UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

Technical Conference on Modernizing Electricity Market Design: Energy and Ancillary Services in the Evolving Electricity Sector

Docket No: AD21-10-000

TECHNICAL VIDEO CONFERENCE

Federal Energy Regulatory Commission

888 1st Street NE

Washington, DC 20426

Tuesday, October 12, 2021

9:00 a.m.

Welcome and Opening Remarks

Panel 1: Incenting Resources to Reflect Their Full Operational

Flexibility in Energy and Ancillary Services Offers

Panelists:

Dr. Nicole Bouchez, Principal Economist, Market Design, New York Independent System Operator, Inc.

Joseph Daniel, Manager, Electricity Marks, Climate and Energy Program, Union of Concerned Scientists

Tom Kaslow, Vice President, Market Policy, FirstLight Power, Inc.

Sherman Knight, President Competitive Power Ventures

Karen Onaran, Vice President, Electricity Consumers Resource Council

Greg Sorenson, Manager, Market Surveillance and Mitigation, Southwest Power Pool, Inc.

Dr. Catherine Tyler, Deputy Market Monitor, Monitoring Analytics

Panel 2: Maximizing the Operational Flexibility Available from New and Emerging Resource Types

Panelists:

Betsy Beck, Director, Regulatory Affairs - Central and Western U.S. Enel North America, Inc.

Jason Burwen, Interim Chief Executive Officer, Energy Storage Association

(Cont'd.)

Mike DeSocio, Director, Market Design, New York Independent System Operator, Inc.

Brian George, Director of Strategic Policy and Government Affairs, Electric Power Supply Association

Dr. Walter Graf, Senior Director of Economics, PJM Interconnection, L.L.C.

Dr. Nikita Singhal, Technical Leader, Grid Operations and Planning, Electric Power Research Institute, Inc.

Panel 3: Revising RTO/ISO Market Models, Optimization, and Other Software Elements to Address Operational Flexibility Needs

Panelists:

Dr. George Angelidis, Principal, Power Systems and Market Technology, California Independent System Operator Corp.

Dr. Erik Ela, Program Manager, Electric Power Research Institute, Inc.

Dr. Bethany Frew, Senior Engineer, National Renewable Energy Laboratory

Arne Olson, Senior Partner, Energy and Environmental Economics, Inc.

Dr. Congcong Wang, Lead, Day Ahead and Reliability Commitment, Midcontinent Independent System Operator, Inc.

Dr. Jinye Zhao, Principal Analyst, Advanced Technology Solutions, ISO New England, Inc.

(Cont'd.)

Panel 4: Out-of-Market Operator Actions Used to Manage Net Load Variability and Uncertainty

Panelists:

Yasser Bahbaz, Manager, Reliability Coordination, Southwest Power Pool, Inc.

Liam Baker, Vice President Regulatory Affairs, Eastern Generation

Chris Bossard, Shift Manager, Real-Time Operations, California Independent System Operator Corp.

Laura Rauch, Director, Settlements, Midcontinent Independent System Operator, Inc.

Noha Sidhom, Chief Investment Officer, Viribus Fund, on behalf of the Energy Trading Institute

William Fields, Deputy People's Counsel, Maryland Office of People's Counsel

P R O C E E D I N G S

(9:00 a.m.)

Welcome and Opening Remarks

MS. NICHOLSON: Good morning everyone. Thank you very much for joining us. My name is Emma Nicholson, and I'm with the Federal Energy Regulatory Commission's Office of Energy Policy and Innovation. Welcome to this virtual conference to discuss regional transmission organization and independent system operator, or RTO and ISO, energy and ancillary service markets in the evolving electricity sector.

This is the fourth technical conference the Commission has hosted this year in a series of technical conferences called Modernizing Electricity Market Design in Docket Number AD21-10. Today's conference will be the second of two conferences this fall that will focus on energy and ancillary service markets.

And the first conference was held last month on September 13. Before we begin with opening remarks from our Chairman and Commissioners, I wanted to communicate some logistics for the conference. We'll have two panels this morning, followed by a lunch break and two panels this afternoon.

Panel 1 will start immediately after the opening remarks. The conference is being webcast, but it will not be recorded for future viewing. Once we get these initial remarks out of the way I want to introduce our Chairman, Chairman Richard Glick for his opening remarks. Thank you Mr. Chairman.

CHAIRMAN GLICK: Thank you very much Emma, and thanks to your team for assembling this very important technical conference. I think this is going to be a very interesting staff led technical conference today. And I also want to thank the panelists for taking your time. I know everyone's busy, but taking up your time today to participate. We really appreciate that.

As Emma mentioned today's the second of the two technical conferences we're having on energy and ancillary services market reform, and we're very interested to hear everyone's views on the subject.

During the first conference we've kind of looked at it from a macro level, and examined some of the energy and ancillary service market reforms that might be needed to address the changing resource mix. Today we get down into more of the detail kind of the nitty gritty, and the first two panels are going to focus on how resources offer their services into RTO and ISO markets.

The third panel is going to talk about how these markets actually select lease cost resources in the various markets around the country. And the fourth panel is going to focus on out of market action, out of market activities and how that impacts the energy ancillary services markets as well in terms of what we're looking at today.

So again I want to really thank everyone for participating today. I think it's going to be an interesting conference. I think I will be here for most of it. Unfortunately, a couple conflicting appointments, but for the most part I will be listening in and listening intently on the record, and really look forward to a good discussion today.

Before I turn it back to you Emma, I'm going to ask my colleagues if they have opening comments, and I'll start with Commissioner Danly.

COMMISSIONER DANLEY: Thank you Mr. Chairman. I appreciate it. I don't have a whole lot to say in preliminaries except that I appreciate everybody being here, and I look forward to the discussion. I too will be coming in and out as necessary to other appointments today.

One thing that I want to say is that in those markets that have capacity markets, even though I acknowledge that there are any number of potential valuable reforms to the energy ancillary services markets, those reforms cannot take the place of a properly functioning capacity market in those cases where there is one. So I just want to make that point before we begin, and I look forward to listening to the discussion and reviewing the transcript once everything is completed. Thank you Mr. Chairman.

CHAIRMAN GLICK: Thank you Commissioner Danly. Commissioner Clements?

COMMISSIONER CLEMENTS: Thanks Chairman Glick and good morning, it's nice to see you all. Thanks to staff for putting on the second technical conference. It's a lot of work under any circumstances certainly as we continue to do these virtually. We know you're putting in a lot of time and my advisors and I really agree that this agenda is really excellent. I look forward to learning from all of today's panelists.

As the Chairman said it's really getting into the weeds, which is a place I like to be. I'm thinking I'll learn a lot from all of you, and all of the panels. I won't be in-person for the fourth, but we'll get to see that later.

But in particular, three things come to mind for me. First is market rules -- and whether those rules properly committing inclusion of the costs that resources are incurring for being flexible.

Second is the extent to which self-commitment and self-scheduling rules are impacting the flexibility available to operators. I know some of your pre-conference comments covered this. And then third, whether eligibility and operators are following behind advances, and the capabilities of newer technology and resources such that they may be acting as -- those rules may be acting in barriers of participation.

So with that thanks for being here today and for investing the time.

CHAIRMAN GLICK: Thank you Commissioner Clements. Commissioner Christie?

COMMISSIONER CHRISTIE: Thank you Mr. Chairman. I would just like to thank staff for all the work that you did putting these on. These are very time intensive, and very energy intensive, no pun intended. And so I really want to thank staff for all the work you put into these.

And I also want to thank the panelists. You've put a lot of time in as well. And so I want to thank you for that. I'll be listening today. I don't think I'll have any questions, but I'll reserve the right to jump in with one, but I don't have any planned. So I'm going to be listening and learning, and again thank you to everybody for all the work you do to putting this conference on. Thank you Mr. Chairman.

CHAIRMAN GLICK: Thank you Commissioner Christie. And now I'll turn it back to Emma to get us started today. Thank you Emma.

Panel 1: Incenting Resources to Reflect Their Full Operational Flexibility in Energy and Ancillary Services Offers

MS. NICHOLSON: Thank you very much Chairman Glick, Commissioner Danly, Commissioner Clements and Commissioner Christie for joining us today, and providing opening statements. We will now proceed to our first panel for today.

I really appreciate everyone for joining and I thank our panelists. This is the first of four panelists, and Panel 1 will focus on incentives that RTO and ISO system resources have to offer their operational capabilities into the market, the energy and ancillary services market today. Again, my name is Emma Nicholson, I work in the Regulatory Commission, or FERC's Office of Energy Policy and Innovation. And I'm joined by my colleague and co-moderator for Panel 1, Michael McLaughlin who is a Director of Division of Economic and Technical Analysis in the Policy Office.

And this panel will run through -- and before we get started I want to have a traditional request that all Commissioners -- all panelists avoid discussion of actions that are active and pending before the Commission. We issued a notice that notice all the dockets that are currently pending.

We have my colleague, Adam Eldean from the Office of the General Counsel is available here to notify us if we're discussing ex parte matters, but we request that all of our panelists today avoid the types of discussions that would require us to redirect the conversation, but I'm very excited to have this conversation today in Panel 1 about resource incentives and the extent to which current RTO and ISO energy and ancillary service market rules encourage resources to offer flexibility into energy markets.

So right now I will pass the mic to my colleague Michael McLaughlin. Thank you.

MR. MCLAUGHLIN: Good morning and thank you Emma. Thank you to all the panelists for being here. As Emma mentioned I'm Mike McLaughlin, Policy Office, and have the opportunity to ask the first question of the day. The first question will be addressed to all panelists. I will call each panelist in turn. I will ask the initial responses are no longer than five minutes.

After all the panelists have responded there will be time for each panelist to respond to the initial comment. First question. Do any existing RTO/ISO energy ancillary services market rules, requirements or procedures, actually encourage resources to offer into the market inflexibly, and if so what changes should be made.

First up is Dr. Nicole Bouchez, the Principal

Economist, Market Design, in New York.

DR. BOUCHEZ: Thank you very much. First I'd like to thank the FERC Commissioners and staff for the opportunity to participate in this technical conference. In New York our focus has been on the wholesale energy products that are needed for reliability in the face of an evolving resource mix. And at the same time ensuring that the broadest set of resources possible can participate in those markets.

Generally in New York's structure of our market rules is to increase the financial returns for resources that reform flexibly and reliably in the real time markets, and reduce compensation for inflexible units. Co-optimizing in our energy and ancillary service markets both in the day ahead and the real time markets causes the prices for energy and ancillary services to reflect the costs of system providing the ancillary services.

And to compensate for providing ancillary services when the unit would otherwise be providing energy. This opportunity to sell different products also has the potential to encourage resources to make investments or modify operating practices to participate in those markets.

These investments can however be costly, which is why the focus on reliability and the products needed to maintain reliability is so important. We have a very solid market design that performs very well, and market design will continue to serve as well as we look towards the grid of the future.

We do not have any preference for specific technologies or resources. The market rules we have are based on the reliability needs, both the needs of our operators and the requirements of the reliability oversight organizations. In our case that would be in particular, NERC and the New York State Reliability Council.

We are continually looking at our rules to increase participation because as you recognize in this technical conference, more participation in ancillary services is a good thing. If we don't have sufficient parameters modeled to adequately model a technology's capabilities, we work on evolving the participation model so that they can participate.

In the next panel we will be talking about new and emerging resource types and what the NYISO is doing to accommodate their participation models, so I won't cover it here. But I wanted to talk about two examples that are a little different. In New York we've gone from hourly scheduling of imports and exports to quarter hour scheduling on several of our interfaces with our neighbors to provide additional flexibility.

We are even considering moving towards five minute scheduling to provide further flexibility. To give another example our current rules are not completely able to reflect the ability of combined cycle units to participate in ancillary service markets. We have a current project that is looking at ways to better reflect their operating capability.

Finally, you asked to the extent to which our rules account for existing fuel limitations like natural gas supplies that have the potential to impact resource flexibility. Resources bid and notify the NYISO of fuel limitations, and they're taken into account in the reference practices that are developed for mitigation, and obviously in the dispatch as well. I think that's it for now, thank you.

MR. MCLAUGHLIN: Thank you Nicole. Next up is Joseph Daniel, Manager, Electricity Markets, the Climate and Energy Program of Union of Concerned Scientists.

MR. DANIEL: Thank you. Thank you Mr. Chairman, Commissioners, and Commissioner staff for assembling this technical conference and for inviting me and the other panelists to speak. The first thing I want to get out of the way is to make very clear why I think flexibility is important, and those reasons are reliability and affordability. A more flexible grid will lower costs, and therefore be more affordable to the consumer, and more flexible grid will be more reliable.

And those are my priorities when I'm thinking about flexibility. And I sometimes find it difficult to disaggregate some of the flexibility issues with some of the behavior that I would categorize as uneconomic behavior in the markets. I also want to recognize that the bulk of my own statement focused on the questions three and four about self-scheduling, and I will save the bulk of my responses to those questions when we get to them.

But in the meantime I will just recognize that I do feel like self-scheduling itself commitment are a limiting factor in the current rate's flexibility, and that while some of the most inflexible resources like coal steam units, are often categorized as being inflexible, and operate inflexible.

Those operations do not necessarily represent their inherent engineering limitations. There may be exceptions to this categorization, you know, many coal plants are not being operated to their full potential. And when I look at the current rules that govern our energy and ancillary services markets, I've kind of come to the conclusion that most of today's rules were written for yesterday's resources, and I think there can be no doubt that we have to look at any one of the ISO or RTO queues to see that the resource mix is changing.

And you know encouraged by Order 841 and 2222. FERC is clearly working to find ways to accommodate that inevitable wave of new lower-cost, more flexible resources and those efforts are laudable, however you know I think some of today's existing rules, including those governing the commitment and scheduling of resources tend to bias towards inflexible long lead time resources and against newer more flexible technologies.

Although these rules appear to be neutral in application, in that they allow all resources to say self-commit, the impact effects resources very differently. That's one of the things that I wanted to talk about in greater detail later.

FERC should pursue market fixes to promote the better resources that enter the market, and to offer in a full range of flexibility. And just as important we need to recognize that the market or incentive-based solutions to this issue often rely on a fundamental assumption that power plant operators will respond to the price signals formed by market auctions that the ISOs are administering.

And this is an assumption is not universally applicable to all power plants, particularly those in the RTOs and ISOs where most of the resources are still operated by vertically integrated utilities, and these power plants are in rate base. And so as long as power plants operators are out there and you know might be insulated from those price signals, price signal based solutions are going to struggle to its full potential.

That's not to say that we shouldn't you know pursue those, it's just that we need to you know kind of go into those conversations with open eyes about the limitations. And also recognize that we're not limited to sort of price signal based solutions. Market monitors are authorized to conduct a range of oversight and regulatory functions in order to prevent say market manipulation, and help ensure just and reasonable rates.

And there are ways to sort of translate those types of actions into similar actions that govern our commitment practices in a way that will promote flexibility. And then I also you know look forward to talking about a range of options that I think FERC should look at when pursuing fixes including finding ways to help encourage utilities to operate their coal plants at lower PMINs.

And also you know more tangible action the Commission can take when it comes to information gathering, reporting, working with state Commissions directly, and you know my final recommendation, you know a couple week's earlier, is just to make sure that as we make these steps towards creating market rules that will promote flexibility, we recognize you know the limitations to that.

And try to find ways to make sure that the market rules objectives actually achieve what we're solving for, and I look forward to expanding on this today in some of the later questions, and just want to thank the Commission again for inviting me to speak.

MR. MCLAUGHLIN: Thank you. Next up is Sherman Knight, president, Competitive Power Ventures.

MR. KNIGHT: Thank you Michael. Thank you Commissioners for this opportunity to speak. My remarks today reflect my opinions in my own capacity, not those of my company. Having said that, our company's success is entirely dependent upon grid availability to develop, build, new renewable resources which I think is all dependent upon the ability to manage intermittent resources within the existing grid, which I think ultimately comes down to flexibility in doing so.

So we are very interested in this technical conference and very much appreciate the opportunity to speak. I think from my perspective I think that one of the key attributes here is really distinguishing between cost of value and price. This came up actually this weekend. I had a leak in my upstairs bathroom. It drifted to the ceiling of my dining room.

I shut off the water, brought a plumber over. He said yes, you know the material is about $20.00, his time is about $30.00, and he was going to charge me $100.00. I was like no problem. You know the cost was obviously only $50.00, the value to me was well over $100.00, and we arranged for a price.

And I think one of the fundamental things with flexibility right now is that we don't have to distinguish between the value of flexibility out there. So back to the question. I think there's two issues, ultimately it's ramp rate and ancillary services -- the volume of ancillary services.

As a generator we dispatch typically five to 10, to 15 minute intervals. We put in energy offers at various levels you know for the cost of generation, and then we also put in the ramp rate. The reality is there's no value distinguished if you put a ramp rate of five megawatts per minute, 20 megawatts per minute, 40 megawatts per minute, or one megawatt per minute. You get paid the same amount in the energy market.

And so from you know the ISO's are relying on the ability for a lot of the fast ramp units currently, whether it's peakers, or applied cycles, to flexibly manage that inter commitment resources as they're coming on. The value to the generator is zero. There's literally no difference in terms of what one gets paid for that.

And so I think you know kind of going to Nicole and Joe's comments I agree with them. I think that what that leads to is basically me going back to the plumber saying I'm going to pay you less than cost. You know, please do my fix. You know the value to me is high, I'm not going to pay you anything for it.

And so you might get to my house, you might not. You know I think from a general perspective it's like ah, there's not a lot of value putting in flexibility into the ISO, you know why do it. You know I will do what I need to, but I'm not going to really push and there's not an incentive to be super flexible.

And then part of that is then all that flexibility is going into the energy market where five minutes you're getting fluctuated up and down quite rapidly. The volume of ancillary services then needs to be procured and get shrunk, and because that gets shrunk the value of the actual ancillary services in terms of regulation and everything else, actually diminishes.

Whereas if that's measured in terms of the actual flexibility across the value of the actual flexibility needed across the system you know it's not truly reflected. So I would just encourage you know us to you know be candid about what actually is needed you know to bring on the renewable resources.

Let's make sure that there's incentives out there for coal plants you know to put a PMINs down, a ramp rate higher to what their capabilities are. To note self-schedule, you know, all those actions are done because there's not value in the market to do so.

And whether that's through the energy market, you know, some form of incentive to show your true ramp rate or to increase your ramp rate and make technical fixes, or put more you know volume into the ancillary services and make the energy market you know just more of a steady market, either one can work from my standpoint, but actually finding what that value is is important. Thank you again for the opportunity.

MR. MCLAUGHLIN: Thank you. Next up is Karen Onaran, Vice President, Electricity Consumers Resource Council. Karen?

MS. ONARAN: Great. Well thank you so much Chairman Glick, Commissioners and Commission staff for the invitation to speak today, and of course for providing a platform for the consumer perspective because at the end of the day whatever we do, the consumers will be paying for it.

And so in answer to the question you know whether this particular rules are either hindering or promoting certain resources and the flexibility. You know I would say there's not a one size fits all, and so that all of them can use some improvement to some extent. And I think what we really need to focus on is what is the problem that we are trying to solve. And that is a not a reserve problem.

I think if you look at the generation that we have available now, and even what's in the queue. We have more generation than we could possibly ever use. So what we really do want to be solving for is the flexibility to manage variability. And there are two sides to that coin. There is the supply variability, and there's also the demand variability, and they both should be at the table to focus on these issues and help solve them.

So I think you know one of the things that we're seeing is perhaps an over procurement of resources, some of which are just sitting there waiting to be called on. And as consumers we really want to be paying for generation that provides a service, provides the energy. I think we don't want to pay for generation just because it exists.

And so I think that we really need to be looking at the variability and the flexibility as something that we need to incent. And the way that we can possibly do that is you know what are the attributes that we really need and really want out of our generation, and place a value on that. So you know, if it's more flexibility, able to ramp up, ramp down you know quickly, you know put a value on that.

If it is for longer term backup resources put a value on that. And I think that with those incentives hopefully it will send the correct price signals. You know as Mr. Daniel brought up earlier that sometimes generation is not always responsive to price signals, but you know I would hope that with the proper incentives put in place that they will be inclined to you know to get into the market according to their capabilities.

So I think that it really takes some reflection and looking at all of the possible contingencies, and what the likelihood of those contingencies, you know, to make informed decisions. Do you know in the winter that there will be supply chain -- these potential supply chain issues.

Do you know that some of your generators are unable to perform once the temperature reaches a certain level? Are you winter peaking? Are you summer peaking? You know do forecast errors, you know sometimes that doesn't make a huge deal, in other regions that does. We'll probably hear from Mr. Sorenson and SPP later that they have tremendous variable resources with their incredible wind potential.

So a forecast error in SPP has a great impact than say a forecast error in a place that relies on primarily, on natural gas, or other base load fuels. So we really want to make sure that we're measuring those contingencies, and how often they may happen. Place that value so that we're pointed to cost signals, and that the operators who you know her, or his first priority is reliability, and so he's not always -- he or she is not always going to rely on cost to make those decisions.

So we want to make sure that they have the tools. And then we look at the demand side of this. Of course, that is also going to be variable in the upcoming future, the near future as we see more demand response, we see distributed energy resources. Demand is you know sometimes very questionable, especially as we get closer to electrification.

You know when are people going to be charging you know their cars, and so it's going to change the load profile, and so we need to make sure that we understand that profile as well, and are able to respond to those customer decisions.

Also I think separately we need to have customers at the table when we do talk about this, and that's to really gain an understanding of the tolerance level. Again, you know for the industrial customers that I represent. Having a potential outage, or you know, a limited outage. Maybe an hour, maybe even a day, some of our customers would have a tolerance for that. They can reroute operations to a different facility, and would rather do that than pay exorbitant costs for generation that's just sitting there waiting to be called on.

