thank you Roy?

MR. KUGA: Roy Kuga, Pacific Gas and Electric. To your question about the advantages and disadvantages -- hopefully it's not a binary decision. I think we should have each jurisdiction figure out what works and as Simon and Ted and others have mentioned that we've invested a huge amount of resources and brain power through a collaborative process.

We have a platform that is an enabling platform that allows behind the meter storage aggregations to occur, as well as demand response. Can it be better -- yes? Ted mentioned, yeah, there are moments that could be better.

But I think to Katie's point about promoting innovation, competition and encouraging greater participation we already have over 500 megawatts participating in our service territory or for what thousands and thousands of customers.

I think it's a working model. We've invested a lot of resources and coordination with the ISO and the multiple stakeholders. The multi-use issues still need to be worked out as we look at different use cases and but when you look at some of the major obstacles in terms of metering -- behind the meter charging, interconnection, data access and privacy -- a lot of this is worked out and so we ought to leverage what's in place and it's working in the ISO market as well.

MS. JOHNSON: Great, thank you, I'm going to move on Simon but you will have time to speak in just a moment. So I think this is largely building off our conversation to date. From your all perspective, what are the other options that exist besides the NOPR's proposed limits on dual participation to address the issues associated with the participation of DER's or DER aggregations in one or more regional compensation programs or another wholesale market participation program at the same time it participates in a wholesale DER aggregation?

We've heard some of that that perhaps the ISO/RTOs should lead in creating rules or perhaps it should happen on a case by case basis, but just curious if you could add any more thoughts on that and thank you. And Simon do you still want to --

MR. BAKER: I just wanted to speak to the -- what seems like an emerging proposal to have prohibition on NEM resource participation and wholesale markets and that's not an issue that we've taken up yet at the PUC.

And it's something that as we said in our NOPR comments, NEM and rate-payer fund retail programs are state jurisdictional matters. We have plans in our distributing energy resources action plan to take up this issue in 2018 concerning the potential eligibility of NEM resources to participate in the CAISO's -- through the CAISO's DERP Tariff.

We appreciate that the FERC approved CAISO DERP Tariff left it to the local regulatory authority to make this determination and we recognize that, you know, that it could be a stretch to imagine situations in which NEM resources could demonstrably be shown to be incremental and measurably distinct and therefore eligible for dual compensation.

You know I'm thinking about -- I'm thinking about smart inverters for example -- smart numbers are bringing to the floor a number of different capabilities that are new and you know, we're dealing with an issue right now in California where a frequency-watt capability in our Phase 3 smart inverter process is looking at ways that, you know, small DER resources with smart inverters could be able to support stabilization after a frequency event, a frequency disturbance.

You know one can imagine that, you know, if that resource -- if a resource didn't have that capability before but then and it's participating in NEM but then a smart inverter is installed to be able to provide that capability okay, they're a NEM customer but now they're providing potentially an incremental service there that wasn't there before.

So that's why, you know, we urge caution in terms of any blanket product prohibitions because there could be some scenarios in which it's justifiable.

MS. JOHNSON: Great, thank you. I'm going to go to Paul and then I'll go back down the line.

MR. ZUMMO: Alright thank you, Paul Zummo, American Public Power Association. I think where our organization stands is that we largely agree with the NOPR's prohibition but if we were to move past it if some of the operational concerns that I expressed initially were addressed and we moved to a different compensation wheel out, some back and forth, I think I just have some general principles that should be kept in mind.

I think predictability is very important. I think we have set clear rules and distinguish between services and compensation for those services. I also think that anything we do has to be fairly automated.

As you mentioned before I think, especially with medium and small utilities, you know, there's just a limited staffing there's just got to be -- the mechanisms have to be fairly automatic to not strain those already limited resources.

And I also think the authority of the local utility local, the local ERIA's have to be respected I think a sort of compensatory program, you know. I mentioned retail rates before I also think we have to respect that local utilities also have their own unique programs meant to encourage the ER's and energy efficiency and I think we have to work -- multiples have to respect those unique programs.

MS. JOHNSON: Thank you very much. I'll move back this way so I think who's next, Michael?

MR. DESOCIO: So thank you for the opportunity again and as we've been working through a lot of these questions in New York, in the New York stakeholder process there, so the stakeholder process and the DPS, and joint utility stakeholder process and as we think about it there's a couple of things that I just want to point out so that you all are aware of them.

One of the issues that we're working through is can we allow a NEM like rate to work with an entity that's providing say wholesale regulation -- regulation service or operating reserves, so that's something we're going to test out.