Others you know are willing to pay a price for reliability. They you know don't really care. They're known as price sensitive. They just need to have that reliability, that 24/7 good power quality, and so I think and understanding of what tolerance levels are, and I think in the prior technical conference that D.C.'s public office you know counsel, brought up a good point is we need to have demand at the table when we discuss this to understand the level of tolerance.

And I think a little bit of education even for the average retail customer. I know that's difficult. I've always been taught that the customer only thinks about their utility in two scenarios, and one is when their lights go out, and two is when their bill arrives, and either time they're not very happy. So let's have them understand exactly what they're paying for, and what their tolerance level is as well.

You know they hate it when they lights go out, but you know is the price that they're paying so extreme that we could you know lower those costs and have them understand and come to the table with solutions, and perhaps their tolerance level as well for interruptions in the power supply.

So with that I'll wrap up, but I look forward to the future questions, and thank you again for having me.

MR. MCLAUGHLIN: Thank you Karen. Next up is Tom Kaslow, Vice President Market Policy, FirstLight Power.

MR. KASLOW: Thank you Michael. And first a thank you to the Chairman, the Commissioners, yourself, Emma and David, and other staff who put this conference together. I really appreciate that opportunity to share FirstLight's thoughts with the panel.

I am the Vice President of Market Policy for FirstLight Power. We own and operate in New England a fleet of hydro resources. We have the largest pump storage facility in New England, and we also have another facility is the oldest pump storage facility in the United States. We also have a solar farm and two customers sited with the lithium ion battery.

So we provide considerable flexibility to the supply of energy and the region's ramping needs, peak supply, dispatchable load to manage generation, over-supply, top line and synchronized research in ATC, we do it all, so we're really interested in this topic.

At least in New England, uplift eligibility and other details in the day ahead and real time markets seem to work reasonably, well with of course the biggest exception in the New England market is we don't have the day ahead reserve market yet. We're hopeful that ISO New England completes that day ahead design and files it with the Commission soon to correct that thought.

However, supply offer rules governing the flexibility into the day ahead and real time markets, really starts at the point of capacity. Those rules require permission to dispatch flexibility that the capacity resources design can support. For existing resources with known designs, the current rules that apply upon their sale of capacity do obtain the flexibility that is possible from them.

While the current market rules require flexibility from equipment inside the generating tent, some resource designs like gas only fired resources do rely on equipment outside of that like gas supply and transportation infrastructure. And the market rules can and do require them to seat gas, but the market rules cannot require them to get gas, an uncontrolled event.

Further, as costs of spot gas increases, the least efficient units get pushed out the dispatch stack, and just for practical purposes really get out of reach of the ISO system operators and other resources run harkening to Karen's earlier comments.

So with respect to new investment we think the question needs to be asked is why would a new investor considering adding resource flexibility want to do so if their outcome is only to be paid the same capacity price as the resource that's extremely inflexible and rarely are never run.

The consequence of this flaw is likely to manifest itself by either narrowing new investments to technologies less capable of flexibility, under designing of technologies that could otherwise be flexible, or the most inefficient of all -- precluding ISO dispatch of otherwise flexible resources by their choice to operate outside the RTO/ISO markets as unregistered distributed generating resources, or behind the meter resources.

Those resources must be scheduled 100 percent of the time, and not only does ISO not control them, they cannot even see their operation for a time. FirstLight encourages the Commission to think of the operating reserve market as a three legged stool, for the day ahead market, the real time market, and the capacity market of the three legs.

There's no day ahead or real time fix that substitutes in correcting the capacity market flaw that exists, which I think is driving some of the concerns that Karen mentioned. The effectiveness of that compensation signal is central to encouraging flexibility. Equal pay demands equal work. A lot of hope was placed on pay for performance to do that, however in New England with only one event in three years that designs, at least as designed does not appear up to the task.

The common obligation to some form of enhancement, or adjunct the PFT should apply to situations where the system is tight, but prior to reaching a deficiency. We have ideas and there are other stakeholders within New England that are talking about these types of changes, and we hope that that will be considered in light of priorities that are given to ISO New England, and thank you for the opportunity to present these comments, and I look forward to questions, thank you.

MR. MCLAUGHLIN: Thank you Tom. Next up is Greg Sorenson, Manager, Market Surveillance and Mitigation, Southwest Power Pool, Greg?

MR. SORENSON: Thank you. Good morning Chairman. Good morning Commissioners. Thank you very much for inviting me to be part of this panel and represent the Southwest Power Pool market monitoring unit as we discuss the future of energy and ancillary service markets.

These markets are a very important part of ensuring reliability as they allow the system operator to specify the quantity of ancillary services required to safe operation, and then allow the market to obtain the optimal set of resources. Certain maintenance costs increase as units operate in a more flexible manner.

Additionally, we've observed that price volatility to reduce generator's confidence that market prices will remain high, which leaves them to sometimes operate near their day ahead position instead of being flexible in the real time market for unforeseen events.

And as renewable generation increases, we have seen the price volatility increase in both SPP integrated marketplace and the western electricity market. Volatile prices make starting even more financially risky. In particular, additionally we see as the variable energy resources increase, that 5 percent forecast error and manifest itself on a 15,000 megawatt wind day as a 750 megawatt shortage, which is the size of many power plants.

In the SPP market that market monitoring unit has spent time in the last few years discussing the importance of placing units in market commitment instead of self-commitment status. This practice of not allowing, or excuse me, the SPP practice of not allowing self-committed resources has encouraged resources to offer in a market status.

As more resources offer in market status, if they have load that faster start up times lead to more commitments. Initially, we have observed units increase their ramp rates after major overalls, likely to respond to negative prices that appear in real time.

The real time market of SPP sees significant price volatility as ramp shortages lead to high real time prices for very short duration. While some resources have increased their ramp in order to capture this value, some resources have chosen to maintain their day ahead position as a result.

The ramp side which has been approved by the Commission and will be implemented in April 2022, will help smooth out these price hikes. The fast start changes to provide uplift to fast start meters will help encourage them to start. SPP could change the day ahead commitment cost and set a minimum run time instead of treating all the units longer than 24 hours the same.

This would encourage shorter minimum run times. On the other hand the start up and shut down for a steam unit leads to the thermal day can be relatively expensive to repair in major overhauls. The MMU in response spearheaded an effort a few years ago to allow the major maintenance cost to be included in the mitigated start up and no load offers.

Surprisingly, several resources have not yet applied to the market monitor for this additional cost to be added to their offers. While a rule could be added to require resources to offer full flexibility, more flexibility does come at a price, and that needs to be considered as a new rule is thought about.

Transitioning natural gas limitations are reflected in offers in two ways. Sometimes units must offer on a regular take, that is they have to take the same output for all 24 hours in the gas day, which removes all flexibility that unit had. A few years ago when gas prices were very low in west Texas, a number of natural gas resources were running constantly, more economically at the maximum which reduced the flexibility that normally exists with those units, it's just rougher.

And finally the MMU has observed that some natural gas providers are not open outside of 8:00 to 5:00 Monday through Friday, so you didn't think that otherwise start in 10 minutes to follow some sort of emergent problem, a very long lead time actually is hours.

It required all natural gas providers to provide some level of service 24 hours a day to help improve flexibility greatly. I thank you for the opportunity to present, and look forward to additional discussion with the expert panelists.

MR. MCLAUGHLIN: Thank you Greg. Our last panelist is Dr. Catherine Tyler, Deputy Market Monitor, Monitoring Analytics. Catherine?

DR. TYLER: Hi good morning everyone. I'm Catherine Tyler. I work for the Independent Market Monitor for PJM, who was on the panel in the last conference that began to address some of these issues, and we appreciate the opportunity to come back and speak to them some more.

I will start by pointing out that the way the question was framed I think is not quite the right question, it's not where our concerns are. The question isn't necessarily whether resources offer flexibility, but we need them to perform flexibly, so there is a different there.

The PUC rules require offering flexible parameters. We have must offer requirements in energy and reserve markets. There's plenty of flexibility on paper. There's a general lack of accountability to perform flexibly in the market. PJM has a rule to establish physical offer parameters that must be included in parameter limited offers. These should be used in market power mitigation and during stress market conditions consistently.

But PJM implements the rules in a way that makes it very easy for resources to avoid commitment on those offers. And the market's flexibility needs increase using those parameter limited offers will become more crucial.

We observed situations where offers are flexible, but the actual performance is not flexible. The market needs to account for the performance of the resources. Customers see a premium for capacity that is meant to meet performance standards. Some examples -- PJM has called synchronized reserve events for load dates on high load days when units could not achieve their economic maximum due to ambient temperatures.

And there are no repercussions in the outage rules or the uplift rules. This is a failure to meet energy market must offer requirements, and the solution would be penalties based on capacity market prices. Investment in turbines in PJM has been called on based on cost based offers with special notification times, but the unit could not come on because they were not fast, and there were no repercussions for this.

PJM told these resources then to submit what they call real time values, which are overrides of the required notification times, but there's no repercussions for this situation. And PJM hasn't proposed a workable solution to the problem. The logical solution here again is penalties based on the capacity market prices which are paid for meeting certain performance standards.

PJM also is regularly reducing the amount of reserves that it calculates from what is offered because PJM does not trust the ramp rates or the performance of certain units. The ramp rates are offered, but they're not achieved. It would be better to clear reserves based on the offered ramp rates and then use stronger penalties for non-performance, so we can get the right offers to match the performance.

So overall the flexibility is offered, but it doesn't always translate into real time performance. This undermines reliability. PJM needs rules that discourage rather than reward this behavior. In most cases the reward for this behavior is uplift payments. Resources that do not follow PJM's dispatch instructions should not receive uplift.

Where we do see limited offered flexibility is, as has already been mentioned, generator modeling, especially for combined cycles, as this leads directly to less flexible offers than what generators can perform to. The stakeholder process has been an obstacle to improvement in this area, and this is because better generator modeling goes hand in hand as it should with more accountability for performance.

And so we need some perhaps help there to move those proposals forward when they stall in the stakeholder process even though they're very much needed. On the question of the gas scheduling, the PJM rules accommodate inflexibility due to gas scheduling restrictions. These restrictions are becoming more common, and it's not only in the winter, its' also on hot summer days. And the rules are accommodating the inflexibility.

We allow 24 hour minimum run time and long notification times based on something that's coming up from the gas pipeline. And this is accommodated through generous uplift payments that allow the cost of this pipeline inflexibility to be passed on to customers.

This shouldn't be an acceptable standard. Capacity resources should be required to have dual fuel or flexible firm gas supply arrangement, and currently the accommodation for the inflexibility on the gas side are all being pushed from the gas business to the electric business.

Reforms are needed not just on the electric side, but also to get more flexibility and accountability from the fuel suppliers as well. So overall I think the comments that we have, and I think that's typical out of what we've heard already are that you know we need to set some standards on the capacity side to make sure that we know which flexible resources are there that we need, and then to hold those resources to higher performance standards. Thank you.

MR. MCLAUGHLIN: Thanks Catherine. And thanks to all the panelists for their initial responses. And at this point I encourage each panelist to respond to the great points made so far, and Emma, the Chairman and Commissioners, also to ask follow-up questions. If you have comments please raise your hand and I will call on you in order. Thank you.

MS. NICHOLSON: Karen Onaran you have your hand up. Please go ahead, and then we will have followed by Sherman Knight and Tom Kaslow please.

MS. ONARAN: Yeah thank you Emma, and I just wanted to follow up a little bit on what Dr. Tyler had to say. You know as far as penalties, and I do agree you know we're always you know about cost causation and beneficiary pays, and so I want to make sure that when we do have specific penalties perhaps for those that commit, but do not show up, or do not perform as flexibly as they expected, that there is a mechanism to make sure that those penalties are not then transferred to customer costs.

So just wanted to make that point. I absolutely do agree that penalties are necessary when there is not the performance expectations, but just want to protect those customers and make sure that that's just not -- those penalties aren't then transferred to the customer.

MS. NICHOLSON: Thanks Karen. Sherman Knight from CPV.

MR. KNIGHT: Sure. Thank you. I think I want to address Dr. Tyler's -- some of her comments. I think penalties do make sense to a certain extent for obligations that want to put on tolling. I think if we set a standard on capacity market for a certain flexibility, I think we're you know as an overall ISO we're going to be clipping the total capability of all.

For example, standard sets a minimum hurdle in which you have to apply, but I think there's a lot that can be done in some of the existing generation that could create additional flexibility. And a lot of it is just kind of right around the engines. So for a specific example a lot of our combined cycles have you can ramp from the minimum, you know, operating condition. You can ramp the gas turbine up, the steam turbine comes up and on the ramp rate.

And then you put in duct firing, which is gas directly to the boilers, which just does the steam turbine. And that ramp rate is a different ramp rate because it's really a different mechanism. But there's really no way to put in the two different ramp rates. So to the extent that there's penalties for not putting in a ramp rate, you know, for example for not meeting a ramp rate.

You know the natural inclination is you go with the lower one so that you're not getting penalized. But that would then preclude a significant amount of you know ramping that occurs in you know the lower portion of the commodity cycle. So I'm not trying to you know like say that specific one, but I just think that there's a lot of very technical specific things, and that's just a combined cycle.

And I don't know about hydro, or you know other resources that I think if one only sets a minimum standard we're going to end up with a lot of generators that are only meeting that minimum standards, and that's where I think it's more important to set it up such that there's an incentive to get the maximum out of each of the generation assets, and then everybody out there, each of the I should say resources -- storage, you know, demand response, then everybody goes to the drawing board and can think about what is the most effective economic way to create that flexibility in the system.

Which may not be obvious to any of us on the panel. You know it's probably obvious to a lot of like engineers behind the scenes, but not necessarily from our perspective.

MS. NICHOLSON: Thank you Sherman. Tom Kaslow, FirstLight?

MR. KASLOW: Thank you Emma. It's encouraging to hear the focus on this panel on the importance of making sure that the products that are purchased, that the resources that are required to deliver them. I would emphasize though that carrots are certainly more effective in markets than sticks, but we don't have revenues to reinvest in the facilities that provide flexibility it's going to be a very inefficient loss in flexibility.

So if penalties when they use them in this term are code for financial settlement of performance obligations not delivered, then we would agree. The problems -- at least in New England, I think it probably exists in the other markets too, is that the capacity market obligation is not the same for all.

Our facilities, particularly our pump storage facility operates every day, and it provides a lot of savings to the system many times each year from having reserve deficiencies, yet we're paid the same price as any other one of the resources in our fleet. It rarely, if ever runs. And so we're missing something there we had great hopes for PFP and I am still a big supporter of that. I think that we're just relying solely on deficiencies to enforce the flexibility that we need to avoid deficiencies of where the shortfall is and initial design, hopefully there's some focus on that going forward, thank you.

MS. NICHOLSON: Thank you Tom. Can we hear from Greg Sorenson from SPP?

MR. SORENSON: Yeah thank you Emma. I would like to note that you know I think Karen Onaran was definitely on to something by highlighting the importance of the increased demand participation, and there's a lot of opportunities in both demand response, and distributed energy and other types of collaborative efforts to increase the amount that demands respond to prices, and increase the amount that the demand responds to other types of emergencies.

And I think that's essential for flexibility as you continue to add more and more intermittent resources you have to figure out who is willing to get out of the system at some price, and then keep the rest of it reliable.

And I think also as we think about the value, what is the value of the generation, and then what does the generator need to get paid in order to perform. And certainly during the winter weather events you know it was definitely highlighted that the generator needs to be compensated not just for their actual cost to shore up our margin also out of the generation, but also they expect to recover some amount to cover their risk of actually you know being able to start in an emergency.

So they have to be able to cover both of those to feel like the value that they're getting paid is sufficient for them to actually be able to perform both during emergencies, and just provide general flexibility, thank you.

MS. NICHOLSON: Thank you Greg. Can we hear from Catherine Tyler, Monitoring Analytics?

DR. TYLER: Yeah thanks. I appreciate the other panelists comments on the question of penalties. The penalties versus higher payments, both of which are incentives, is an important question, and we do acknowledge recognizing Sherman Knight's comments about ramp rates that generator modeling issues contribute a lot to some of these inflexibility issues that come up, especially for combined cycles, and better modeling to match the capabilities of the resources would help a lot.

The thing that we see over and over the last several years in PJM is discussions of flexibility leading to new market design changes that will see capacity performance, faster pricing. PJM's proposed extended operating reserve demand curve, all you know in the name of providing more revenue streams for resources that are flexible, but in all cases they also create higher revenue streams for the resources that are inflexible at the same time.

So we can keep doing this, but it's not going to lead where we really need to be, which is in a place where the resources that are in the fleet are those that are flexible and are ready to perform flexibly. We need to look at these proposed changes and not only how they affect the resources with the flexibility, but those with the inflexibility.

MS. NICHOLSON: Thank you very much. I have some follow-up questions, but I wanted to confirm if the Chairman, Chairman Glick and Commissioners have any questions. Do you have any follow-up questions please go ahead and jump in, or raise your hand.

All right. Hearing none, thank you all very much for your answers there and responses. I think it's certainly very important that we both need a resource to have incentive to both offer and perform and I think we all sort of assumed that an offer flows through naturally to performance, but thank you for clarifying Catherine that we do need both resources to make their flexibility available to the market, and respond flexibly, and we've heard I think about two schools of thought about the carrot and stick approach.

And to Tom, that's exactly how I think of it, Tom Kaslow, and in terms of well how do you get the best performance out of people. And I'd love to hear your thoughts as to which is the more effective approach and also we've also heard some discussion at the last conference, and this one about which market, the energy or the capacity market that is most appropriate to procure and compensate resources for flexibility.

We've heard a lot of comments in the final panel on market design at the last conference that energy and ancillary services markets are most ripe and appropriate to incent more flexibility because they're real time, they're very dynamic and capacity markets are often three years forward, and have a single capacity requirement for the entire year, whereas flexibility requirements not only do they vary within the day or the hour.

They change markedly depending on weather events, so I'd love to hear some of this discussed if the panelists could talk about for those who think capacity markets are the appropriate mechanism to require flexibility, how would a capacity market incent in resource flexibility if it's so forward, so long in advance, and also any comments that you have on sort of a carrot versus stick approach of incenting through payment versus punishing through penalty resource flexibility.

So raise your hands, I'd love some comments. How about first we have Dr. Nichole Bouchez, I think it's Bouchez, that's the French pronunciation and then I see Tom Kaslow, so please Nicole.

MS. BOUCHEZ: Either pronunciation works Emma. So we don't think the capacity markets are the primary way to incent flexibility. And are really sort of entertaining ancillary markets and more and even most importantly the real time market is really where the rubber meets the road. That's where the need is, and that's where the response matters. And so we've really focused on those areas, in terms of what is needed from the resources, and also what capability can the resources bring to the table.

And you know we want the broadest participation possible, but we also want effective participation is what it comes down to. You asked about carrot versus stick. I mean I think both come into play. If you don't have the carrot it doesn't make any sense right? You need to correctly compensate for the cost, and make sure that you're covering the cost incurred of the units who are responding.

On the other hand there are consequences to not responding, and those are needed as well. So you know I think both carrot and stick are in play there, thanks.

MS. NICHOLSON: Great. Thank you very much Nicole. Can we hear from Tom Kaslow of FirstLight please?

MR. KASLOW: Thank you Emma. I think it's useful to have these panels because we all arrive with different perspectives, and following the last comment I recognize that it is the real time operation where the rubber hits the road of the RTO/ISO system operator -- that's their focus keeping the lights on.

However, the rubber hits the road well before that from a commercial standpoint. If the consequence of making a capacity sale is that our resource has to offer its full design flexibility into the day ahead and real time markets, the title is transferred there. That's where the commercial transaction is really made. The rest of the discussion about what happens in the day ahead and real time is really just a question of whether or not there is any payment, and at what level.

The sale has been made. It may be that certain resources end up being more flexible and more economic to provide that flexibility on a given day in the day ahead and real time, but the obligation on all of us starts in advance. So if that is ignored, we would be ignoring the fact that that forward obligation is actually bounding the future day ahead and real time outcomes.

They have the obligation to do it to an extent. So I think they all work together as I use the three legged stool. It really can't be separated, or else the stool will not stand.

MS. NICHOLSON: Thank you Tom. Dr. Catherine Tyler?

DR. TYLER: Yeah thank you. I absolutely agree that the energy and capacity markets need to work together. Of course there is a real challenge there when you have cost of service markets, or parts of your market, and then that question really doesn't apply and creating incentives for investments becomes much trickier.

At PJM luckily, we have a capacity market that could be used better in this regard if the capacity market payments, or even also your uplift payments in real time are your carrots that you're offering out there, that comes with these obligations as Tom Kaslow was just saying, to perform flexibly, and to provide the services that the market needs -- the capacity market puts that out there for the needed investment to be made for the needed maintenance to be done.

And you know at PJM we've been working towards a new approach to the ELCC that's a tool that can be used both for renewables and for thermal resources to really look at who is available, and who performs, and who performs the way that is needed, and then you have a situation where you can make sure that you are offering that incentive to the right set of resources.

But then you need to have something in place to take that away when they don't provide what they are being paid to provide.

MS. NICHOLSON: Great, thank you. We also have Greg Sorenson from the SPP.

MR. SORENSON: Yes thank you Emma. Just a short comment, and I think it's important to recognize that the need for flexibility is not the same during every single hour of the day and is not the same as you go from load to load. So for example at SPP you know the regulation up and regulation down requirements are calibrated for each hour, and that's based on the value of the load, how much we think the load is going to change, and also how much intermittent resources we have, and how much we think they're going to change in each hour.

And so that's very important because certain hours I might only need to change if the operators come up with 600 megawatts of reserves, other times I might need to come up with 1,000 megawatts of reserves for reliable service. That provides an appropriate balance between making sure we're flexible, making sure we're reliable, and not procuring more reserve services than we actually need.

And similarly, we care how that uncertainty price will be allocated. Now if this is required it will vary each hour based on the anticipated system needs for it.

MS. NICHOLSON: Thank you very much Greg. I have one other follow-up from the movers and shakers that are generators on the panel. We have heard from Sherman Knight and Tom Kaslow that right now you're not in the markets -- are not giving you the incentives, and that essentially you would get the same -- to be flexible, excuse me, that you might get the same compensation for, or just receive your cost for being flexible versus not.

And we'd love to hear from you what do you need, and what markets, if any, do you think are doing particularly well in this area. Greg just mentioned a ramping product that I know is not in force in the northeast yet, but it exists in MISO and California, and will come out in SPP. Would something like a ramp product, or other reforms work?

I would love to hear what you need, what resources need from these markets to have the incentives to both offer and perform flexibly to meet the changing system needs, so if Sherman or Tom have a response we'd love to hear from you. And I see Tom your hand is raised. Please go ahead.

MR. KASLOW: Thanks. We're not discouraging if there's interest in some type of a ramping product. We're not in the markets that currently have one of those. Anecdotally I'm hearing that they're not particularly effective, at least in terms of supporting the investment flexibility.

And as a practical matter I think it would be useful to look at the contribution of capacity market revenues over time to resources' revenue adequacy. The capacity payments are a substantial portion of what the resources rely on to continue their reinvestment in facilities, so if you need to look at offer rates, as we learned in school, but there is no substitute for getting the capacity market right, and to point back to Karen Onaran's comments earlier that consumers don't really want to pay for capacity for resources that they're not getting much from.

We completely agree with that. There is a problem in the New England market right now where those surpluses we have, you know, you get 1,350 megawatt surplus beyond the installed capacity requirement, and now you're down between $3.00 per kilowatt month.

And if that was all based on the common product sale, that would be a fair outcome. The problem is the $2.60 price that we just had ends up being comprised of resources that know they're not going to be asked to do too much, and we know that firsthand because we had one that went through our fleet. I didn't mention we have this one little 20 megawatt kerosene fired jet. It can do stuff, it hypothetically can.

And under ELCC it will probably do fairly well, but it just doesn't operate much because it's outside of dispatch economics. And so as a consequence we really need something that's going to provide a common obligation. You know everyone can't provide the same level of performance.

And when I say a common obligation, not that everyone has to supply that there's a 5 megawatts per minute ramp, but that there is an evaluation of the extent of contributions that they make that ends up factoring into their capacity compensation.

So you know our little jet that can but doesn't, probably doesn't deserve as much of a payment.

And the resource that runs a lot like our pump storage facility probably deserves more than the current market price reflects because we're obligated to provide more than others are. Yeah, we've got an energy payment, and some operating reserve payments, but frankly those are tiny compared to the capacity payments, other than gross energy revenues. I'm talking about net energy margin.

So one of the thoughts that we're having and actually shared within New England is coming up with a common obligation. We've had several different ideas. We're actually trying to converge stakeholder proposals because having many proposals before the ISOs just seems a lot of resources efficient rates to have common need definition and a common solution.

But it's coming. The current concept is probably more likened to some form of an energy call option where everyone's subject to the same type of financial settlement that we all talked about, and the strike price on that would be very high, just at criteria.

It would be much lower when we had significant surplus and separate at least from the material, that significant surplus. So hopefully there will be more coming on that. I don't have more design to give you.

MS. NICHOLSON: Great, thank you very much Tom. And Sherman, you've also kindly agreed to answer, so go fire away thanks.

MR. KNIGHT: Sure. Thank you for that. I think from our standpoint I think the capacity given that it's three years in advance in some markets, or at least a month long product, it's not granular enough to fully provide just you know the needed flexibility when it's needed.

And I think Greg Sorenson summed it up extremely well that there's certain hours during the day, and certain months during the you know, when more is needed, and sometimes less is needed, and therefore the value of that you know increases and decreases depending upon when the demand for supply is at.

I think you know to put it into more granular context, you know, back to kind of the engineering of it. You know for example at some of our plants when we ramp past a certain level we have to turn on a boiler feed pump. That -- every time you cycle that, you know, it's known after you know 4,000 cycles you have to spend $400,000.00.

So you know we don't want to move it past that ramp forming you know because we're not getting you know paid to do so, then you know we're just incurring costs. And that's a very granular thing. You know for example will we do that to meet a reliability need? Absolutely. Will we do that -- are we happy about doing that when we get uplift payments and get paid our theoretical costs back? Not particularly excited about that.

So you know there's not currently a mechanism to have that granularity. And the other thing you know for example is we can create more flexibility by lowering the min load of some of our combustion turbines or combined cycle plans, primarily because the min load is set by basically ignitions that locks levels.

And combustion technology is approved. We change out the combustion, it's investment, we can drop that you know increase the amount that we can ramp by you know call it 5, 10 megawatts, I'm not exactly sure for example. That requires the investment, and currently there's no mechanism to actually get paid for that investment.

And going back to Karen's comment about from a consumer perspective, I think from an incentive point of view I think we can do that much cheaper, than building out a 5 to 10 megawatt battery. And so if the attributes are put in the market, and I think it has to be more than energy and ancillary service or real time because it is very you know granular, that creates then the economic incentive to go about meeting those attributes in the lowest cost way.

Maybe that's a lithium ion battery. Maybe it's simply you know, changing out combustors at some of the plants to be able to lower that min load. Maybe it's you know just cycling the boiler feed pump more. I don't know the actual answer, but right now there isn't that granular ability on a real time basis to actually figure out the best economic tradeoffs which ultimately will lead to the lowest price for consumers.

MS. NICHOLSON: Thank you very much Sherman and Tom for answering. I'm going to now pass the mic to my co-moderator Michael McLaughlin.

MR. MCLAUGHLIN: Thank you all for these great responses and thoughts. The next question for the panel is to what extent do the existing self-scheduling rules in RTO/ISO markets reduce the amount of operational flexibility available to the RTO/ISO market, are options for self-scheduling needed to allow resource owners to make the best use of their assets over time?

What market design changes that might encourage more resources to compete economically. Please raise your hand and we will call on you in order. Yes Nicole's hand went up first and then Tom.

DR. BOUCHEZ: Sorry you cut out for a second. I didn't hear my name. Thank you. I think in this discussion we have to distinguish between self-scheduling and self-commitment, at least in New York because the two are very different. And they have very different impacts on flexibility.

Self-scheduling absolutely does reduce the amount of operational flexibility available in the real time. It's less clear that self-commitment does, and I'll talk about that a little bit later. In New York self-scheduling appears largely to be used to accommodate inflexible contracts. For example, natural gas contracts or legacy physical contracts even.

And then in more limited cases to reflect operational limitations, either of the resource itself, or of the natural gas pipeline. And our focus should be to get entities to negotiate more flexible contracts, and to have the natural gas pipelines provide gas as flexibly as possible, including potentially investing in flexibility.

And the markets encourage that right? We have more in the long run because in the long run it's not clear that self-scheduling is profit maximizing for suppliers, because ultimately self-scheduling leaves money on the table occasionally. It doesn't always, but it does you know. And so the incentives at least are in the right direction there.

But self-commitment is a little different because it's less clear that it reduces operational flexibility available in real time. Self-commitment, and in New York we think of self-commitment as either a self-commitment bid mode which we have, or potentially by changing operational parameters to make your -- the unit get committed, so we see that as well.

It's all about commitment horizon. New York commitment horizon in the day ahead market is 24 hours, and is approximately two hours in real time, and I won't go into all the vagaries of that. But the resources that expect to operate longer than that right, in a longer time horizon, they have the commitment risk to determine when they should be committed, and when they shouldn't.

And that's where we see these self-commitment modes and bidding behavior being used. So I think there are good reasons to continue to allow self-commitment, but there are also really good reasons to discourage the use of self-scheduling, and to build rules so that the financial incentives are not to self-schedule in our markets, thanks.

MR. MCLAUGHLIN: I think Tom was next.

MR. KASLOW: Thank you Michael. Many of the discussions, including the start to this one, focused on the ISO registered resources, the ones that are observable and under their dispatchment. However, one of the things that's happening in the industry now is an increase in the amount of resources that impact the wholesale market, but do so from outside the ISO's sight and control and talking about resources that are connected with the distribution system or behind the meter that aren't registered, and all of their operation is a self-schedule of an even tougher type.

Since the RTO can't oversee their occurrence, or even directly observe it when it occurs, you need to try to forecast those changes. And on top of the fact that they reduce the amount of connected load that needs to be met by the flexible resources that are under dispatch control.

And while those resources by definition are outside of FERC jurisdiction, the FERC jurisdictional markets actually encourage this less flexible form of business model through preferential incentives that were provided under the RTO/ISO market. For example, in New England, based on the recent forward capacity auction a 1 megawatt retail load could operate a 1 megawatt battery for the single coincident peak load hour in the prior year and obtain 140 percent of the capacity value of the same 1 megawatt battery if operated as an ISO registered resource in the capacity market.

So that's based on the cost allocation design that we have. Others may have similar designs, and it also means that a customer could avoid paying any capacity charges that rely on the capacity purchases paid by other customers and all other 8,759 hours. So that type of a functional signal to not be in the market subject to the ISO dispatch, maybe one that gets the biggest bang for the buck here.

With respect to resources that are under the RTO/ISO control I think the incentive to not self-schedule are a good five minute prices. If you self-schedule you're going to get a lower price, but there are good reasons why some amount of self-commitment in particular, I think that clarification is a good one, need to happen.

You know, we operate energy storage facilities, and much of the time the coordination between the storage injections, and the storage happens within the constraints of the facility according to the day ahead and real time market offering, but that's not always. And sometimes they need to actually use some of the real time generation to make space to accommodate the day ahead purchases.

Other resources face similar situations, a gas unit might buy a gas package and face not a very liquid gas market, and the better option is actually to liquidate that gas by burning it, and selling the energy and the more liquid ISO electric market. Similar things happened when resources fed by LNG need to make room for incoming tankers.

Hydro stations need to do it in order to make room and offer reservoir in the station for calls, approaching storm front is forecast, resource testing is another reason. So it can't be, and shouldn't be eliminated. But I think it's important to have the right signals.

And in New England certainly the absence of the day ahead operating reserve market isn't helping that, and that's something that needs to happen there in any event. Thank you for the opportunity.

MR. MCLAUGHLIN: Thank you Tom. Joseph I think you're next.

MR. DANIEL: Thanks. And I want to start off by saying that I agree with Nicole that self-commitment and schedule have to be distinguished. They're two unique practices, but I end up landing somewhere different when it comes to the impact of self-commitment on flexibility, at least in markets like SPP and MISO where I looked at this issue most closely.

And I want to start off by discussing how resource self-commitment differs in practice. And let me use an example of a coal unit and a wind unit, those are equal in this example or illustration would apply to. So if you have a coal unit that is self-committed and is operating at PMIN, if the grid operator can turn that unit up if market prices go up and clear it's cost offer.

But essentially the grid operator, the market operator can't dispatch that unit any further down, and it can't turn off that unit because of the commitment status. I don't know if there's an emergency. Now this stands to me in stark contrast to the way self-commitment works for a wind resource where you know wind self-commitments have essentially no impact on price or flexibility because the ISO -- the protocols for wind resources require that wind to be dispatchable down to payment, and for when zero is at zero.

So that means that the operator could effectively turn off that unit, and you have the full flexibility of the wind turbines along with that wind turbine is available. And so you have dispatch down you know basically to zero for most wind turbines in the U.S.

And so the impact of self-commitment shows up. It's a regional like SPP or MISO in the form of wind curtailment. Now you know at the onset I understand a lot of wind curtailment is caused by transmission constraints, but there is emerging evidence by power plants, and many of them also own wind farms that their inability to you know be dispatched down below their PMIN or operate below the PMIN forces them to curtain wind resources.

And it's my assessment that once transmission constraints are resolved, it is the inflexible operation of self-committed resources that operate at you know unreasonably high PMINs that will be the you know dominate all of that for maintaining cost-effective reliability while integrating higher levels of wind and solar and renewable energy and electric vehicles and sort of getting to the grid that we know is coming.

But the thing is that there are many of these wind curtailment beds in SPP and MISO are 24 hours long, or 72 hours long, and if a single cold event, you know, not necessarily in the whole plant, but a 350 megawatt unit were to be turned offline, there are plenty of other resources available during those seasons when these events are happening which is typically spring and fall where there's a surplus of capacity.

So the grid operator could maintain not only meeting peak demand in its reserve markets, and have lower system costs, and avoid these curtailments. It's actually you know, from an engineering perspective, and economic perspective all a perfectly achievable outcome.

And I think one of the things that was really surprising to me is over the past couple of years I've started to talk to solar developers and renewable energy developers who told me that one of the things that they look for when they're trying to locate where their power plants, or where their facilities are going to be sited, number one is transmission, and number two is you know the power plant operations of coal fired power plants and other inflexible resources, to see if that resource is going to suppress prices and create all sorts of problems in terms of flooding the grid with an inflexible power source, such that they're the ones that are going to have to be dispatched out.

And they're the ones that are going to have to be curtailed because you know ultimately the inverter based technologies, wind, solar, storage, they're a lot more flexible than those coal plants, the grid operator will turn those units down. And so once those coal resources hit their PMIN, you know there is now a flexibility issue at play. And you know I'll say you know I'll wrap up saying if those PMINs are not set in stone right, they can be changed.

Some of them require actual capital additions to make those changes, but some of them you know have never, you know, I worked in a lot of state PUC's and you know I'll get involved in these rate cases, and ask you know the utility have you ever done an engineering study on what their PMINs needs to be set at and none of that has.

You know there's been a couple utilities that have started to actually do tests to test the PMAN and they found out that oh yeah, we were at a 60 percent PMAN and then we were at a 50 percent PMIN, and now we're at a 40 and we're testing 30. So we're actually currently doing that process.

But you know most of them it's just been totally operated at a certain level, or they'll use the contracts which I think earlier -- say, we have a fuel contract such that we set our PMIN based off an attempt to avoid liquidated damages in our coal contracts.

But at which point you know there's all sorts of other accounting issues that happen when they start to ramp. So there are like real -- there absolutely are physical flexibility limitations that are on the grid when you have these high PMIN resources self-committing into the markets.

MR. MCLAUGHLIN: Thank you. I believe Greg was next.

MR. SORENSON: Yes, thank you Michael. Thank you Mr. Daniel for those comments. I do agree with you it is a problem when people have inflexibility with contacts, and the only reason why they're not producing you know a minimum is they feel they have to earn that. And that's something unfortunate for everybody -- the consumer and our bills alike.

I think as far as I would agree that your transmission causes are the main issue when the price diverges, at least the wind curtailment at least in SPP. Another issue we do observe is that wind generators will tend to under offer in the day ahead market, which means that more units end up getting committed than was otherwise needed.

We sometimes see that the wind that's offered can be as low as 80 percent of what actually shows up which of course 80 percent of 15,000 is you know you're leaving at you need 3,000 megawatts of thermal resources that have to be committed in order to meet the reliability needs.

But transitioning a little bit you know we do observe that self-commitment does actually increase the amount of upwards operational flexibility during hot weather and cold weather events that could be more important to the grid. However, as you did note you know MMU analysis also notes that prices are suppressed and generators that particularly get subsidized by state regulatory processes usually fair much better by self-committing. And we've observed that merchant generators from a thermal and renewable are disproportionately hurt by this practice, and if you separate out the self-commits you'll find disproportionately people who have the state utility commissions as it backs out, so less uncertainty and concern, probably least to recall for otherwise needed.

Self-scheduling was in part eluded to that does greatly decrease the operational flexibility for the market, and just as an example you know, if you have a hydro unit with a ramp up rate of 20 megawatts per minute, at least at the economic commitment of 102 and then back 104.

You know that means there's only two megawatts of ramp actually available to the market value, so they're not actually being very flexible in making use of either specific self-scheduling or having very low amount of flexibility, and that would be based on the aggregate.

I think you know as some other people have already noted there are some reasons to do self-commitment and self-scheduling, environmental testing, longer lead time resources that cannot otherwise be committed by the day ahead market as well as from the greater sensitivity of cold weather.

It's important that those resources are ahead of time, otherwise they really might be good options, in particular with SPP you know, the Southwest Power Pool provides uplift for resources at market status which allows them to recover from the market, operators to operate the generators, in contrast self-scheduling, you know you assume all participants have --

Additionally we've added the addition of major maintenance costs and offers, recovery of costs, starting to operate particularly when the system operator has to start the unit for some sort of emergency.

Finally, the market monitoring unit recommended the self-commitment study in its annual report with an additional day of optimization. And we think that would greatly reduce the available resources that could not be committed by the day ahead market, because that's another -- when we've done the surveys, that's why people say they like self-commit because they didn't think they could use market commit.

Additional data and studies should help resolve that situation. Thank you very much.

MR. MCLAUGHLIN: Thanks Greg. Catherine I believe you're next.

DR. TYLER: Yeah thank you. A lot of great comments here. We have not had a problems with self-commitment, and I definitely agree with that important distinction between the commitment of the resource and then how actually what level to schedule at or dispatch at.

The disqualification of uplift payments does limit the behavior, although we do acknowledge the less economic behavior of regulated cost of service resources. There are some issues there, and I will clarify just going back to the earlier question that comes up here as well.

We use the word penalties rather than carrots, but what we really mean is simply taking away the carrot that was given in the first place. Whether that's uplift revenue, capacity revenue, or reserve revenue when the resources don't perform rather than you know additional charges.

And that comes into play with this question of self-commitment and self-scheduling for sure, and uplift is very important in this discussion where we observe issues are when resources are receiving uplift, remaining eligible for uplift while either their offer or through their behavior they are self-scheduling. They're ignoring the economic dispatch instruction.

Explicitly this can be done in PJM by something that's called the fixed gen flag, like you just turn it on, and it says hey PJM I am not following your dispatch instruction at all, so I'm just going to do whatever I'm going to do to the extent you've committed me, whereas other resources can effectively do the same thing by just ignoring their dispatch instructions.

And these resources do remain eligible for uplift when they should not. They should be treated as if they're self-committed. Sometimes this happens for some resources because they require a phone call to change their output levels, but the market creates no incentive to install automation, or AGC. The flexibility there is offered as if the resource could be dispatched up and down, but it's not provided because there's no communication of the dispatch signal to the unit.

There's also lack of automation for scheduling CTs or diesels and other real time resources. And that's unnecessary and inefficient. And the PJM dispatchers are using a phone call to call on a resource in real time and to call them off when you know both on the PJM side, and on the resource side there should be software that sends specific call on and call of times that could then be used for accountability in the uplift settlement rules.

And this ties back to that self-commitment issue because what you're looking for is economic and flexible and precise timing of when you need the resource on, when you need the resource up, and certainly there's plenty of automation and software available to make that happen and to create that accountability for when it doesn't happen. Thank you.

MR. MCLAUGHLIN: Okay. Thank you. I want to check and see if anyone else has follow-ups, or if the Chairman or Commissioners have any questions here that they would like to ask.

COMMISSIONER CLEMENTS: I'd like -- this is Commissioner Clements. I'd like to jump in with a question.

MR. MCLAUGHLIN: Great, thank you.

COMMISSIONER CLEMENTS: Thanks. This goes back a little bit to the previous question, but certainly is related to the onset of answers that you all just provided. So if flexibility is not valued, and therefore not compensated properly, I would think intuitively that good scarcity pricing on its own would incent some level of flexibility, so you capture the profits when the prices go high and operating right, when the prices go low.

But it sounds like this isn't fully working. I'm just wondering whether when you talk about whether we need capacity changes or a ramping product, or you know, some combination, how do we think about the part of the solution set on valuation that is the efficacy of scarcity pricing approaches.

MR. MCLAUGHLIN: I'm not sure, Karen?

MS. ONARAN: Yeah thank you Michael, and I'll follow-up with Commissioner Clements' question as well, but I just wanted to you know point out that consumers in general are not a big fan of self-commitment. I think what we agree is we would love to pay for the flexibility. What we don't want to pay for is inflexible units that commit themselves when they're otherwise uneconomical.

So if you know they have a certain plant that they want to keep online, but it's not necessarily you know clearing certain markets, and they want to continue to operate and get payments for, we certainly don't want to prop up uneconomical products.

And I think so in looking at the market mechanisms to try to dis-incent that, and I think you know what Dr. Bouchez said, sorry about that, is you now we have to work to incent for those not to self-commit, and I think what Dr. Tyler had said was you know, instead of maybe penalizing, we're taking away that carrot.

And so you know I really think that from the consumer perspective you know we want to pay to make sure that we have secure power. We're not going to prop up uneconomical generation resources.

MR. MCLAUGHLIN: Thank you Karen. Joseph did you have your hand up earlier?

MR. DANIEL: I did, but it was in response to something one of the other panelists said, so why don't we continue with some of the responses to what the Commissioner's question is.

MR. MCLAUGHLIN: Tom Kaslow, I believe you were next.

MR. KASLOW: Thank you Michael, and thank you Commissioner Clements for the question. I think there's one thing that's useful to keep in mind by trying to understand why current mechanisms don't work as well. A market signal relies on running out of operating reserve, that's the definition of scarcity that we inform.

Those events can and do occur. The event that we had I think was due to a substantial change in import flows that actually turned to exports when hydro Quebec experienced some problems on their own system. So that was -- I would consider that's a pretty extreme event, probably one that the ISO operators didn't plan on for that particular day.

But if there's an absence of flexibility initially on the system, just to say some of the resources that are there are removed, ultimately in the day ahead scheduling the ISO is still responsible for developing a reliable operating plan for the next day. They can't plan into a scarcity. Indeed they take actions to avoid that.

So we've put ourselves in the situation of relying on a market signal that only comes into place when we run out of what we need. Probably not a good idea to rely solely on that, hence power companies and others within New England's focus on market signals that would set a premium on flexibility when systems may be a little bit tight, but not in deficiency.