Another thing that we're working through is where we're looking to understand better what are the system requirements of capacity? What is that amount of duration that we need capacity for on the grid? What are the hours that we are buying that capacity for -- to help inform that product and help us figure out where we're going to go next.

But one of the things that we -- we don't know how to deal with yet and we're thinking about is what happens when an entity signs on to an ISOs services tariff? When they sign on to the services tariff they take on the obligations of that service's tariff.

And the way the service's tariffs are structured right now, there's not this halfway in, halfway out model so we need to develop that. And I think that is going to be the hardest part in this whole thing is what are those clear rules to figure out when it's appropriate to be opting in to the services tariff or opting out of the services tariff -- and that becomes problematic because a lot of the rules that we have in place are because we've had situations in the past in the markets that caused us to develop the rules we have in the services tariff.

So it's going to take us some time to work through that. I saw all that -- I'm an advocate that we can figure it out and I'm not an advocate to create a uniform blanket that we can't do this. But it is something that is going to take us some time and some real thoughtful discussions on how to do that in a way that is -- can be practically administered by us, by the MMU's, as well as can be understood by the entities that want to actually use it so thank you.

MS. JOHNSON: Great, thank you, Mihir?

MR. DESU: So I think there are simpler, more effective ways that we can appropriately compensation DER's for the services they provide. I mentioned earlier like the value of DER Tariffs that we're -- we're trying to put together in New Hampshire.

In fact, we're -- stakeholders have come together, commissioned by the PUC to actually look at how a value DER Tariff on the load-side would compare to a Market Value Tariff or just market value participation.

And this method can provide some simplicity in those price signals that the DER's really want right? So, if we're allocating these different costs from capacity markets, energy markets and ancillary service markets to load in a way that is -- is simple to understand, why can't DER's just respond to that?

And you know, New York has done something similar and I think the distribution value is more of a state and distribution utility issue. California has done some interesting work with the location on that benefit analysis.

I know Central Hudson in New York has done some interesting work there with -- it's like called an LCCF. So I don't necessarily think FERC needs to intervene there but making sure that these wholesale market values are compensated in a simple and effective manner is I think where FERC can really help the system.

MS. JOHNSON: Okay thank you. We've got about 10 minutes left so I'll go down the line if everyone could keep their remarks short please, Katie?

MS. GUERRY: Thank you very much, Katie Guerry, from EnerNOC. So quickly, the first question in this -- in question 3, we've discussed multiple options here but yes, there are other ways than outright prohibition.

We as -- it was mentioned on an earlier panel that utilities are seen as the gatekeeper -- we actually view utilities as more of a facilitator and so we think that there are multiple mechanisms that can be implemented with the RTO Tariffs that can allow them to work with the utilities as facilitators of the integration of these resources.

In thinking about the complexity of -- and everyone has been talking about in terms of how do we figure all of this stuff out -- I'll just give an example of a mechanism that PJM had implemented for demand response.

When it was originally implemented during the registration process there was layers in which the utilities had to sign-off on customers participating in the demand response program. Over the course of the years we learned that those multiple layers of checks were unnecessary and so as a stakeholder community we voted and scaled back those rules because we discovered that the unnecessary complexity was actually bogging the process down.

And so I just offer that out there as sort of a lesson learned in terms of it can done and maybe it's a little bit simpler than we think that it is. And also, not only do we think that there are ways that we can do that, but we feel that it is incumbent upon us to figure out ways to allow dual participation because that will force the communication and the coordination at a whole other level than we've ever seen before between the RTOs and ISOs and the utilities.

Again, I'll go back to the Act 129 example when Phase 3 was implemented last summer, the collaboration between the PJM DR group -- each of the utilities in Pennsylvania and the vendors that operated under Act 129 in the months leading up to the start of Phase 3 of the DR in Pennsylvania under Act 129, it required a lot of coordination discussions and an understanding of what information was needed.

Now we figured that stuff out, the objective is then we don't need to worry about that next year at the start of the registration, the start of the next delivery year. So I just bring that up as an example that again it's complementary, it's been a forcing function to integrate communications and dispatch protocols.

MS. JOHNSON: Great, thank you, Ted?

MR. KO: Ted Ko, with Stem and I'd just like to again kind of flip this question on the head as I do with question 1. Again, looking at it from the Commission's point of view and their goals for increasing participation and efficient outcomes of the market, the question is not how to -- the Commission in a final rule would develop other methods for prohibiting dual compensation -- double compensation.