And something that's more tied to the capacity market, not to rule out the possibility of something like ORDC, so I appreciate Karen's earlier comments about the side effects of that, but something that requires everyone to provide more contribution toward avoiding scarcity events as opposed to awaiting the outcome of a scarcity event.

I was a big supporter of PFP, I thought that was a great idea at the time, and just finding out through experience. Maybe we had a great design, just off by a slight hair. Thank you.

MR. MCLAUGHLIN: Mr. Sherman I believe you were next.

MR. KNIGHT: Sure. Thank you Commissioner Clements. I think it's a good question on scarcity pricing. I think that the answer that I would give is it's 50 percent, it would help part of it. So scarcity pricing occurs you know regarding the real time operations.

So for those generators that are off line or at EcoMin, yes it provides a very strong incentive to move up quickly, flexibly, as fast as you can, but for those generators that are online and running at top load, or were committed in the day ahead market, it doesn't do anything. It doesn't incentivize the flexibility that's inherently there.

So you know bringing you back to an example, back to a combined cycle. It provides a huge amount of flexibility to the grid. They move up and down all the time. But when the market is tight they're dispatched in the day ahead market typically all the way to the top.

They still have a tremendous amount of flexibility inherent because they can ramp down dramatically. So for example, you know if wind or solar, really it's wind you know has a lot more output than expected, you can ramp those units down. That has a value. Scarcity pricing doesn't actually help that because they're already dispatched at the top. It doesn't provide any more incentives for them to be flexible. So I think partly, but I don't think entirely.

MR. MCLAUGHLIN: Thank you. Greg I think you were next.

MR. SORENSON: Yes thank you. I agree with Sherman's comments, and I would add that a lot of times at

SPP we only have a five minute scarcity price signal, so that tends to be actually too volatile for some generators to respond. The other thing that we observed is that system operators will actually commit units ahead and in real time, which have the effect of removing those price scarcity signals, and so you know that they committed the unit to get more flexibility on the system, that price signal does not make it into the market.

So that's the other reason why it's important I think to look at these ramp products and uncertainty products, products which solve specific issues just like the issues of the system, thank you.

MR. MCLAUGHLIN: Thank you. I think you broke up a little bit there for me. Did you finish your comments Greg?

MR. SORENSON: Yeah go ahead thanks.

MR. MCLAUGHLIN: Thank you. Catherine I think you were next.

DR. TYLER: Yeah thank you. Yes shortage pricing is very important, and we do see -- and I think it was expressed in the last conference by PJM that a reserve shortage is really considered to be an unacceptable outcome. And it's something to be avoided at all costs from the operation's perspective, and perhaps we see shortages occur, especially short-term ones that don't turn out to be a crisis, and the operators are not taking emergency steps to avoid it.

So there's something of a mindset that is limiting the amount of shortage pricing that we're seeing at PJM. And of course, we're facing a market design change that's imminent in May 2022, where PJM wants to extend the operating reserve demand curve out so that potentially what you get is scarcity pricing all the time, which is much more costly than -- and a much less targeted price signal than the shortage pricing that we see today, so that's an important distinction to make, and there is something that needs to be done there in the ORDC reforms, and also with that mindset around you know what a shortage means, especially if it's not a crisis and not going to last that long. Thanks.

MR. MCLAUGHLIN: Okay. Thank you Catherine. Nicole, excuse me.

DR. BOUCHEZ: Thank you very much, and thank you Commissioner Clements for the focus on the incentives for flexibility. What the NYISO rules do is focus really specifically on those intended flexibility, and the question is entirely correct that scarcity pricing is part of that solution.

And again, you know it's really that focus on the real time markets, and on the needs that is really driving that. And yes I love this discussion of carrots and you know, and taking away the carrots. We don't see that the right answer is to focus on capacity market compensation for flexibility because it's just not at the right time when we need it, and it's hard at that point to match sort of performance with what it is that was purchased.

We have under and over generation penalties in the settlement and dispatch model, you know, in real time. And those intervals align perfectly. So if they are not performing we have a penalty for it. And in addition to go back to some of the discussion we do not provide make whole payments for units for self-dispatching either.

So we are taking away sort of the carrots, to go back to that. And we think that that is really the way to go because you're tying performance to when you actually need it. Thank you.

MR. MCLAUGHLIN: Thanks Nicole. I want to circle back around to Joseph. I might have missed your hand earlier, so I apologize for that.

MR. DANIEL: No it's okay, and I realize we're short on time, so I'll keep my response as brief as possible. But it ties into sort of the theme that we've been talking about with the carrots and sticks. And one of the things that keeps me up at night is that if you know as has been mentioned by a couple of the other panelists, and it also says the same thing.

If you have a group of power plant operators of the vertically integrated utilities not responding to the current suite of carrots and sticks, then I'm not entirely convinced that changing the carrots and sticks are going to necessarily precipitate the changes that you want. Take the multi-day commitment practice that SPP is considering.

Well most of the coal plants I'm aware of that self-commit in SPP -- and I'm certainly not aware of all of them, but what they use for their commitment practice is a 7 to 10 day outlook of prices. And so if you know if they get you know a 2 day outlook through the market versus their own internal 7 to 10 day outlook, well they're still going to self-commit at the same levels that they have been because their window for commitment is 7 to 10 days and not two or even three.

So that's where I you know if that doesn't work, we'll commit to mission two. Well actually information and education can be a huge factor in helping precipitate change. You know and I'll take some ownership to some of the confusion of self-scheduling and self-commitment within my world because first off I wrote about this issue was five or six years ago, and I used the two terms interchangeably and was very quickly corrected, and I appreciate that.

But it was about six years ago and SPP's self-commitment practices, and almost immediately afterwards state regulators would come up to me and say oh, well they never heard about this issue before. This wasn't on their radar. But when I talked to people at SPP, or the SPP market monitor, or people at FERC, they were all very much aware of this issue, and it was just never getting out into the public. It was never getting into the Commissioner's hands.

It's really engaging with the public which hopefully the offers of participating will help to, and engaging with state regulators through venues like you know what the Commission is doing with transmission, with the joint task force, but doing similar types of engagements directly with Commissions to say you know you can't necessarily report all of this data publicly because there is a lot of confidential information.

But a way of saying all right well you know we can't help but notice that you know the distribution of PMIN for coal units is really clustered around 30 to 50 percent, but there's a whole bunch owned by one utility that's at 70 percent. Why are they outliers?

Are their boilers some how of a unique vintage that they have to operate differently, or is there some other underlying factor that we can get at, and by publishing this data in a way that respects confidentiality obviously, you know, there's a certain level of shaming them and praising others for those who operate the most flexibility, or who are operating the least flexibility.

And I think pursuing or exploring those options through technical conferences, through direct engagement with the states is a really powerful tool that I hope the Commission avails itself of.

MS. NICHOLSON: Thank you very much Joe. I think we have got to our final question from the agenda there that we have to get to. I'd like to check in with our Chairman and Commissioners and see if you have any final questions for the panel?

Okay. I think you're on mute, or I can't hear you Mr. Chairman. I actually can't. If you type your question in the chat we can ask her, sorry we can't hear you. Sorry, we'll address your audio issue later Mr. Chairman. But I want to -- I think we'll go ahead and close this panel. I really appreciate on behalf of my colleagues and the Commission here, we really appreciate the panelists joining, and of course the Chairman and Commissioners.

We've heard a lot of really important information about flexibility and I think we're learning just how difficult it is to operate ISO/RTO markets. We have different regulatory structures, different costs, fuel supply arrangements, a lot of resource capabilities that they have to be accommodated in these offer rules, so we really appreciate your expertise to make sure we understand the full breadth of complexity of the problems and proposed solutions.

We're going to go ahead and close this panel out. The next panel will start at 11:15 and it's called Maximizing the Operational Flexibility Available from New and Emerging Resource Types, so again to the group thank you very much for joining all of our panelists and Chairman and Commissioners, and we hope to see you back at 11:15. And Capitol Connection we can go ahead and put on the hold slide.

(Break 10:50 a.m. - 11:15 a.m.)

Panel 2: Maximizing the Operational Flexibility Available from New and Emerging Resource Types

MR. SISKIND: Hello everyone and welcome back. Thanks to our first panel for an interesting and informative discussion. Time to start the second panel today, which focuses on maximizing the operational flexibility available from new and emerging resource types. My name is Aaron Siskind, and I work in FERC's Office of Energy Policy and Innovation.

I'm joined by my colleague Robert Fares with the Office of Energy Market Regulation. Panel 2 will run through approximately 12:30, and will focus on whether current RTO/ISO energy and ancillary service market rules present barriers to relatively new and emerging resources types, and if so, how market rules could be changed to allow these resources to offer in their full capabilities to the market, since permitting all resources including new resource types to offer in a manner that maximizes the operational flexibility available to RTO/ISO operators to better manage changing system needs.

I would also like to remind all participants to refrain from discussing the specific details of the pending contested proceedings listed on the supplemental notices issued on October 1 and October 7, 2021, and to refrain from any discussion of other pending contested proceedings.

If anyone engages in these kinds of discussions my colleague Adam Eldean from Office of General Counsel will interrupt the discussion to ask the speaker to avoid that topic. Thank you to our panelists for joining us.

To our panelists, Chairman, and Commissioners, please use the hand raise button if you'd like to ask a question or respond to another panelist. The first question is addressed to all panelists. I will call on each panelist in turn to give their response. I will ask the panelists limit their initial response to no longer than five minutes.

After all panelists have spoken we will give panelists a chance to respond to whatever has been said.

Our first question -- do existing RTO/ISO energy and ancillary service market rules, practices, or procedures prevent or otherwise obstruct relatively new and emerging resource types such as variable resources, hybrid resources and energy storage from fully participating in RTO/ISO markets and offering the operational flexibility they are capable of providing from a technical standpoint.

Our first panelist is Betsy Beck from Enel North America. Please go ahead Betsy.

MS. BECK: Thank you Aaron and good morning FERC Commissioners and staff. Thank you very much for the opportunity to participate in today's technical conference on energy and ancillary services. As I mentioned I'm Betsy Beck, and I'm the Director of Regulatory Affairs for the Central and Western U.S. for Enel North America.

Enel is a leading developer, owner and operator of renewable energy plants in the United States with over 6 and 1/2 gigawatts of wind, solar, geothermal and battery storage currently in operation, and several gigawatts currently under construction.

We also are one of the largest providers of demand response in the country, and also have emerging distributed energy resources, so we bring many different perspectives to this discussion.

In general we believe that existing energy and ancillary service market rules on paper do not limit participation of new emerging resource types like solar and battery storage. That said, existing energy and ancillary service markets have historically been designed around system needs and operating characteristics stemming from conventional resources.

With our rapidly evolving energy grid there is a need to re-evaluate certain market processes and procedures to ensure that they are enabling robust participation of new and flexible resources and sending efficient price signals.

We do believe, and our experience has shown that by and large energy and ancillary service markets do not explicitly limit the participation of specific resource types. Order 841 and other efforts in the past several years have led to a close examination of tariff language, and have mostly eliminated discriminatory language barring the participation of certain resource types.

One exception to this limitation is on the dispatchable, variable, energy resources, and their ability to participate in the regulation market in SPP. We're sure there are still a handful of other markets that bar participation, but by and large these issues have been addressed in recent years.

When it comes to the question of what is limiting flexibility and the participation of new and emerging resources in today's markets, I will echo and expand upon some of what was said by Mr. Daniel and Mr. Knight in the prior panel. Today's markets were built and designed around conventional resources who have traditionally not been highly flexible power plants.

This historical bias towards the characteristics of conventional resources has direct and indirect consequences. As has been previously discussed, practices like self-commitment and self-scheduling of resources limit the ability of operators to dispatch down, or turn off those resources, while as Mr. Daniel noted, renewable resources like wind and solar can always be dispatched down to zero.

Further, participation of these non-price responsive responses in the market mute and distort the price signals sent to the rest of the market. Also, parameters like PMIN and minimum run times are other elements of energy market dispatch protocols that need to be examined to evaluate their bias towards conventional resources, and the impact that it's having on efficient pricing and flexibility.

While these parameters were once necessary to run the market and solve for blocky resources, but continuing to solve around these characteristics we ultimately compensate resources for their costs of inflexibility. Ultimately this is muting price signals for resources like battery energy storage, and hybrid resources that can provide near infinite flexibility.

Additional elements of energy and ancillary service algorithms similarly limit the full flexibility of new resources to respond quickly, and as quickly and precisely as they are technically capable. One great example of this that was also previously mentioned is ramp rate limitation.

In SPP where the bulk of Enel's wind fleet operates, for dispatchable variable energy resources or DVER's more than 200 megawatts, ramp rates are limited to 8 megawatts per minute. And for units that are larger than 200 megawatts they're limited to 4 percent of their capacity per minute.

So as Mr. Knight pointed out earlier these fast responding resources are capable of moving quickly in response to dispatch signals, but are limited in their ability to do so, and are paid the same energy price as all other resources.

And I think it's also important to point out that this ramp limitation in SPP persists, even after all non-dispatchable variable energy resources in SPP have been required to invest hundreds of thousands of dollars to retrofit plans to comply with new requirements to be fully dispatchable, a change which we did support.

Lastly, as it relates to the flexibility delivered by ancillary services, I want to echo some of the sentiments we have heard today that we need to increase the quantity of ancillary services procured. We must recognize that the single largest contingency may not always be a large nuclear or coal unit tripping, so potentially a change in the jet stream affecting wind production, or an unexpected storm impacting solar production.

For Enel ancillary service market fundamentals, the quantity procured, and the price paid for them are some of the key factors we evaluate when it comes to investing in battery energy storage. And I think it's important to note that ERCOT is currently sending very strong investment signals through its ancillary service markets for investment in battery energy storage.

So in summary we don't believe that market rules per se are limiting flexible resource participation, but existing and legacy market design elements are having direct and indirect impacts on market dispatch, pricing and compensation that are muting investment signals for new flexible resources. Thank you and I look forward to our discussion.

MR. SISKIND: Thank you Betsey for those comments. Our next panelist is Jason Burwen from the Energy Storage Association. Please go ahead Jason.

MR. BURWEN: Great, thank you so much. Thank you to the staff and certainly to Chairman Glick and Commissioner Clements who is I believe attending this technical conference, for putting this together. This is a very important topic, certainly for the energy storage industry. I'm happy to speak to these topics from the perspective of the energy storage industry.

Thankfully, Betsy did a great job framing out the problem here, so I don't have to repeat to you the importance of how we need to avoid unduly discriminatory treatment by reducing our reliance on these accommodations for inflexibility that are built into market rules and policies, particularly because we have other commercial technologies, like for example current day battery storage that demonstrates such accommodations are recently not necessary.

And in addition to, as Betsy noted, revealing the presently embedded costs that inflexibility pose to system operations and allowing us to have the more robust price formation that reflects the value of flexibility. It's also about increasing operational efficiency and reducing reliance on out of market actions to be able to provide flexibility.

So from an energy resource perspective, we don't have a lot of experience with significant levels of storage in energy markets, not only just in megawatts to avoid, but also the track record in energy in multiple ancillary services, along with storage providing frequency regulation.

So we are still learning as we go as these new technologies begin operating at scale in energy and multiple ancillary services markets. And suffice that markets have been showing they can lean on assets like storage which has no start times or re-implementations or PMIN.

And I expect we'll learn plenty over the next couple of years beyond just the topics in discussion today. But one of the first things we're learning is that flexible storage is running into market processes that are not providing commensurate operator control because again they weren't designed with that thought in mind.

Systems operators love a resource that's always online and bidirectional that ramps instantly, quickly, but this is flexibility might not be used appropriately due to the simplifications or combinations in the market rules and operating practices. So the California ISO we're sort of seeing a first window into this storage is being reflected in the software as infinitely flexible. That's good. That's what Order 841 was intended to accomplish.

But storage assets are getting jerked around significantly as you move from hour ahead to 15 minute ahead, 5 minute ahead optimization, and then dispatch due to that flexibility. And that's incredible. The ISO has an asset that can turn on a dime and move around significantly as you approach a given interval, but asset managers, they're locked into bid parameters two hours in advance of the interval.

So all that flipping around doesn't actually includes significant updates to a state of charge or operational status of the storage. Price preferences and storage plant operator, even as the lost opportunity cost is swinging out, swinging around a whole bunch during those different optimizations, so that disconnect between slower bidding rules and fast and frequent change in dispatch or potential dispatch instructions can impose significant costs on storage units with uneconomical awards.

We're seeing a lot of out of merit dispatch of energy storage in Cal ISO, maybe 10 to 20 percent of the intervals might be including that, and that seems to suggest some trouble with forming price signals to produce the desired behavior within market. Certainly one potential solution that I think we can take from this, is that asset managers discretions to match a flexible capability of the asset, so a helpful solution might be allowing storage asset managers the ability to more readily respond to real time pricing and dispatch volatility, such as allowing them to modify bid parameters much more close up to the SCED interval.

I note this is apparently the planned new practice for storage in ERCOT. And this can certainly allow for better price formation that reflects asset options and preferences which helps us deal with the second issue of out of market actions. We are seeing out of market actions affecting storage flexibility. ISO has a requirement for storage used for RA to meet a known minimum state of charge.

We're seeing pricing anomalies leading from time to time to exceptional dispatch decisions that effectively now are keeping storage from dispatching though in interactions with that requirement. Those periods where storage is being forced to hold its state of charge despite pricing rules that indicate otherwise are first a lost opportunity cost that is not being compensated, but also at the same time those units are removed from the market temporarily affecting price formation.

This is in contrast to the thermal generators that are regularly kept burning fuel and spinning because their start up lead times might otherwise make them unavailable at future intervals if they be needed. Those generators are paid to remain at PMIN value, those actions are therefore compensated even though when they're not necessarily benefitting the market during that pricing period.

More generally, those thermal generators are otherwise free to participate in markets, so I think we need to be reducing reliance on out of market actions to produce flexibility. That reduces the price signal for flexibility that might otherwise be available for other assets, and it's really inappropriate for out of market actions from one resource type to be accommodating the constraints and then paying them for it, whereas for another resource types those assets are penalized for their constraints, and are not paid for it.

We need to be doing all we can to reveal price signals for flexibility and not securing them. So on this count we should be minimizing the distortions of out of market units on price formation. Then perhaps more radically in keeping with an idea for a performance based future where resources make single part offers because they no longer need to have start up plans, ramp rate limitations.

We could see a world where we're eliminating those kinds of make whole payments based on inflexibility and letting the generators actually go procure flexibility that they need, rather than have the system operator granting it administratively.

Certainly I think there's a lot more to say also about the nature of how ancillary services markets could be evolved into a wider set of flexibility reserves that you can cover at least at some part in the earlier parts of this, in the previous technical conference.

I think a key thing that we would raise here is that when you have current day ancillary services valued on the lost opportunity cost for providing energy, but in a higher renewables world, you can have energy prices presumably low or zero for significant stretches, that poses problems for valuing flexibility, especially if that named referent is energy pricing.

So how we value flexibility if it's an ancillary service, or a flexibility reserves construct, they need to be revisited and kind of like derived. I know that we've obviously had a discussion of ORDC's in these technical conferences before as one way that might look, but pay for performance principles -- two of the previous notes I've made about who bears and prevents the costs and benefits of inflexibility and out of market actions, pay for performance principles also point a way to ensure flexibility reserves or ancillary services show up as needed.

And that can evolve from use only for system emergencies to something continuously assessed in markets where flexibility is needed, and they can be designed to not be a cost to load, but rather a transfer between less flexible and more flexible assets based on the performance meeting the needs of the grid.

The grid of the future will need more flexible fast starting resources, so we need to make sure that we reflect the cost of a lack of performance to meeting that. Anyway, I know I've gone a little long. I'll conclude just by saying that my remarks today for the need for better asset manager control of flexible resources, and avoiding out of market actions that distort price formation, and moving to a new conception of ancillary services as pay for performance based flexibility reserves, these all point to potential paths forward given the needs of the higher renewable energy system, and the availability of flexible storage technologies.

I am sure we can take a wide view of the many different paths forward. And I'm just eager that the Commission continue to ensure policy keeps up with technology, rather than let the technology limitations of the past constrain our future. Thank you.

MR. SISKIND: Thank you Jason. Our next speaker is Mike DeSocio from New York ISO. Go ahead Michael.

MR. DESOCIO: Thank you Aaron. Good morning. We very much appreciate the Commission for its focus on these important issues, and thank you for the opportunity to be part of today's conference.

The topics are front and center in New York, and

I'm looking forward to today's conversation. New York's market design is structured to promote flexible resource operation. From the beginning the NYISO set out to develop the features and advancements to enable new technologies like limited energy storage resources back in 2009.

It enabled those types of resources to provide frequency regulation when they came to us and offered discussion of their capabilities. And again in 2009 we enabled wind non-dispatch where we allowed resources to provide costs of dispatch and let the ISO consider those costs when dispatching was to become vital in trying to balance today's grid.

The structure is built to reward those that can move quickly and follow dispatch instructions closely, and be responsive to emerging grid needs. New York's energy and ancillary service markets are open to all resources that can meet minimum eligibility requirements. There is no prohibition that prevents a resource existing new emerging from participating.

However, sometimes the characteristics of new resources require new functionality or dispatch constraints to be modeled, and often this is referred to as a barrier. In fact, wholesale markets were created to maximize consumer surplus and ISO/RTOs were given great responsibility to operate the grid as efficiently and as reliably as possible.

To do that, ISO/RTOs have information that is critical to grid operations, and confidential market information about each asset participating in the wholesale market. It is true ISO/RTOs also make as much data transparent as possible to improve market competition.

But ISO/RTOs also have confidential data of costs, output levels, current response rates, and future commitment of resources. This information asymmetry places ISOs and RTOs in the best position to make decisions that maximize consumer surplus for all customers. This can best be achieved when an ISO/RTO has line of sight to schedule and settle each resource, rather than aggregating these resources and leaving optimization to the set of resources through a market participant.

That said, aggregations are still important when thinking about managing separate small resources, and the ISO has created rules for such a structure through its DER participation model. In response to feedback from the stakeholders, NYISO continues to focus on improving its market models, and minimizing any perceived barriers to participate fully in its wholesale market.

For example, NYISO led the way with implementation of a full energy storage model which was released back in August of 2020. The NYISO is working diligently on its FERC improved DER participation model, and addressing the requirements presented by Order 2222. The NYISO is on track to implement its FERC approved collocated hybrid storage model by year end.

The NYISO also continues to work with its stakeholders considering opportunities for aggregation model for hybrid resources. And finally, the NYISO is working to develop a model for new internal HVDC lines that are planned to deliver clean energy into New York City.

These are just some of the improvements to New York's market structure that is important to make sure all resources can participate wholly. However, to facilitate and be prepared for the clean energy transition in the grid of the future, we need to think more broadly than participation models.

As the fleet transitions to one that is largely based on renewable resources, and energy or duration limited resources. The ISO also needs to be thinking about how their market structure is looking at capability, settlement structures work together to ensure that the resources continue to respond to grid needs and operator instructions.

The NYISO's grid and transition efforts are critically focused on evolving its market structure, and looks forward to working with the Commission and its stakeholders to continue to build upon New York's well-designed wholesale market structure. In addition, we need to be thinking about opportunities where we can strive to increase the ability for resources to submit additional data to the ISO more frequently.

I think Jason said it very well. There is a need to provide additional information more frequently, and the ISO is working on that. In fact for its energy storage model the ISO encourages that energy storage resources reach out to the ISO and look for ways to make offers more frequently in real time.

And this promotes improved efficiency and better price formation. But we are transitioning. And we don't have a grid where we dispatch based on renewables energy storage, so in the meantime we still need to manage these constraints such as PMINs and response rates to make sure we keep the lights on as we transition.

All of these pieces and parts are important, and the ISO continues to look forward to working with the stakeholders and the Commission on improving its market design. Thank you.

MR. SISKIND: Thank you Michael. Our next panelist is Brian George from EPSA. Go ahead Brian.

MR. GEORGE: So good morning. Thanks Aaron. Good morning to you and thank you to Chairman Glick and the Commissioners and staff for inviting me to participate on this important panel, and continuing the broader dialogue around modernizing electricity market design.

As always my views today do not reflect those of a particular EPSA member. As the trade association representing America's competitive power suppliers, EPSA believes that well-designed competitive electricity markets should provide price signals based on well-defined operational needs such that all qualified and capable resources can compete to maintain the reliability at the lowest cost.

EPSA members own and operate nearly 150,000 megawatts of generation capacity from all types of fuel sources. Today our members are actively developing new wind, solar and battery storage projects all around the country. Our members experience in developing and operating these resources can provide unique insight into how the Commission can utilize competitive markets to maximize the operational flexibility available from new and emerging resources.

Efforts by the Commission to reduce barriers to the participation of new and emerging resources such as Order 2222 and 841 have helped ensure these resources can compete in wholesale electricity markets. In particular, the biddable parameters for energy storage resources included in Order 841 was a good first step. However, operational experience may highlight areas for additional exploration and potential revision.

Importantly, the Commission should strive to design markets based on well-defined operational needs where all resources capable of providing the service have the opportunity to do so. While the Commission must remain vigilant for market rules that erect barriers for resource participation. It should avoid designing markets around the capabilities and limitations of particular resources.

The question for intermittent and use limited resources is less about their physical capability to provide certain services, and more about providing the right incentives. In many cases the potential to provide essential reliability services, traditional ancillary services and flexibility already exists.

As such, unlocking the full potential of intermittent and use limited resources will require well-designed markets that align individual, commercial interest with system operational needs. And I think Jason put it well when he was describing it, and I think we would agree.

And you know for example and in general, system operators who optimize large amounts of resources across geographically diverse balancing areas have more information about system-wide operational and reliability needs than do individual asset operators.

Conversely, individual asset operators who optimize their resource from a commercial perspective, may not have full insight into the broader needs of the system at any given point. Due to this information asymmetry, system operators may take action to posture use limited resources based on an operator's expectation of when that asset will be most valuable to meet system needs.

For use limited resources like storage, this can result in a mismatch whereby assets are required to maintain a day ahead schedule for a period that does not align with its greater arbitrage opportunity in real time, particularly during tight conditions.

While this example highlights some optimization challenges around use limited resources which will be addressed largely in the next panel, it also highlights the importance of allowing price signals to accurately reflect system operational needs. We should focus on getting as much information into the price signal so that asset owners can make the best commercial decisions that also reflect the best reliability outcomes.

Going forward successful integration of higher levels of intermittent resources require maximizing operational flexibility. Operational needs such as flexibility are exacerbated by increasing levels of intermittent and use limited resources. This effect will become more prominent as percentages of intermittent and use limited resources increase.

To effectively integrate more, we must maximize the operational flexibility of use limited and traditional resources to offset the variability and uncertainty on the system. More broadly, as the economy decarbonizes, the power sector will be responsible for delivering more electrons without compromising reliability, while the power sector itself is simultaneously transitioning to a lower carbon generation mix.

This highlights the critical need to have well-designed markets that align commercial interests and operational needs so that we can maximize the full value that all resources bring to the table. Thank you again for the opportunity to participate on today's panel and I look forward to the conversation.

MR. SISKIND: Thank you Brian. Our next speaker is Dr. Walter Graf, PJM, please go ahead Walter.

DR. GRAF: Thank you Aaron. Thank you Mr. Chairman, Commissioners and to FERC staff for organizing the panel today. I think it's a well-organized panel to dig a little deeper into a range of important topics related to flexibility, and I do appreciate the opportunity to represent PJM here today.

My name is Walter Graf, I'm the Senior Director of Economics at PJM Interconnection. So I'm going to kick off today with a bit of a devil's advocate position. Perhaps there will be something here that strikes a nerve, or gets a response from other panelists and spurs a discussion with my fellow panelists.

I'm very much looking forward to learning from the other panelists here today. So at the risk of being labeled anti-flexibility, my thesis is that the objective should not be to maximize operational flexibility, but to incentivize the efficient level of operational flexibility across all resources given the relative cost of providing that flexibility, and given the needs of the system for that flexibility.

So PJM happens to be behind some other areas in the country with respect to penetration of emerging and intermittent technologies, so we have the benefit of having a little more time to address any market design deficiencies before they become problems in terms of what does and doesn't work, in other ISOs and RTOs across the country as they face higher penetration of renewables before we do.

So I won't spend much time on here as it best fits under the topics covered under Panel 1, but I would point listeners to take a look at pre-conference comments that I filed to discuss the trade-offs between incentives and requirements for flexibility. The high level takeaway is that incentives for flexibility are a natural result of well-functioning energy and ancillary service market that reflect the balance of supply and demand throughout the day.

And operating flexibly, and investing in the capability to operate flexibility has real costs, and echoing some of the comments Mr. DeSocio made early in the panel, PJM continues to believe in the ability of the competitive markets to signal value through prices, and the ability of the competitive market participants to best make those trade-offs.

So it is our role as market designers to ensure that the market best reflects value and incentives, and that the incentives facing resources are aligned with what we'd like them to do. Dr. Tyler, the deputy market monitor for PJM in the last panel pointed out a number of ways that she and the IMM believes that there are deficiencies that could be corrected in the market to better reflect the value of flexibility, to better incentivize flexibility, and to penalize failures to perform.

I may agree with some, disagree with others, but here I do think there's a point that fundamental disagreement from the perspective that we must maximize flexibility. Trying to use the capacity market, or any other means necessary to enforce an obligation for maximum flexibility will ultimately leave efficiency on the table, and it will leave flexibility on the table.

As Mr. Knight pointed out in the last panel enforcing minimum standards means that we're going to get a little bit of performance, performance at the standard rather than unlocking all the flexibility that's available from each resource at the right price.

And so agreeing with Doctor Bouchez from the last panel, incentivizing flexibility and ensuring that we have sufficient flexibility when we need it is the role of the energy and ancillary service markets. We certainly see at least a few ways that we could improve these market rules and procedures to enable new and emerging resources finally getting right at answering the initial question.

In general, PJM believes that operational needs should guide the design of needed services, and should not be compromised to accommodate resources that are unable to comply. That said, there are cases where value can be unlocked or enabled without compromising these operational requirements. So one example that PJM is considering today is the potential to redefine certain ancillary service products as separate up and down products, which PJM does not have today.

This could have at least two distinct benefits. First, it allows the demand for those products to be differentiated if that's warranted by system conditions, so it might not be necessary to procure as much up ramp as down ramp, or vice versa under certain conditions.

And second, it allows different resources to supply different parts of what is today a single product, if and when that's a more efficient use of resource capabilities. So for example intermittent resources operating at their full available capability can offer fast responding down ramp capability without curtailing first to a lower level of operation, and then at the same time thermal resources dispatched to their economic minimum could offer fast responding up ramp capability.

Together these resources can provide the total needed ancillary services at a lower cost than would be possible under a single product definition. So this, and maybe there are other examples as well, we think that there are ways which the current market design does limit flexibility and can be improved.

But overall, we think that the definition of the various ancillary service products should be informed by both system requirements and resource capabilities. And as new and emerging resources become more widespread, it will become important to continue to evolve product definitions. We think that by respecting both we can efficiently enable the flexibility inherent in this technology without compromising the operational rules. Thank you for the opportunity and I look forward to the discussion.

MR. SISKIND: Thank you Walter. We appreciate that. And our last panelist is Dr. Nikita Singhal from EPRI. Please go ahead Nikita.

DR. SINGHAL: Thank you Chairman, Commissioners, the Commission and the Commission staff for inviting me to speak today and providing me with the opportunity to discuss on these issues that we're faced with. RTO and ISO market rules, practices and procedures are generally designed to enable and increase resource participation in ancillary service markets to enhance competition.

The bulk system operators generally their goal is to not discrimination against any technology, or resource, but they require that certain characteristics and capabilities of all service providers be met. The market rules should be technology agnostic in that any of these resources will need to satisfy existing performance requirements to qualify for service provisions.

Restrictions on participation for a specific service may be applicable based on product specific resource attributes. A failure to comply with well established performance requirements when such performance requirement are an eligibility criteria typically employed to qualify a resource's participation in the provision of ancillary services. And it is often based on a stability or reliability standard requirement. However it is important to ensure that such restrictions are based on attributes and resource performance that are founded on technically sound principles.

It is also important to regularly allow new and emerging technology to provide their performance and demonstrate that even to participate and meet these requirements through testing and certification. For instance, some ISOs do have certificates, and some emerging technologies that potentially consist of mixed resource types, restrictions in participation in a specific service may be applicable based on the technical capabilities, attributes, and performance of the most limiting resources in the technology mix.

For example, let's take the case of hybrid resources. These hybrid resources consist of storage and a variable resource component too. And if they were to elect to participate in the market using a single integrated resource model, the restrictions of participating in service may be based on technical capabilities, attributes and performance of the most limiting resource.

This limiting resource may be the storage component, or the variable energy component. In other words, eligible criteria may be dependent upon what the individual resources that constitute this hybrid resource mix are qualified to provide and able to provide. If the hybrid resource were to elect to participate as two separate independent resources two separate independent resources model, then each constituent technology will need to satisfy the existing energy eligibility requirements.

The variable energy resources may need to be curtailed to provide most ancillary services. Storage must have sufficient energy to provide based on the state of charge to provide most of these ancillary services.

Now another form of operation flexibility that was offered to these emerging technologies in the context of storage was specifically mentioned in FERC Order 841 which had to do with state of charge management. According to one of the requirements storage was allowed to self manage their state of charge, this is a very important operational flexibility that was provided to these emerging technology resources.

There was discussion by the prior panelists about the ability to update the offers closer to real-time, now the challenge there is that offers are allowed to be updated to closer to real time, but there is a discussion on whether or not there is enough time to mitigate those offers. Specifically, these offers that are updated closer to the real-time market window, about 60 to about 60 to 75 minutes, so if these offers are allowed to be updated closer to real time, will there be enough time to mitigate these offers?

That's where the questions are when it comes to updating offers as well. Thank you.

MR. SISKIND: Thank you Nikita. Before we go to the panelists responses, we first wanted to check and see if the Chairman had anything to say, and if not we'll move on to the Commissioners. Mr. Chairman?

CHAIRMAN GLICK: Thanks Aaron. Just quick I wanted to pick-up on Nikita's comment, and I wanted to ask maybe Jason, because I know we have limited time here, but maybe if you and maybe Betsy could respond. I'm just curious on the hybrid, I'll mention the hybrid resources. I'm curious about what changes you think might need to be made in terms of market rules given the benefits that the hybrid resource might be able to provide in terms of flexibility.

What changes do you think might be necessary to be made in the RTO/ISO market rules to further encourage the ability of those technologies to participate in ancillary services and energy markets for that matter?

MR. BURWEN: Thank you.

MS. SINGHAL: Thank you Commissioner. I'm sorry go ahead.

MR. BURWEN: Go ahead Nikita I think the question was for your first.

MS. SINGHAL: Okay. I was just going to say that the one change that may help us to allow these technologies to participate using multiple participation options. For instance, the one hour option which is being widely discussed in the industry, that allows for significant operation flexibility from the asset owner's perspective.

Whereas on the other hand the dual independent resource options allows for the unique characteristics of each technology that constitutes the hybrid resources to be monitored more accurately as well. So just having the multiple participation options itself maybe a good flexibility to have.

CHAIRMAN GLICK: Thank you.

MR. BURWEN: And then you know building on that I think that as Nikita noted that some of the concept of state of charge management being characterized in Order 841, that principal of sort of self-management I think carries through here on the hybrid resource side as well. You know I think where we are in some ways is that the asset manager has much granular visibility and control over its hybrid resources.

And that perhaps in a theoretical future you can have a market design that effectively optimizes those assets such that a hybrid resource operator would be satisfied that the way that the resource is going to be used or operated is going to be in line with what an operator decision might be in light of system needs and how do they get communicated.

But I don't think a lot of operators are there today, and that's probably part of the challenge here right is that the way in which you look at simply the day ahead versus the real time for these assets would be very different, and similarly you know the extent to which those components of the hybrid can be operated in an optimal fashion to meet needs seems to be from our members, for further clarity, limited in terms of what they are allowed to offer given the way that the market may choose to optimize those resources in its software.

And so I think that it's really a question of potentially where we are in the path of a transition to the higher computational granularity and complexity that I think is being implied by a number of different pieces of creating more flexible operations.

And so that at least in the interim if not for the whole long haul is probably a key principle to underscore for how hybrids can be enabled to provide their full flexibility.

MS. BECK: Yeah and I'll just jump in and agree certainly with both of the answers already to this question. We think that having multiple participation options is really important, whether that hybrid resource wants to participate in capacity, energy, or ancillary service markets as separate unique resources, or as a hybrid resource, having that option for us is really important.

I think it depends on the market what that resource is targeting, whether or not batteries in that hybrid resource is really being developed at the capacity resource, if the battery is really trying to target ancillary service products, depending on the region, and the market pricing incentives you may want to participate under different participation models and think that flexibility is important.

And another reality that we think about in how we participate in the markets is sort of the contracting and investment reality, the way that we contract and build renewables and variable resources today is still somewhat different than battery storage resources, and so sometimes there are sort of outside of the market limitations and realities of how we finance and contract these resources that impact the way we want to participate in the market with them as well, so we think it's important to have the flexibility for that reason too.

MR. SISKIND: Thank you. Did anyone else want to weigh in on this, or Mr. Chairman did you have any follow-ups?

CHAIRMAN GLICK: I appreciate the responses, but no I don't have any follow-ups, thanks.

MR. SISKIND: Okay. Commissioner Clements did you have any questions?

COMMISSIONER CLEMENTS: No. I'm fine thanks Aaron.

MR. SISKIND: Okay. Thank you. And just a real quick follow-up to this because I think we have kind of gone there already, if anyone else did want to respond to one of our next questions was going to be what market reforms could be adopted to ensure that these new and emerging resource types are able to offer their full operational capabilities into RTO/ISO energy and ancillary service markets.

If anyone wanted to say anything else here please now is the time, otherwise we will move on to our next question thank you. I guess you're up Robert.

MR. FARES: I do see a hand from Brian, actually Brian if you want to weigh in quickly.

MR. GEORGE: Yeah I just wanted to weigh in real quick, and I think this maybe goes back somewhat to Walter's point you know around maybe not necessarily maximizing the amount of flexibility, but incenting the most efficient flexibility on the system.

And you know I think that boils down to ensuring that asset owners know what capability is most valuable at a given time. And you know this points back a lot to some of the ORDC curve discussions right from the last panel. And so I think you know just making sure that those asset owners see when there's a system that's most valuable to the system I think will go a long way in incentivizing that most efficient flexibility.

And then the second point that I wanted to make, and this kind of follows on some of Jason's points you know around bidding parameters, I mean I think one thing that we're seeing right is that you know these certain things change depending on like state of charge. For example, ramp rates may be different based on where you know particular resources with respect towards stated charge.

So how do we think about allowing asset owners to reflect those changes in a way that does allow for effective market monitoring and mitigation, but ultimately conveys to the system operator that they do have this ability to provide that need to the system, so thank you.

MR. FARES: Thanks. And I think with that I will go ahead and move on to the next question that we want to cover. Hi everybody. I'm Robert Fares from the Commission's Office of Energy Market Regulation. I wanted to follow-up on a few points that were brought up in opening statements by Betsy and Walter and a few others.

And you know both of you discussed the fact that variable resources can be dispatchable and provide you know different services depending on where their dispatch point relative to their maximum potential energy output.

And you know I think your discussion is kind of interesting in light of the fact that you know folks often refer to variable energy resources as non-dispatchable resources, or inflexible resources when you know I think the reality is that you know based on your comments that they are capable of being dispatchable, but I wanted to drill in on that a little bit.

Could you just speak to kind of to what extent variable energy resources are capable of being dispatched up versus dispatched down, how this might kind of vary based on their particular operating situation, and try and distinguish them from sort of dispatchability that's provided by a conventional resource? And we'll start with Walter. Go ahead Walter.

DR. GRAF: Yeah thanks for the question. I'll kick it off, and then interested to hear other's thoughts. So I'm going to tell you these resources absolutely are dispatchable. In PJM we've been working on enabling intermittent and variable energy resources to respond to dispatch instructions. We're not 100 percent there yet, but we're working on it.

Just a few examples. So we leveraged SCED, security constrained economic dispatch, which has a two hour look-ahead period to dispatch wind. The objective here was to improve congestion control not provisionally to provide flexibility, but I think there are opportunities to enhance it to better meet that challenge.

This market design change introduced -- specifically introduced a new notification to wind units to indicate that they should explicitly follow PJM's dispatch to reduce its output, so they absolutely are dispatchable.

For solar there are more opportunities to improve dispatch logic in the SCED, I think we're not quite as far as we are there with wind. But for both solar and wind resources the objective is to enable the technical capability to be dispatchable, really to have that be available to the system. As to the distinction between being dispatched down and being curtailed, I think it's mostly semantics, but we understand how we have used those in PJM.

I think we tend to use curtailed when the operator picks up the phone and asks a resource to turn down, and dispatch when it's an outcome of the various economic dispatch engines that run at different timeframes. Of course to the extent that there is value to enabling that flexibility I think there absolutely is, we'd love to move away from manual operator actions to enable that flexibility within the economic dispatch engine, and we are moving in that direction in PJM.

MR. FARES: Thanks Walter. Next let's go to Mike DeSocio.

MR. DESOCIO: Thanks Robert. A good question and similar to what Walter was mentioning, New York has had renewables or variable resources on dispatch for quite some time. And we did that early on to make sure that new resources understood what we were looking for when they integrated and interconnected onto the system.

The way New York's model works is we take the approach that we're going to do our best to accommodate the wind or solar forecast output of the resource, and to the extent that resource is providing and maximizing its energy output, our market design is really designed around achieving that, which makes it difficult when you think about combining an intermittent resource with storage, because now you end up with some dichotomy on maximizing renewable output versus doing something different.

We use the term curtail because generally speaking there isn't an incentive for the renewable resource to hold back its capability so it could be dispatched up at a later interval, so we're really focusing on starting from a point of having that resource being at its maximum output, and then curtailing it, or dispatching it down to control the constraints. And we do that through economics. We aren't picking and choosing which resources to do that to schedule.

We look at security, constrained economic dispatch to make that choice based on its offer. And this is where it becomes very important that we think broader than just the competitive wholesale markets because the out of market payments to these resources become very important in considering whether there is really optionality for that resource.

When you think about having a resource hold back its output, it is now going to forego other payments, maybe a rec payment, maybe an ITC credit. And so, in order to do that, that means the wholesale market price needs not only cover that loss of revenue it needs to overcome that loss of revenue plus loss of energy capability.

So you talk about high hurdle rates from a cost perspective for these resources to do that because of other incentives outside of the wholesale markets. Now New York has been thinking and considering separating its reg up and reg down for a lot of the reasons that Walter mentioned that PJM is considering it.

We think there is opportunity at least to have requirements that may be more effective and efficient across the times of day. We do think there could be potential opportunities for renewable resources that provide regulation down in this case. And we also think that there's opportunities for other resources that may be at a PMIN to provide regulation up when today having a symmetrical product that is reg up and down, that resource would be excluded from.

So there's some opportunities there, but I think just focusing on the capability of the resource is probably not going far enough when thinking about whether there is value in providing such a feature.

MR. FARES: Thank you. Next let's go to Nikita Singhal.