The question really should be that the Commission is -- takes the approach of allowing participation and the rebuttable presumption is that it's not being double compensated until somebody proves that it is.

And so it's incumbent on the states or even the local ISO to demonstrate on a case by case basis why this particular situation is inappropriate double compensation along the lines of -- and the criteria for that is does it negatively impact the efficient outcome of the wholesale market?

If they can then prove that, then it's incumbent on them to on the parties that to then say this is the accounting methodology in which we will resolve this inappropriate double compensation.

And those should all be the steps that should be taken before any concept of a prohibition should be made. Prohibition is only appropriate if there's either no way to mathematically take it out or it's full complete overlap and you'd have to take out the entire compensation because it's -- it's complete overlap.

And that would be the only criteria in which you could then justify an actual prohibition, but a prohibition should be the last resort.

MS. JOHNSON: Great, thank you Ted, Roy?

MR. KUGA: Roy Kuga, Pacific Gas and Electric. With respect to the metering as we know many states have many different flavors and nothing is static. And as we look at the prohibition I think it's important to understand that the net metering structure can evolve over time and if we look at the unbundling or disaggregation of what the costs are unavoidable, what are TND or group supported and what are market based -- I think we could come up with a structure where compensation can occur to the DER behind the meter resources, but we need to have the right kind of market signals occurring both on the retail side through the unbundling of the rates along with the wholesale market transparency, thank you.

MS. JOHNSON: Thank you, Marco?

MR. PADULA: Yeah, Marco Padula from DPS. So we would agree that prohibition should not be the way to go. The one big suggestion that we would have is you really should look at this as a multi-phase process over time to enable DER technologies to evolve.

The DER technologies that we see today are one flavor, what we're going to see tomorrow or five years from now is something we can't even imagine. So what we've done in New York, we've established certain tariffs and contracting mechanisms to try to value those resources that we have today but as we move forward we're envisioning a much more dynamic market through the development of a DSP at the retail level that would then you'd have to develop market coupling mechanisms between the utility DSP's and the ISOs.

That's something that we see will take place over time. So the message that I want to -- the last message that I want to get across it's really a phased approach but we don't want to stop what we're doing today and wait for that -- that future vision.

We believe we can start moving in that direction and enable the DER technologies to evolve over time and take advantage of what is happening instead of just waiting -- you know, a wait and see approach.

MS. JOHNSON: Great thank you, we've got a couple minutes, Simon do you have a few last remarks?

MR. BAKER: Yeah, I just wanted to say and perhaps this is stating the obvious but the collaboration that we have had in California with the California ISO to implement these rules has really been essential.

We've had -- we've done joint roadmaps together, we've done joint staff papers -- actually the multi-use application decision was based on a joint staff paper. We've done joint workshops and so that's really been essential to be able to have those robust conversations to be able to work this out.

Also, just having decisions like we passed on MUA, providing a broad framework and a structure within which we're working out the details -- we think that's a good first step for local jurisdictions in concern with their ISOs and there's no substitute for the time that it takes to work out these details.

And we think that will probably be in front of a meter use cases are going to be the first to get worked out because the behind the meter has just a lot of really tough details to work out.

MS. JOHNSON: Great, thank you. I want to thank all the panelists. I think brings us to a close. I think Dave has a few closing remarks.

MR. KATHAN: I also want to thank -- it's been a wonderful panel and it's been a great day. I think we've covered lots of great stuff so we'll be adjourned for today. I want to mention tomorrow we're going to start at 9 a.m. and we'll have -- cover four different panels over the course of the day.

And tomorrow we'll have a little different focus. We'll be more focusing into some key reliability and operational issues so there'll be two panels in the morning looking at some of the issues associated with a bulk power system.

And the afternoon we'll be focusing on issues associated with coordination which we've been hearing throughout this discussion already today. There has also been some reference to post-technical Conference comments and I just wanted to note the Commission will be issuing a notice in the near future, establishing a timetable and procedures for these comments.

So with that enjoy your evening.

(Whereupon at 4:46 p.m., the conference was adjourned.)

CERTIFICATE OF OFFICIAL REPORTER

This is to certify that the attached proceeding before the FEDERAL ENERGY REGULATORY COMMISSION in the Matter of:

Name of Proceeding: Distributed Energy Resources

Docket No.:

Place: Washington, DC

Date: Tuesday, April 10, 2018

were held as herein appears, and that this is the original transcript thereof for the file of the Federal Energy Regulatory Commission, and is a full correct transcription of the proceedings.

Larry Flowers

Official Reporter