DR. SINGHAL: Thank you. I think Mike covered it the questions really well. But technically there is no distinction between being dispatched down and being curtailed. The two are synonyms, but one has typically carried with it a negative connotation.

The overarching goal should always be to ensure that the resource is operated in the manner that's most effective from a system perspective, and to devise ways to incentivize it accordingly. Now there may be instances in which stand-alone variable energy resources may be needed to be curtailed to allow reliable operations or dispatched down to accommodating system conditions.

Now from a technical perspective the variable energy resources may be curtailed or dispatched down either due to transmission congestion, either due to what could also be low load or minimum generation constraints, or to ensure that there is sufficient available rampable capacity available to accommodate future instances of unavailability from the variable energy resources.

For instance due to limited options to manage transmission congestion sometimes variable energy resources need to be curtailed to relieve that congestion. Now during those instances VERs must be dispatched down or penalized. Given that these facilities also earn additional revenues from production based mechanisms independent of wholesale electricity market revenue, typically there are limited economic incentives for these resources to provide upward reserve service, such that it require the resource to be backed down or subject to forego energy sales given production tax credits for instance.

Typically the economics that impact the availability of variable energy resources to provide upwards response because there are very few instances and conditions when it may be economic to dispatch a resource below its forecasted upward operating limit. For example, curtailing or dispatching down a variable energy resource to provide ancillary services may reduce the need to commit an additional resource.

This results in accompanying system benefits in the form of reduced commitment costs that are potentially not always reflected in prices. Otherwise, a majority of the instances due to the zero marginal costs and the negative offers, these resources are typically scheduled at their upward operating limits, thanks.

MR. FARES: Thank you. Next let's go to Betsy Beck.

MS. BECK: Thanks. And I think the previous panelists mostly covered it well. The only thing that I wanted to reiterate was that yes, new and modern energy storage, wind and solar resources are very much dispatchable and do follow market dispatch signals.

Typically as was mentioned because they are going to be the lowest cost marginal resources, the system is just mirroring what the actual output of the plant is at any given time unless of course there is a dispatch down, or a curtailment signal sent at which point all of the automated dispatch signals go to the renewable plants, and they can respond very quickly.

And as I think I mentioned in my opening comments SPP did, and other markets have required resources to convert to be dispatchable, so some of the older legacy projects that were originally built, you know, a decade ago, did not have the full dispatchable capabilities, but have since converted you know, spent the money and invested in the upgrades necessary to put those systems in place to become dispatchable.

ENEL just completed this process in SPP for several hundred megawatts of wind that were some older projects, and at the beginning of 2021 we did become compliant with that new requirement, and now have a fully dispatchable fleet. And I believe the vast majority of wind in SPP has completed that conversion to date, and so that's great for the operators to now have that increased ability, and again it was a costly endeavor for some older resources, but something that we were able to make the investments and retrofit to accommodate.

But again, everything that's being built now is already being built with those capabilities. But I did want to mention again one thing that I mentioned in my opening comments was that when wind or solar for example is curtailed, and then the curtailment is released, those resources are able to come out of that curtailment and start generating again up to their full capability at that time in the matter of you know seconds, not minutes.

And so that is a place where you see those ramp rate limitations come into effect because you know prices go up. They want to release that curtailment on the resource, and the resource wants to respond quickly to respond to those price signals, but is limited often times by the use, by these ramp rates, even though they can respond much more quickly. Thanks.

MR. FARES: Thank you Betsy, and all the panelists for their responses to that question. I wanted to follow-up, I mean considering a number of you mentioned the fact that the incentives really aren't there, just based on you know prevailing market conditions for a zero marginal cost resource to hold back its potential output in order to provide an up ramping type capability.

How do you see that potentially changing as the penetration of the zero marginal cost variable resources increases? Would that create a greater incentive potentially for resource owners to provide some of these up ramping capabilities? And I think either way, or if so, what market rule changes might be necessary in order to accommodate that, thanks. Mike?

MR. DESOCIO: Robert I think your question is a really good one, and I wish I had my crystal ball to be able to give you the answer that we'll all see in a few years. I think the ability for the wholesale markets to overcome the out of market incentives that exists is going to be really challenging.

And I look at that in the face of the amounts of procurements that are being signed up by various states to achieve their local policy goals. I'm not suggesting that's a bad thing, it's just the incentives that will be outside the wholesale market in those cases will just be very large.

And it's not clear to me that it would be more advantageous to try to get other services provided by these renewable resources rather than investments in other types of technologies like energy storage or other flexible resources that may be more advantageous to fulfill you know the energy droughts that we're going to end up having when some of these resources aren't around.

And in those cases I see that modifications to reserve requirements, New York is focused on developing ways to dynamically determine the reserve requirements, not only based on a deterministic loss of the largest resource, but also on the probabilistic loss of a swath of offshore wind plants, or a swath of land based wind plants because now the contingency isn't the loss of a 2,000 megawatt nuclear reactor, it's the loss of 50 percent of 10,000 megawatts of offshore wind.

And that loss is much bigger, and which would create upward pressure on the need for reserves and meet their pricing. And I think when I think about those things I don't envision that you'll see the economics of curtailing renewable resource to provide that being the most effective way to manage. I see other resources really looking to fulfill that gap. Thank you.

MR. FARES: Thanks Mike. Next why don't we go to Jason Burwen.

MR. BURWEN: Thank you. I wanted to just follow-up on what Mike was saying when he started saying what I was going to suggest here right, this in a high renewables future, a temporary reduction in output from wind and solar and a forced outage from thermal generator are going to become more and more indistinguishable, but the services to provide the flexibility for each of those two situations currently varies right?

And so this is I think the heart of this question, how do ancillary services maybe need to evolve, you know, contingency reserves are event driven, but higher renewables where we might need these to be more continuously deployed at varying time scales for reserve windows, this is what I think what I mean by flexibility reserves, a concept that folks are covering in papers.

I know the Renewable Energy Buyer's Association's report on designing a 21st Century electricity system sort of is diving into this. And so that change is going to be very important one, to make sure that we're actually working with the higher renewables future and the system has conquered that based on that change to how we think about outage and change of output, but this gets back to also I think the same question of how you value flexibility.

And Mike makes a very good point. Not only do you observe marginal properties with the out of market payments are going to make it that an energy price reference for such services becomes increasingly challenging and problematic for actually providing that single value to that.

I agree that in fact in some ways it almost forces without the evolution of ancillary services, the highest formation associated with it forces you into a world of thinking about how do we change that behavior of the variable renewable generators.

And I think the way I would describe this is that you actually have multiple paths out of that question which is focused on changing the variable renewable generators behavior, the others is focused on the market products price formation.

MR. FARES: Thanks Jason. Next let's go to Brian George.

MR. GEORGE: Yeah thanks. I mean I would just add real quickly I mean I think that this goes back to the point of making sure that we're designing our markets around the capabilities that we need. I mean to the extent that resources can provide those services, that's what we should be going for. And I think you know in addition to the point around you know zero marginal cost.

I mean I think that's where it becomes all the more important if what we're doing is actually providing an investable signal for folks to develop the resources that have the services that are needed, and that's you know I think why we need to look at not just these changes with respect to the ancillary services markets, but also with the energy markets, and ultimately the capacity markets where they exist, so that we are you know providing folks with the right investment signals to make sure that we are deploying resources with these capabilities that we know we're going to need, thank you.

MR. FARES: Thanks Brian. Next let's go to Betsy Beck.

MS. BECK: Sure. I just wanted to build on one comment that Mike made a little bit which is that as we think about what the systems needs in an increasing grid with more renewable and variable resources, and we think about the contingency and what ancillary services and reserves are needed. You know we think about the offshore wind you know losing a large portion of that.

We're not, you know, we're not expecting to see that like trip off line the way we would think about a conventional resource tripping, rather the things we need to be planning for are uncertainty in forecast. And there it's a little bit different timeframe, and it's a little bit different problems and it means that we're going to need to start shifting to plan for.

So it's you know it's different than deviations from the day ahead to the real time forecast, or it's a weather system that's shifted you know 100 miles in one direction, but that we have you know a bit of visibility into maybe a few hours, or 30 minutes in advance.

And so you know as we think about what's happening you know around weather dependent resources, it's less of an unforeseen you know tripping of a resource, but rather you know how can this system have the ramp that it's going to need as we expect you know wind or solar to perhaps have a steep ramp, which again is something that we have -- are getting better and better at forecasting.

And so our ancillary services and reserve products need to perhaps shift in their timeframes, and what they're looking at to plan for these different types of events that are going to occur in the higher renewable penetration future because they are inherently different from the types of events that we have planned for on the system historically.

MR. FARES: Thanks Betsy. Next I want to go to Walter Graf.

DR. GRAF: Yeah thanks for the question, and great discussion so far. I wanted to second Mr. DeSocio's comments regarding the distortionary effects of out of market revenues. This is just a disconnect between what some of these policies ultimately report to value, which is displacing carbon and what they do, which is paying for megawatt hours of clean generation even when that generation does not displace carbon, but it may well displace other low or zero carbon resources.

That disconnect really does introduce difficulties into the wholesale market, and it's a difficult problem, one that we have yet to resolve. I do want to agree with the other comments that other panelists have made, but I wanted to add one more thought regarding how do we value that flexibility.

First, this is not a fundamentally different problem from that which our markets have been designed to address, and I would say have done a reasonably good job of meeting that challenge. Uncertainty, whether driven by changes in load, or changes in thermal, or intermittent resources is not a fundamentally different problem.

I think that we should not be looking for fundamentally different solutions. And second, I'd like to suggest that the increasingly variable and volatile prices that we get under the type of future that you described will themselves incentivize flexibility because those resources that can best capture those high priced periods are those that have flexible capabilities and are operated flexibly.

MR. FARES : Thank you Walter. Next let's go back to Mike DeSocio.

MR. DESOCIO: Thanks Robert. I think Walter covered a lot of what I wanted to say, but in response to others that have pointed out desires to focus on capacity market reforms to create flexibility or flexibility products, I'd encourage us to maybe step away from that paradigm, and instead focus on making sure we're valuing capacity resources appropriately.

I think capacity accreditation is one of the more important things we could be doing with the capacity market to make sure we're incenting the fleet that we need to manage the grid of the future, and certainly New York is focused on that right now, and looks forward to continuing to evolve that, thanks.

MR. FARES: Thanks for that closing comment Mike. I think with that I'll turn it over to my colleague Aaron to close us out.

MR. SISKIND: Sure. First I wanted to check and see. Chairman Glick did you have any final comments for this panel?

CHAIRMAN GLICK: No. Other than to thank the panelists. This has been a very interesting discussion.

MR. SISKIND: Thank you Mr. Chairman.

Commissioner Clements did you have any statements?

COMMISSIONER CLEMENTS: No same, thank you for the participation. Really interesting conversation and helpful.

MR. SISKIND: Okay. Well thank you Chairman, Commissioner Clements and all of our panelists. I think this was a really great discussion. This concludes our panel here. We'll now take a lunch break and we'll be back at 1:30. Panel 2 panelists please sign out of the Webex meeting.

If you would like to continue watching the conference you may use the link, the public link available at ferc.gov. Chairman, Commissioners, panelists for Panel 3 please be on the line at 1:15. We'll run through the technical logistics at that time to make sure everyone's able to connect. Thank you and have a fun lunch.

(Break 12:27 p.m. - 1:30 p.m.)

Panel 3: Revising RTO/ISO Market Models, Optimization, and Other Software Elements to Address Operational Flexibility Needs

MR. SMITH: Hello. Welcome back from lunch and thank you for joining us. My name is Alex Smith, and I'm with the Office of Energy Policy and Innovation. My colleague Tom Dautel, also for the Office of Energy Policy and Innovation and I will be co-moderating this third panel.

This panel will focus on potential changes to RTO/ISO energy and ancillary service market models, software and operational practices to optimize the changing resource fleet. Discussion in this panel will refer to RTO/ISO software used for market clearing and pricing of energy and ancillary services, and any software supporting that function, including software for advisory commitments, look ahead commitments, and resource modeling among others.

In addition to the panelists which I'll introduce shortly, I'd also like to welcome Chairman Glick to this panel. Before we start the question and answer session I'd like to once again remind all participants to refrain from discussing the specific details of the pending contested proceedings listed on the supplemental notice, and to refrain from discussion any other pending, contested proceedings.

If anyone engaged in these kinds of discussions, my colleague Adam Eldean from the Office of General Counsel will interrupt the discussion to ask the speaker to avoid that topic. And before I go further, I should also welcome Commissioner Clements to the panel. Thank you for joining.

I will call each panelist in turn to give their response to our first question. I ask that panelists limit their initial response to no longer than five minutes. Our question is what are the challenges to incorporating uncertainty within the current RTO/ISO market software?

For example, how can improvements in forecasting be used in the intraday commitment processes that include a range of forecasts or a longer look ahead commitment and dispatch horizons result in a more efficient unit commitment and dispatch in real time? Panelists please answer this question, and in turn I'll call on you by name. And I'll start with Dr. George Angelidis.

DR. ANGELIDIS: Hello and thank you. Can you hear me okay?

MR. SMITH: Yes, thank you, please go ahead George.

DR. ANGELIDIS: Thank you. So the challenge incorporating uncertainty in the market is two-fold. First of all you have to decide a market commodity and procure it and reserve it in the market, so this particular task requires a multi-interval of optimization because this commodity is only reserving ramp capability from one interval to the next, so that this ramp capability can be available and deliverable in the next market ramp where uncertainty potentially materializes.

And the second aspect is you have to come up with a reasonable methodology for calculating the uncertainty requirement without tremendous effort because you have to do it constantly as the market ramps update the requirement.

So for that you need to harvest historical uncertainty data, and regress this data along with the current forecast that you have available for its application, synthesize the regression results and come up with an uncertainty requirement.

And for this work you could take a simple approach of calculating a regression on a single regressor like the net demand forecast which is your demand forecast reduced by solar and wind forecast, or you can take a more elaborate approach which is more accurate, and do it over three regressors separately as we do it in the California ISO where we handle demand forecast, solar forecast and wind forecast as separate regressors, so we harvest the data separately, and then we regress it all together to come up with the uncertainty.

And we use a 180-day rolling horizon for calculating this uncertainty, the requirements calculated for each balancing authority area in the energy imbalance market, so that's a static calculation that repeats every day, but there is also a dynamic component that you have to calculate this on the fly for every market ramp because we have a process for where we procure this ramping product, we call it flexible ramping product for the group of balancing authority areas that pass a resource sufficiency evaluation test.

And this can change for every market run, so you also have to do this dynamically, so it's really performance intensive. So that's one of the biggest challenges that we're facing. Thank you.

MR. SMITH: Thanks very much George. Next I'll call on Dr. Erik Ela.

DR. ELA: Great. Thanks Alex, and thanks to Chairman Glick, FERC Commissioners, and FERC staff, including Emma and the team for inviting me to participate today. So just a quick background. EPRI conducts R and D on behalf of the electric sector, and one of the areas that we have supported in recent years is on electricity markets, and electricity market clearing software.

Through advanced simulation analysis we look at the potential advantages and disadvantages of emerging market designs, operational strategies and software implementations, and provide those insights back to the RTOs and stakeholders in the hope they can be useful in determining design and implementation decisions.

So in regards to the question of incorporating uncertainty, I think there's some information that's useful to start with that I think we'll hear from other panelists potentially as well. So forecast, day ahead forecast for load, wind, and solar that are you know utilized by the ISO are currently only used in the reliability unit commitment process, which is called the RUC, sometimes the RAC reliability assessment commitment, or forecast path, et cetera.

These processes primarily are run after the day ahead market with a primary focus of committing sufficient resources that require a day ahead notification time while minimizing the residual unit commitment costs. So resources committed in the day ahead market are not de-committed. If for example, the renewable forecast is higher than the renewable bids, in addition is often the case that the energy costs are ignored, so the incremental energy costs are ignored or largely discounted, so that only the commitment costs are of concern -- things like startup costs and no load or minimum generation costs.

This implies that improved day ahead forecasts of load and renewables have somewhat of a limited impact on economic efficiency in a direct sense. That said it is important to consider that improved forecast can improve efficiency when these are used directly by loads, you know, market participants, renewable resource assets, as well as financial participants, such as virtual traders when these forecasts are used in their offer strategy.

So moving into real time and the real time dispatch and most other intraday processes such as the intraday reliability unit commitment, or real time unit commitment. In these cases forecasts are used more directly in the ISO processes, so the ISO gets these forecasts for individual resources, or for load zones for example, and uses them directly into the scheduling processes and into the market clearance software.

So this means that for forecasts and other enhancements of forecast applications such as a longer look ahead horizons, or multi-scenario forecast utilizations, can have a more direct impact on both reliability and economic efficiency, so those are some of the comments I wanted to start with in terms of uncertainty and use the forecast and look forward to the rest of the session. Thank you.

MR. SMITH: Thank you so much Erik. Next I'll call on Dr. Bethany Frew.

DR. FREW: Great. Thanks Alex. It's an honor to be on this panel. I'm a researcher at the National Renewable Energy Laboratory, and I'm going to be providing some opening remarks to this discussion on uncertainty from a strong computational modeling perspective.

Drawing from various studies that we've done collectively at NREL over recent years, but I'll note that we are actively doing more work in this space to continue exploring specifically the role of forecasting accuracy and look ahead. So first related to forecasting improvements it probably goes without saying that better forecasting make things more efficient, specifically from a production cost and curtailment perspective.

But the value of improved forecast depends on both the amount of renewables, and thermal units in this system. And so we've seen consistently across different studies, almost a transition zone where as you start to increase the amount of renewables on your system, specifically variable renewable resources like wind and solar, and you start to reduce the amount of thermal units in the system, there's sort of this transition beyond which unit commitment related impacts can be diminished.

And so specifically start-up costs are one of the areas where we see a lot of value of improved forecast, whether as you remove or many of those thermal units could be retired in future scenarios, the value of those improved forecasts decline. So there's really this interesting kind of interplay between what's happening in the rest of the system, and the forecast quality.

There's also a bigger issue of time scales with this conversation on forecast improvements where forecasts and improvements of them won't do much good unless the time scales of those forecasts are explicitly synched to some sort of decision process in the system.

Secondly, related to the look ahead topic we've also found repeatedly in our grid integration studies that the look ahead extent and the resolution can significantly impact trade-offs in the operating reserve and unserved energy penalties, as well as start-up costs specifically of peaking generators as well as infeasibilities as the model sees it.

Storage is particularly sensitive to these look ahead settings, and so there's really a strong link between the information quantity and the granularity, at least again from a modeling perspective. So beyond these two key topics that we're focusing on of forecast improvements and look ahead, there's also from a more market design perspective, we found that there are often multiple ways to achieve the same end results.

And I know others in this panel have been working this space. Erik at EPRI comes to mind as one, but there's various products, there's rules, there's pricing mechanisms, the data issue itself and any better quality data, there's the operational sequence and frequency which gets to the multi-interval point that's been mentioned a couple of times. Even out of market mandates, and even other technologies where there can be trade-offs for example with storage, demand response and transmission to provide flexibility for the system.

And so there really needs to be a process to identify and assess these various options for specific systems, and specific futures to understand which combinations, or which items might be best suited for those particular applications. And ultimately, I think what we're getting is a trade-off between better information, and increased computational burden, and getting better quality data is not a trivial, or a free task.

And I say that from both a research perspective where it's a heavy lift to get better data, improved forecast, increasing the granularity of our models, having additional look ahead horizons, or additional intervals over which the operation of the market is clearing.

And it's also true for continuous day to day operations which has been mentioned at least once in this conversation already on the need to kind of do on the fly calculations. So just wanted to end with that point, and so there is this kind of trade-off question that I think has to be discussed. Thank you.

MR. SMITH: Thank you Bethany. Next I'll call on Dr. Congcong Wang.

DR. WANG: Thank you to the Commission for hosting this event, and for inviting me today. At MISO we are looking at a variety of ways to address growing uncertainty and variability, including approaches posting this question. I'd also like to broaden the discussion somewhat beyond those measures.

First and foremost, in our minds, characterizing uncertainty correctly is one of the largest challenges and the quickest needs. Before we figure out how to change our commitment dispatch model. Once we figure that out then we can integrate flexibility into the optimization model either through reserve products, stochastic or robust optimization, or combination, but each approach has its own challenges to clearly reflect the operational needs.

And finally, almost all of these approaches contribute to increasing computational. So regarding uncertainty characterization the inputs we give our commitment dispatch engines define the problem we are asking them to solve. So we really need to have a good handle on the uncertainty, otherwise as the saying goes garbage in, garbage out.

This entails collecting not only forecast, but also their confidence intervals, and understanding their co-relations and aggregating them in a timely manner. The problem is becoming harder as uncertainties increase in intensity and a variety. As we are hitting the 30 GW mark of wind and expecting record growth of solar, the variety and uncertainty are coming in greater volume.

But it's not just about growing forecast errors, for examples, in that scale interchange, transmission and generation outages, and fuel availability are all moving parts, and the changing weather patterns are making things harder to predict.

So furthermore, uncertainties correlate, and their impacts differ across time. We have experienced extreme ramp challenges on days where underestimated a steep wind drop with the evening load ramp then resulting in the almost 600 MW lost every 10 minutes, then that's almost equivalent to a loss of a large, combined cycle every 10 minutes for over an hour.

So a priority for us is really to improve forecasts and particularly to quantify and aggregate uncertainties. With uncertainties characterized flexibility needs can be accounted in the commitment dispatch model, and that is primarily done through reserve products. However, operations manage uncertainty throughout the day, or even day or days ahead.

We are exploring a new whole existing, or new flexibility products each with a defined timeframe aligned with our operational flexibility needs, and how different products can work together to address the evolving uncertainty across time. Our unique regional situation further emphasize the challenge of the deliverability of uncertainty.

Unlike energy where we model the transmission, the regional transfer limits explicitly reserves are not allocated on a granular basis, so we can run into the risk of obtaining reserve in one place, but not deliverable to where it's needed. We are currently working on the issue of reviewing the reserve requirements and enhancing deliverability.

We are also looking into stochastic look ahead commitment to manage flexibility, however those scenarios, especially if we combine with a longer look ahead horizon, you increase the problem size significantly. The computational time then where it will become a major issue as it increases exponentially with the problem size.

Along with the unit commitment approaches we are also exploring best practices for selecting scenarios and improving computational time. And getting the time right is critical because operators have strict decisions making timeframe as resource flexibility diminish due to their start up and notification time, ramp rate et cetera, and this is particularly hard for our footprint with a tightening supply margin and good portion of long-lead units.

So incorporating uncertainty into the market software is promising, and it's needed. However, we must start by correctly characterizing the uncertainties. The commitment dispatch problem will become harder to manage with a varying flexibility needs across time as well as geography.

So finally, almost all of these changes contributed to an increase in computational challenges. So I look forward to more discussion today. Thank you.

MR. SMITH: Thank you Congcong. Next I'll call on Arne Olson.

MR. OLSON: Thank you for the opportunity to come here today and present some thoughts on ancillary services. I'm Arne Olson, I'm a Senior Partner with E3. I'm going to start with maybe some broader brush recommendations from our work, years of experience in market design, transaction support, and energy systems modeling, both for the existing power systems, but also future systems under a trajectory toward deep decarbonization.

Our views on ancillary service market reforms are summarized in our recent white paper called Scalable Markets for the Energy Transition that which I'll file in this docket. In that paper we consider reforms that are needed to efficiently and reliably scale clean energy. We observed that the grid's need for energy and capacity and grid services, will remain the same under very high levels of clean energy resources.

However, the nature of the resources that provide those services will be very different, and markets must evolve to optimize the use of these new resources. In particular, inverter based resources such as wind, solar and battery storage, have the capability to respond very quickly -- much more quickly than conventional resources to dispatch signals.

But they can only offer that capability at certain times, and their cost for doing so is based not on direct out of pocket costs, like for conventional resources, but on lost opportunities to sell energy contemporaneously, or in the future. Fully optimizing these resources based on grid conditions will be critical to ensure reliable and cost-effective transition.

So recommendations for ancillary service markets are four fold. First, market operators must develop scientific methods for determining the quantity of ancillary services needed based on continually changing grid conditions. There are initiatives underway at EPRI, at E3 and others, some of them including our own funded in part by ARPA-E to develop software that projects net load uncertainty across multiple time steps as a function of changing load, wind, and solar forecast error using advanced computational techniques such as machine learning.

And we think these models can help reduce costs by identifying periods in which grid conditions are stable, and lower quantities of reserves are needed. And increase reliability by identifying periods in which higher reserves may be needed.

So just as an example when wind and solar production are very high, there's little need to procure downward reserves in case production goes up even further, and conversely when wind and solar production are very low, there's little need for upward reserves in case production drops further.

Second, market operators should take steps to ensure that inverter based resources are bidding their full range of capabilities into the various markets. Wind and solar projects can be dispatched downward, all the way to zero, nearly instantaneously. They can also be dispatched upward, but only if they're producing below the maximum potential. They should have the capability to bid both upward and downward flexibility, with bids reflecting their opportunity costs of lost sales of energy and clean energy attributes.

Third, upward and downward reserve products should be specified and procured separately. Wind and solar projects have asymmetric cost functions for providing upward and downward reserves. The cost for providing downward reserves is only the lost revenue that is experienced during the few real time intervals in which the resource is actually dispatched downward, whereas the cost of providing upward reserves is realized immediately in reduced hourly energy revenues for the entire megawatt quantity offered, and is only partly ameliorated when the service is dispatched upward in real time.

Energy storage may also have asymmetric opportunity costs for the provision of reserve services. If owners expect energy costs to increase during the project's storage horizon, their cost to provide upward reserves is a function of their lost opportunity to earn additional arbitrage revenue by charging now at low cost.

And conversely, if they expect prices to go down, they'll be willing to provide downward reserves only if the price is compensatory with the lost revenue from delayed discharge. And these values can be very different at any given point in time.

And finally, and most ambitiously we should look to market software to optimize the use of energy storage. It's the most flexible resource available in the market, but it's costs are entirely defined by market opportunities to buy low and sell high. As substantial quantities of storage are added it will be increasingly important for market software to optimize its use, meaning that in an ideal world we would allow the market software to determine when energy storage is charged and discharged on a daily basis.

We should look to the market software to determine which reserve products are provided by energy storage optimally, and lastly the market software should be able to calculate endogenously in the energy storage opportunity costs based on market clearing prices for energy and ancillary services, and fully compensate the project's owners for the value of all services provided.

So those are my opening remarks, and I'm really looking forward to the rest of the conversation. Thank you.

MR. SMITH: Thank you Arne. Next I'll call on Dr. Jinye Zhao.

DR. ZHAO: Good afternoon everyone. I'd like to first thank Chairman, Commissioners, and Commission staff for inviting me to participate in this very important technical conference. So as I listened to the opening remarks of other panelists I realized some of the comments I had prepared at first, may reflect other panelist's views, so I apologize. It may seen a little repeating of what others have said.

So in order to manage uncertainties during operating periods we need to address two main questions. So the first question is how to reduce the magnitude of uncertainties. So in other words it's how to reduce the problem size. And the second question is given that there are always uncertainties in the system, so what solution strategies can we use to manage uncertainties.

So let me start with the first question -- how to reduce the magnitude of uncertainties. I think improving forecasting would be one of the most direct ways to reduce uncertainties, so without a good forecast we would have a garbage in, garbage out problem. You know commitment and dispatch process. Congcong also mentioned that when she spoke, and in addition to reduce uncertainties, ISO New England also implemented do not exceed limits.

We also call it DNE limits, so we use that as a dispatch instruction for renewable resources. The DNE limits allows us to maximize the usage of extra renewable generation above the forecast value, but at the same time cap the generation below a level that won't violate system reliability.

But however, uncertainty is in the DNA of power systems, no matter how we reduce the size of uncertainty, there always exists unexpected events, such as contingency, generators not following dispatch signals, and with the climate changes, power systems are likely to be exposed more frequently to large uncertainties under extreme weather events.

So therefore it's important to develop uncertainty management strategy which leads us to the second questions. So there are multiple ways to manage uncertainty in the market software, and in previous panels have listed a few very good approaches. So I view these approaches can be separated into two buckets.

So one is the deterministic approach. So the industry has been using 10 minutes and 30 minutes reserve products, and also has adopted some new ancillary service products such as ramping and flexibility products to cope with uncertainties. And these are reserve and new ancillary service products can be considered as deterministic approaches, so they are straight forward, and also computationally efficient.

They serve well to simplify the decision-making process in time critical applications. However, the drawback of the deterministic approaches is that if the number of random variables and system complexities are greatly increased, then collapsing all the set of possible future outcome into a single reserve requirements, or ramp flexibility requirements may not be a very effective way to handle uncertainties.

So besides the deterministic approach, then there is probabilistic approaches. So the probabilistic approaches includes scenario based stochastic optimization, robust optimization, and these approaches have drawn a lot of attention because of their capability to explicitly model uncertainties in the dispatch, in the commitment problems. However, the stochastic and the robust optimizations are still computationally challenging.

So they are not quite ready yet to be used in productions. And in terms of the look-ahead horizon, I think a longer look ahead commitments or dispatch horizons is always beneficial for scheduling resources to manage predictable changes in theory. So especially when we have a system is time-coupled through ramping energy storage resources, as well as limited energy resources.

In this case look ahead, have a longer look ahead capability is very important. However, the issue with look ahead optimization is the further out we look ahead, the more uncertainties we have right? So it becomes very difficult to know the effect of a decision you made ahead of time without a perfect forecast foresight.

So some decisions made early may not be efficient or reliable when uncertainties is materialized. So in summary, different ways can be used to mitigate uncertainty risk, and some methods may be more effective than others, but depending on the magnitude and time skills of uncertainties.

And because each region has its own unique characteristic in the resource mix, and ISOs and RTOs face different uncertainty challenges, so there's no one size fits all solution. And as each ISO and RTO develop a set of solution methodologies which are suitable for its own regional needs, and I also think it's very important that we learn from each other using the opportunity like today's conference. So I really appreciate the other panelists for sharing your insights on this topic today, and I look forward to the panel discussion. Thank you very much.

MR. SMITH: Thank you Jinye. I'll now turn to the Chairman and Commissioners for any questions they may have starting with Chairman Glick. Mr. Chairman you might be on mute. We can't hear you.

CHAIRMAN GLICK: I'll try it again. Alex I just want to thank you, but I don't have any questions. Can you hear me?

MR. SMITH: Yes perfect, thank you so much.

CHAIRMAN GLICK: Thank you.

MR. SMITH: Next Commissioner Clements do you have any questions?

COMMISSIONER CLEMENTS: I do not at this time, thank you very much.

MR. SMITH: Thank you. And Commissioner Christie, thank you for joining us. Do you have any questions?

COMMISSIONER CHRISTIE: No questions at this time. Thank you very much.

MR. SMITH: Okay. Thank you so much. In that case I'll ask if our panelists have any further comments they'd like to make in response to question one or any of the other panelists responses to question one, please -- are the list for hand raises in case anyone wants to say anything further. George I see your hand is raised. Please go ahead.

DR. ANGELIDIS: Yes thank you. And Jinye just mentioned that when you have a multi-interval optimization for having a look ahead which provides you the ability to first of all procure flexibility for the next market run, you need to have a look ahead. And also provides you the ability to make some short term unit commitment which is very important to position resources for what your market horizon can see for future intervals.

There is this trade-off between performance and accuracy. Of course it's clear that the longer of the time horizon, more intervals you have to solve, that's the performance intensive part, but then you have to trade this off with what accuracy can expect to have too, so yes further into the future your uncertainty is greater, so system conditions can only be forecasted to a certain extent, but you have the benefit with the longer time horizon to actually perform some higher quality, short-term unit commitment because you'll be able to cycle more resources.

The resources that are intertemporal characteristics can fit into the time horizon. You want to capture and model accurately the commitment costs, so for that purpose their startup time and their minimum Up time has to contend with your time horizon. In the California ISO we do have once an hour we run a short-term unit commitment application that looks up to 18 15 minute intervals.

That's four and a half hours, so we are capable with this application to perform some sort-term unit commitment to the next coming hours for a number of resources that's in the system.

Regarding the uncertainty which makes this process a little bit nebulous for future hours, particularly when you reach to the edge of the time horizon, this is only one part of the problem. The other part that is also problematic is usually for this long-time horizons your bids that you have for market participants for further hours out in the future, they haven't been finalized yet. You don't have financially binding bids.

They're still advisory because the market still offer for those future hours. It could be revised, or you don't even have all the bids submitted. So it's really a challenge in the trade-off trying to balance everything, trying to have as long a time horizon as you would like to, versus the accuracy that you can hit with later hours. And that was what I wanted to comment on that, thank you.

MR. SMITH: Thank you so much George. Do we have any further comments from any of our other panelists? Okay Jinye I see your hand is up, please go ahead.

DR. ZHAO: Okay. Yeah I agree with that George's comments. I feel definitely there is a benefit for having a longer look ahead Horizon, and I feel one other way to sort of handle the uncertainties issues in the longer horizon is what we can do is do more frequent commitment run or dispatch run, so as the operator getting more updated information, and I think we should put this information into the commitment decision as well as dispatch decisions so that the commitment is issued and dispatch run can utilize the updated information and make more informed, more efficient decisions so we don't keep dispatching the system using the outdated information.

And I also wanted to add I recall another comment I think brought up earlier by one of the panelists is that the reserve quantities right. So I heard it's very important to start off a historical information to produce a better reserve requirement, so I fully agree in that because so for that case the power system has a set reserve requirement to reflect the largest contingency, or the second largest contingency.

So it seems we are constantly using the same reserve requirements all the time, all day, and however with the increasing uncertainty level in the system, I think we need to rethink the definition of reserve requirements. And I think it will be useful that the operator take into account the available information to them, and sort of understanding whether the system is at a low risk or a high risk state, and correspondingly adjust the reserve requirement to properly reflect the system uncertainly level. Thank you.

MR. SMITH: Thank you Jinye. I see Arne your hand is up. Please go ahead.

MR. OLSON: Yeah I think I thought I might just add on to that a little bit, that you know this is where we see things like machine learning being potentially a good way to kind of bridge the gap between you know, obviously ideally you would be able to do stochastic unit commitments, stochastic dispatch, taking into consideration all of the potential future states, and finding an optimal path through them that minimizes costs across the whole distribution of potential outcomes, but that's you know, very, very confrontationally intensive.

One way to maybe bridge that gap is to use the best available historical information continuously updated with tools that continually learn from historical information that based on this state of the system, this is where sort of a P95 or a P5 stage for a net load in the next interval might be, and the next interval after that, and the next interval after that, and the next interval after that.

So you might think of it as like an envelope of net load uncertainty over successive time steps all the way up to you know five hours, eight hours, whatever the sort of farthest horizon is that's needed. And so taking that information into consideration when looking at residual commitment, and perhaps even formalizing that as a reserve product to reflect the sort of option value that the system operator needs to be able to call on for head room and foot room, upward dispatch, downward dispatch, as a way to bridge that gap with tools that can continuously learn and continuously get better over time as more and more data is added.

Another -- the last point I'll make there is in the past kind of separated this contingency reserve which you know, as Jinye mentioned, is typically based on the largest single contingency on the system from a regulating reserve which is meant to deal with kind of short-term minute variability.

Those two things are going to increasingly get closer and closer to the same thing. They're going to be more continuous and less discrete as we have more dispatchable resources or non-dispatchable resources, more variable resources on the system. So large wind events, wind down ramp events might start to look like large contingencies, and there may be you know wind down ramp events that are less large than your biggest contingency, but it's still big, and some that are pretty big, but not as big as your next one.

So there's going to be a lot more of continuous range of these types of conditions that we'll need to consider. And so I think some form of formal ancillary service product that's in between regulating reserves and contingency reserves that's dynamic that reflects changing capabilities, or changing needs on the system is a promising way to kind of bridge that gap.

MR. SMITH: Thank you so much Arne. Any further comments from our panelists? All right. Seeing no further raised hands I'll now turn to Tom Dautel to ask our second question. Tom please go ahead.

MR. DAUTEL: Thanks Alex. I'm moving to the second question in this panel in our agenda. And noting that I think we've covered some of that material already, so just in the interest of efficiency and time management, I was going to focus in on one part of that next question. So the question is how would multi period dispatch modeling in the real time market help address operational flexibility needs, and what are the advantages and disadvantage of a binding, as opposed to an advisory multi period dispatch or unit commitment model?

And if you want to answer just raise your hand as you did for the previous question. Okay. I'm not sure who was first, but Erik I think I saw you pretty quickly.

MR. ELA: Yeah thanks, thanks Tom. So I think we heard the term time coupled, multi period economic dispatch, which I think in terms of how that's being solved in the real time market, or how it's being used for the actual real time settlements, I believe only New York ISO and California ISO use a time coupled multi period economic dispatch for the real time market settlement.

So you know an important thing to mention, a lot of good discussion in the previous question about this already. It's important to mention that it is a good solution in its current form. It only meets the needs for known conditions, not unknown conditions, so I think that's very important. The other is that generally in these models do a better job of preparing for that expected ramp needs than a separate reserve product would be.

In terms of reliability and economic efficiency, and that's because these multi period time coupled models also are evaluating the costs of holding capacity for the ramp, as well as the costs of deploying that capacity to meet the ramp, whereas a flexibility product is only in its general form, only evaluating the cost of holding that capacity, so that's an important part.

So I wanted to clear that up, but I think it's really that the question of binding in advisory intervals is something that we thought a lot about, and I want to share a little bit of that here and probably more so with the comments afterward. So you know again I mentioned that these time coupled multi-period models do a great job of providing schedules that can meet expected ramp needs to enhance both reliability and economic efficiency.

However in its current form there is a price formation challenge in the two ISO's that use multi-period models to clear the real time market I believe that both only use the prices and schedules of the first interval for settlement. And the reason this may cause issue is that during the ramping period where a resource is backed down in the binding interval, in order to meet the conditions in the future interval.

It's very important to recognize that you know not only are these multiple period models looking ahead to see what is going to happen in the future, but that future may affect the decisions for now, and that's the time coupled nature of that. But so essentially what happens in this case is that the price of the first interval is depressed, which gets a resource incentive to back down in order to meet that future interval.

And then the price of the second interval -- let's just use the two interval, is actually going to be high because that's the need is to ramp up to that second interval. So this all actually looks pretty well until what happens is that once that second interval becomes the new binding interval, all of the information -- not all of it, but the information is mostly lost from that previous first interval, which means that price, that high price may not actually show up, especially if the anticipated ramp does not result as high as it was anticipated.

It's important to know you might think well why should the price stay high if the ramp does not materialize? And I think for the most part that's true, except for the fact that you have made the decision already for that for one or more resources to back down in order to meet that upcoming ramp, and therefore they may not have the incentive and may have some profit that's impacted.

So there are a few options to actually utilize the fact that multi-period dispatch has superior economic efficiency and reliability benefits, you know, with the exception it has this price formation issue, and you know there are a few ways to meet that. I think ISO New England, Jinye may talk more about having, doing multi-interval settlements, so essentially settling on all of the intervals of that multi-period.

There's also another option of essentially taking the constraint shadow price of what's happening, to actually utilize that as kind of a reserve price. And you can do that and actually make it so it's more aligned with what a reserve price should be, but you have more of the benefits of a multi-period dispatch which actually as I mentioned is superior to using a separate you know reserve product, like a flexibility product for expected ramp capability.

So the question of unexpected you know, being able to posture your resources for what may happen, I think you know we believe that a multi-period economic dispatch can do that as well, and actually price it in a way that can provide the right incentives, but this hasn't really been proven yet, so I think there's more work to be done.

So in any case, it's just a lot of information there. There is this price formation issue that can be resolved through at least two solutions, probably more, and we think that would be an efficient way of ensuring you can get the right incentives out and also meet your reliability and efficiency benefits for the time coupled multi-period dispatch, thank you.

MR. DAUTEL: Thank you Erik. Next we have a hand raised from Dr. Angelidis.

DR. ANGELIDIS: Thank you. So I think Erik really covered these two cases. I just want to add a few more things here. Sometimes you see this effect of system conditions not materializing in the future intervals that you have in your optimization horizon, particularly for further intervals into the future.

In the California ISO market the five minute real time dispatch looks at the 13 intervals into the future, and we have seen occasionally this effect particularly for energy storage resources that they have superior ramping capability, so they move very fast. They are not constrained by ramp capabilities, so they're dispatched so that you have a lower operation cost for the system for the entire time horizon, although you only settle the first interval typically which is the binding -- the financially binding interval.

The results for the other intervals, although they are advisory and you don't settle them, their cost is part of their objective function to minimize the entire objective function of the entire time horizon, and that's why Erik did say that you know your future conditions do affect your financially binding interval discharge because they're all stringed together with ramp constraints.

So the issue of trying to solve this we're looking into solutions particular for energy storage resources, and maybe later on we'll talk more about this, we'll talk about more of those. But perhaps for energy storage resources that they don't have intertemporal constraints, they don't have commitment costs, probably a long time horizon is not that much useful for them, so maybe the objective function can limit the optimization in the first few intervals, the three intervals, and they'll have a cost of dispatch for the remaining of the time horizons so that we mitigate this issue.

Although it's not all the time. We have seen this occasionally, so it may not be a problem, we're still collecting data and doing analysis on it. The option of actually settling all intervals in every time horizon in every market run, which obviously will solve this issue because now you're settled in the advisory intervals, so you don't have to rely on bid cost recovery mechanisms because your financially binding interval is out of the money for a resource or two, is appealing as a theoretical solution.

But practically is very challenging for the example that I mentioned in the market for the five minute market you will eventually have to settle the same interval up to 14 times. That's a lot of settlement work, not only for the ISO, but also for the market participants that they settle with. So this remains a challenge that we still need to face, thank you.

MR. DAUTEL: Thank you very much. Next Dr. Wang.

DR. WANG: Yeah. I'd first like to address the multiple period model to a multiple period dispatch, and the multiple period commitment. We currently use a single period dispatch model as Erik said, and then we use the multiple period look ahead commitment.

So the multiple period model as commented by previous panelists, has the benefit to pre-position resources for expected or forecasted system changes, but they wouldn't be effective to address uncertainties. So to them regarding still looking at reserve products to more address the flexibility needs. For example, we are looking at the 10 minute ramp capability product, like CAISO does, and they have 30 minute short term reserve. We're also exploring the dynamic reserve requirements to account for the varying uncertainties by time.

So for the binding multiple period dispatch model the resources can be potentially better compensated for their pre-positioning, but there are certainly challenges like Erik commented, and we also discussed in a prior FERC technical conferences, especially when those models run on a rolling window basis.

Like when binding dispatch targets at divisible intervals may not be actually helpful very much operationally because we always send the latest dispatch target reflecting the most accurate forecast for resource dispatch following.

So next what do we want folks look at on the commitment side. Finding the look ahead commitment decisions actually are our target, but I also want to point out that RTOs should be allowed the time to improve the quality of the look ahead commitment, so that we can maintain the efficiency and least cost commitment, especially given the increased uncertainties and the regional diversity.

As we noted earlier we are really working to make sure the input is trusted and accurately capture uncertainty, and also we are strengthening our reserve products to really address that flexibility needs. Also we are in the middle of our market system enhancement, so the binding of those look ahead commitment decisions should be coordinate with our engine schedules. And lastly, I wanted to point out in addition to our look ahead commitment we also run a commitment process from market day ahead to day ahead and the intraday, so for those longer horizons as previous comments mentioned, like there's really a balance between the further you look ahead, the more uncertainty you have.

And also the balance of wait and get closer to reserve the flexibility of shocking the units when system accommodations are improved, or the forecasts are more accurate. So for those longer horizon commitments it makes more sense to keep it as an advisory as we think. Thank you.

MR. DAUTEL: Thank you Congcong. Next we had a hand up from Dr. Zhao.

DR. ZHAO: Thank you. I just wanted to add a little additional comments regarding the advisory in binding multi-period dispatch. So Erik gave us an excellent example using a two period dispatch problem to indicate if we only settle the resources on the first binding interval and then treat the future interval as an advisory interval, not settling them then resources may have dispatchability incentive issues.

So we also have been looking into the multi-period dispatch problem, and then one thing we've been thinking is using the multi-settlement approaches, so instead of you just settle on the first binding interval and then one thing to address the dispatch incentive issue is you settle all the intervals in your multi-period problem. And I think one of the advantages of this is sort of reduce the risk exposure for the market participant, because once the participants are locked into a forward price, and then as you keep on running this multi-period dispatch, and then every time when you settle the market the participants are only settled on the deviation from the previous settlement.

So as a result the participants risk exposure to the uncertainty, forecast uncertainty is only limited to the deviation of the settlement. So besides the incentive compatibility advantage, we feel multi-settlements has also reduces this participant risk exposure advantage. But as George mentioned early I think the biggest challenge in implementing the multi-settlement in production is it just becomes very complicated to do implementation because there are so many settlements you have to bind every time.

So it's a little challenge to actually realize in ISO software, and so and also I think another question is regarding the look ahead horizon right? So California ISO and New York ISO has adopted multi-period dispatch problem which I think is helpful for their system, and however there's always a trade-off.

You would always like to look ahead a little more because in the system there are always some resources needs more than two or four hours look ahead horizon to properly dispatch them, however the longer you look ahead, the problem size becomes bigger.

And so ISO New England also has this research work that we sort of considering a coordinated multi-period dispatch approach. So in essence we can try to keep the small dispatch problem size, trying to shut off a limited computational burden, but while keeping the size small, we wanted to introduce some information from future look ahead horizons into the current short look ahead dispatch horizon.

So in this way sort of we want to sort of have a smarter, better informed, short dispatch decision, and on the other hand we can also incorporate some estimated opportunity costs, and into the pricing problems so that when we have a dispatch solution to the resource, the pricing itself also supports the dispatch solution which trying to avoid some dispatch incentive issues. Thank you.

MR. DAUTEL: Thank you Jinye. We'll go to Arne Olson. Mr. Olson go ahead. I think after this we'll go to another question just to make sure we get through the other thoughts also, but Arne you're next and go ahead.

MR. OLSON: And great thank you. Yeah I just wanted to I guess empathize and reiterate the need to start thinking about multi-settlement periods, especially as we move more and more towards a future in which many of these products are being provided by energy storage, and the cost that energy storage has for providing these services really is fully encompassed by its opportunity to you know buy low and sell high over the periods in which the market is settling.

So this will increasingly trend towards a problem of managing the state of charge of your aggregate storage fleet, ensuring that you have both enough downward and upward capability to be able to absorb real time fluctuations. But at the same time I want to maybe make another little pitch for the potential to solve some of this through a reserve product.

I think what we have now with an optimization that encompasses multiple periods, but a binding settlement only for the first of those multiple periods is a bit of muddying of the marginal cost signal. We don't have a clear signal for the marginal cost of serving additional load during the current interval. We don't have a clear signal for the marginal cost of serving load over multiple intervals, at least not one that we're settling on.

So a reserve product, in addition to the short interval energy price can allow the short interval energy price to reflect more precisely the marginal cost of an additional increment of load in that interval, but also in the cost of uncertainty, and the cost of the need to reserve capability to manage net load variability and uncertainty over those future intervals.

So those really are separate cost functions, cost drivers and then that way they would be settled and the costs of those would be seen and felt by the market separately.

MR. DAUTEL: Great, thank you very much. I might just pause before we move on to the next question to see if there's any raised hands from Chairman Glick or any of the

Commissioners, otherwise we'll move on. I'll just pause a second. Okay. Noting that then we will move on. Alex will take the next question, thank you.

MR. SMITH: Thanks so much Tom. Panelists our prior questions that concern general modeling enhancements for commitment and dispatch. For this question we'd like to move to modeling enhancements related to specific technology types. To what exact can software enhancements for modeling specifically technology types, such as multi-configuration modeling of combined cycle units, or advanced modeling of storage resources, and others, help address the system's changing operational needs?

Please raise your hand to respond to this question. I see a hand up from George Angelidis, please go ahead.

DR. ANGELIDIS: Yes thank you. So there are two resources that require specialized modeling. And you mentioned the combined cycle, and it's a little bit more general. It's resources that they have multiple states of operation. Because each state has its own constraints, its own ramp capabilities, its own capacity range, and even its own cost. The cost is different for operating in different states.

Having a multi-state model in the market is extremely useful to capture the characteristics of the resource so that you have an optimal dispatch that both reflects the cost of operating the resource, and its capabilities so that you have a feasible dispatch, and then your market can optimally position these reserves in the best state that can address the system conditions you can see in the market horizon. It is a model that is challenging from a performance point of view because you have a lot of binary variables that are introduced in the problem.

Each state has its own binary status, and you know, as you know when you increase the binary variables in your problem it becomes harder to solve, so it's always a challenge to introduce multi-state models, particularly if the states are many. There are some combined cycle resources that they have multiple states, many states, and these are the most difficult to solve.

So that's about the combined cycle and the multi-state. I believe it's important to have a model that addresses this in the market, and the other resource is the energy storage resource. Energy storage resources they have up to two states charging and discharging, and you may need to separate them and treat them differently in your market because there is usually around the efficiency that is less than 100 percent when you model this.

Usually the charging state, the energy that you put in the reserves, some of it is not available to be dispatched because it's energy that is lost. So that's not too complicated, that you have binary introduced for storage resources. I think the more complicated part that requires a lot of work is that your traditional generating resource model is not sufficient to capture the characteristics of the costs of an energy storage resource.

First of all for the characteristics it has special constraints that you don't see in other resources like energy limit constraints, which basically require you to in the market to calculate and monitor the state of charge in the device so that when you dispatch optimally this device you take into account that the state of the charge is there to meet the schedule, and also if there were ancillary services, there is energy in the device to provide this ancillary service, so you have additional energy type constraints in your problem. That's one thing.

The other thing is that the cost characteristics, the operation of the energy storage resource is different than the cost characteristic of a regular generating resource. The cost is not really a function of the power output is more related to how much storage, how much energy stored in the resource. It's more for function of the state of charge.

We know that batteries that are you know almost fully charged, or almost depleted, so at the edge of the state of charge range, they have a higher cost of operation. So you can only capture this if you have a different cost model for this resource. You have to develop something specific for energy storage resources.

So there's still research that is going on on this, and we have been looking at potential models for storage reserves in California ISO we have several initiatives coming up on this, but it's definitely something we have to look for in the future, because more and more of these resources become available and penetrate the system, so we have to have accurate models for them, thank you.

MR. SMITH: Thank you George. Next I'll call on Congcong.

DR. WANG: Yeah. Overall the enhanced resource modeling to help exert more flexibility from those resources. The past couple years MISO developed an enhanced combined cycle modeling and accessed 14 to 34 million production cost savings, really by allowing those resources to more fully and accurately offer their capabilities and cost into the market, because the combined cycle resources their maximum minimum operating limits, their ramp rates, all vary by configuration, and they're operating mode or transitioning on that corner.

So the traditional model restricts combined cycle owners to offer those variations, and the configuration based model more actually captures these capabilities. And similarly, our enhanced combined cycle model could be generalized, potentially expanded to other resources like storage, a hybrid standard for example.

Like George commented, and allow RTO to use their look ahead software to better optimize their energy limits, and allow better use of these resources when most needed. Lastly, I wanted to note another source of flexibility, the demand and response resource. MISO currently has about 14 gigawatt load modified resources, that we can only access during an emergency, so if we can better model these resources to access them through markets, that will really allow us like more ability of flexibility.

MR. SMITH: Thank you Congcong. Next Erik, please go ahead.

DR. ELA: Yeah, yeah, just to add on to some of the comments so far on this topic. You know I think everyone has kind of said, and I agree in theory you know adding granularity to the characteristics of different technologies and how they interface with the market has economic and reliability benefits.

And I think it's useful to say that we discovered this initially when we introduced unit commitment and three part bidding. That is a unique participation model for you know traditional technologies, but that's you know, a unique participation model.

Europe has gone a different way. They don't include three part bidding for the most part. So you know we sort of discovered that, and I think we continue to, and it's important to say that you know while that looks very well in theory, and of course we see the benefits from a system perspective, there's always reasons why you know maybe the granularity, the detailed model is not preferred, and we hear that sometimes from the community, and some of the hybrid and storage participation models, you know which are analogous to the combined cycle you know configuration base model versus a simpler thermal model.

So I think it's important to recognize that we can capture a lot of these characteristics and constraints of the technology within the market clearing models, but we cannot capture them all, and you know including non-linear characteristics, other sort of internal characteristics that we need to allow for the assets to be able to you know have that flexibility to reflect those into their bids as well.

You know I wanted to close on this question as you know I think the challenge that I think we all recognize, and I think the ISOs on the panel would certainly agree to is that it does take time and money to develop these capabilities for each technology, and again the software may not be able to handle some of these complex models.

So it comes down to how do you prioritize you know whether to focus on advanced combined cycle models versus advanced hybrid or storage models, or advanced demand response, and you know and so forth. And that's a challenging assessment, the thing that I think we've been thinking about a lot is that you know a lot of times there is some cost benefit assessments that you can do to see you know who is going to be using this, you know, how much benefits would we see in terms of economic efficiency, or reliability?

Are they required? And sort of use that to help prioritize and you know think through you know what's the cost of developing the software. What's the cost of the stakeholder discussions to get to a point where everyone agrees upon, and how many people will use this? How many market participants would use this, and sort of you know thinking about those prioritization processes because you know it's you know we always hear complaints of oh, why aren't we doing this, why aren't we doing that, and we should recognize that it does cost money, and sometimes we build some fancy models that aren't used, or may not have the benefits that are realized.

So it's important to recognize the benefits are there in these granular technology specific models, but you know we need to think about who's using them, the priority of which ones will provide the most benefit in terms of their usage, and also the computational issues. We don't want to build something that eventually we won't be able to solve our models in time, so yeah thank you.

MR. SMITH: Thanks so much Erik. Next I'll call on Jinye, please go ahead.

DR. ZHAO: Thank you. I just want to add a comment regarding the energy storage models. So currently in ISO New England in the day ahead commitments, as well as intraday commitments, we sort of use so-called self-management of our state of charge model for energy storage, so meaning these commitment models really don't track the state of charge for energy storage, depending on their cleared charging discharge solutions.

So, so far it has been working well in ISO New England, and however the concern is if in the future there's a large influx of storage resources entering to the market, so we are talking about more than several megawatts of storage into the market. So it's become a little scary that the commitment software don't have a very good visibility of storage state of charge.

So this is sort of a call for we need to develop, enhance the current storage model to have an ISO management of SOC type of model for storage in addition to the current self-management of state of charge model. So Erik mentioned earlier we need to start off with a trade-off which kind of enhancements we should do first.

I feel it all depends on each region's resource mix, and then depending I think for New England, depending on the penetration of storage resources in the system maybe we are forced to sort of have to develop some proper SOC management model for storage resources. Thank you.

MR. SMITH: Thank you so much Jinye. Next I'll call on Arne. Please go ahead.

MR. OLSON: And just to respond very briefly to that last comment. I mean again as I said earlier I think this whole problem is going to evolve very quickly towards management of state of charge, as storage provides a larger and larger proportion of these types of flexibility reserves, or of you know ability to meet net load variability over various time scales.

I think it's really important to incorporate state of charge into these models as quickly as possible, and I think we'll see storage development happen maybe more quickly than people might have expected, at least I would have said so before some of the supply chain issues that have emerged recently.

The last comment I'll make on this is that I think we'll see a proliferation of various different configurations that we should also be prepared for. So we are already seeing lots and lots of storage, tent storage, hybrid projects in the southwest, and those have different amounts or different ratios of storage capacity to solar capacity, and different ratios of storage duration.

We're seeing hybrid storage and thermal resources, so we'll need to make sure that there's a way to have those reflected I the market models and optimized and being made available for the system. Thank you.

MR. SMITH: Thank you so much Arne. I'll call on Congcong again. Please go ahead.

DR. WANG: Thanks Alex. I want to follow-up with Erik's comment on the challenges and really emphasize the computational challenge when we enhance the resource modeling. That's something we experienced and when we developed the combined cycle model, we have to limit the number of configurations because of computational challenge.

And also like although we see very promising benefits from the optimizing the state of charge pumped storage resource through the research, computational challenge is another difficulty. That's why today like in New England, with our energy storage resource model market participants, many things are still charged by themselves, so that's really an important piece we need to look at on the computational side. Thank you.

MR. SMITH: Thank you Congcong. I'll now ask a follow-up question. Many of you have mentioned the challenges of implementing a lot of these software solutions, and a few of you have commented on the costs of those solutions. We've also heard in other panels about there being a difference between where the software is now, and where we'd like it to be, and the costs associated with getting it there.

And would any of you like to comment on the cost to introduce some of these enhancements, especially in light of where current RTO and ISO software stands, and the industry conditions around software upgrades, getting contractors to perform the software upgrades, et cetera. Any comments on the theme of the cost of some. George I see you have your hand raised. Please go ahead.

DR. ANGELIDIS: So although we cannot give you comments about the costs specifically, but you know it's one of the market enhancements that you have to perform to improve your markets, and it's always something that you can do a lot that you can do to improve your markets.

There's no shortage of enhancements you can do in the market. You just have to prioritize everything based on importance, what benefit versus cost analysis you can do.

And how you can provide a better service to your market participants and to your operators.

And in our case for reliability functions because we're also the reliability coordinator. So all of this will have to come together, and I think the cost, unless it is prohibitive, it's justified if there is sufficient benefit to it, and it's all up to really ranking your projects and placing the proper significance based on the outcome that you expect to have.

So I think cost, unless it is really prohibitive, it's a secondary consideration. We're always struggling having the right priority among the initiatives, thank you.

MR. SMITH: Thank you George. Erik I see your hand raised, please go ahead.

DR. ELA: Yeah. I just I think you know obviously that cost is going to differ based on software vendor, and everything else. The one thing I would definitely encourage is that when doing any of these cost benefit analysis on an advanced participation model, as an example, or any sort of software change I guess, maybe in particular to the technology ones, is to have some sense of what the participation might be.

So you know of course we can look at you know throwing lots of you know these technologies on the system, and look, we'll save millions of dollars. You know getting some feedback from potential market participants, and existing market participants. Will you use this? Will you participate? And factor that in to what the benefits are, and then you know I think that can help in terms of the benefit side, and then the cost side you know of course can be evaluated with the software vendor.

And also stakeholder time, because that's not something to be ignored is that takes a lot of time from stakeholders and the ISO, and the analysis and so forth.

MR. SMITH: Thank you so much Erik. In the interest of time we'll now move to our final question, and I'll turn it to Tom to ask that question. Tom please go ahead.

MR. DAUTEL: Thanks Alex. The final question, can multi-day ahead markets or hour-ahead markets help address operational flexibility needs in RTOs and ISOs? What's the objective of such approaches, and are there potential drawbacks? Okay. I see George Angelidis go ahead.

DR. ANGELIDIS: Thank you. So I think we provided I mean every panelist has provided sufficient justification here for hour ahead markets, multi-interval markets in real time. I'm not going to comment on that anymore, but on the multi-day ahead yeah, I have some comments on that. So from a market perspective, a multi day ahead setup is really useful only if you have what we call very long start resources in your system.

So it's really ISO specific because if you have resources that take more than a day to start up from a cold state, you cannot really optimize them with a 24 hour market. So extending the market for future days will provide you the opportunity to commit this optimally. Now, you have to weigh in the benefit of that versus the implementation cost and the performance cost of having additional days in your day ahead market horizon, and it also depends, as I said earlier, to how much capacity you have in your system in these resources, with, that need this market treatment, and there may be alternative ways to commit these resources through an out of market process.

That's not the best case, but if you only have a few resources like that maybe it's a good compromise. Now this is from the market prospective. Now there are other reasons why you may want to run a multi-day market, and that is reliability. You may use the advisory subs for the additional days to do a reliability assessment of needs for your system.

In terms of coordinating outages if your system is stressed for a future day, you may need to postpone outages, so there is some office coordination work. You may run a reliability analysis with contingency analysis to identify weaknesses that your system may experience in future dates that you need some time to work on.

So these are functions you know that relate mostly with reliability coordinator, which you know in our case in the California ISO we're actually using the results of the market to run reliability coordinator functions and assessments. There's operations engineering groups, that they look at the results for future days, and then perform analysis and studies. So from that perspective they're useful.

From a market perspective again it's really dependent on how many very long start resources you have. So you have to weigh in everything. Thank you.

MR. DAUTEL: Thank you. I think Erik Ela was next. Erik, go ahead.

DR. ELA: Yeah I have just kind of an interesting comment. We had a panel session maybe a year ago with some ISOs that was called 15 Minute Day Ahead Markets versus Multi-Day Day Ahead Markets, Which is the one that's better, or something like that. And there was just kind of an interesting you know perspective.

And we got in some good conversations there. But I thought you know one of the things that I try to do that I thought I would just mention for this discussion is I use this exercise where I think about you know if you had infinite computing power, and infinite data availability, what would your market model look like? And you know it might be you'd have one second intervals, you know, with a look ahead of a week or a month ahead.

And multiple scenarios and everything else, but then you sort of look at that and say okay, you know I don't have all this data. I don't have all this computational power. Which of these things should I take away that you know provides the least benefit, but maybe has the greatest, and doesn't have the data to support it, or will have the greatest impact on you know computation.

I sort of keeping taking these things away to see which you know will lead to the greatest benefits. It's almost like solving you know, getting your optimization problem, you have to do an optimization problem and say what's the most value I can get subject to the fact that I have you know finite data, finite computation time.

So that was just nothing specific towards the multi-day ahead and hour ahead, but I just wanted to provide that quick comment as kind of a useful exercise that helps us sometimes.

MR. DAUTEL: Great, thanks. That's very meta. You have to optimize your optimization. Okay. I think Congcong was next. Go ahead.

DR. WANG: Yeah, so MISO currently doesn't have a multi-day ahead market or hours ahead market. I was actually waiting for George to comment on hours ahead market. But we are actually looking at multi-day ahead market, so I'll add more on top of what George said.

The objective of a market is really to better procure resource availability and provide better market signals for resource to schedule their outage, procure fuel, or even schedule extra transactions, especially important for an RTO like us that is currently supplying margin, and the bigger long needed units.

However I want to note a few challenges we are identifying. The computational complexity is the big one, given the longer look ahead horizon. Then the resource offer accuracy, and also other input quality also is challenging, like even the topology of transmission constraints. They are all affecting the quality of the market outcomes.

And finally, the market mechanism needs to be carefully defined so that the market can help procure and commit long lead units, but also we maintain that flexibility with the shorter lead units, so that we can wait until getting closer to real time to schedule those units and uncertainty is reduce.

So before we get to a multi-day-ahead market as a pre-step we currently provide the market the operating margin forecasts to our market participants, really to provide them the better visibility of system conditions, and also help their scheduling of their outage and other planning. Thank you.

MR. DAUTEL: Thank you very much Congcong. Arne Olson is next. Go ahead. I think you're muted Arne.

MR. OLSON: Thank you. Just very quickly there is already a lot of information out there to the market to help inform multiple day ahead commitment decisions, and in terms of the bilateral transactions that are you know probably on ICE or in some of the other platforms.

I would also just note that we're moving more and more towards a world in which there are fewer of these three day ahead start type of machines, and more and more machines that can start very, very quickly. And then the last point I wanted to make is that I think it seems to me that some of these multi-day initiatives are as what George said earlier, really being more of the reliability problem than a market efficiency problem.

And I want to make sure that we keep those two problems separate in our mind. In particular in ISO New England it seems that the fuel security issue is really to me more of a resource adequacy issue that they have just had difficulty addressing through their forward capacity market, and so perhaps the multi day head fuel security initiative is a way to address that sort of lingering issue coming out of the capacity construct.

But it is as George said, a reliability issue, and less of a market efficiency issue.

MR. DAUTEL: Great thanks. So George Angelidis is next, go ahead.

MR. ANGELIDIS: Thank you. I just wanted to respond to Congcong. I guess she was expecting some comments on the hour ahead market, and I didn't comment on that. So yes, the hour ahead market is important as you know we all said for positioning resources, but there was something special about the hour ahead market, and this is intertie schedules.

In the California ISO we do have intertie bids, intertie resources participating in our market. And although this can participate hourly and in 15 minute intervals, in our hour ahead market observes 15 minute intervals in the hour. So you can have a different schedule for each 15 minute interval of the coming hour.

Most of our intertie resource participation right now is hourly, so they need to be prescheduled hourly, so the hour ahead market has the ability to schedule intertie resources before the hour so that they can tag, but T minus 20 is the latest time that they can tag.

And then the real time markets that ran for that hour after that they keep those intertie schedules fixed for the entire hour. So this is one function that the hour ahead market can provide. So you can continue optimizing internal resources, but your interties are already fixed by some hour ahead market that you ran earlier. Thank you.

MR. DAUTEL: Thank you very much. Okay. With an eye on the time I may turn it back to Alex to bring this home.

MR. SMITH: Thanks very much Tom. I'll turn to the Chairman and Commissioners for any closing remarks they have first. Chairman Glick any closing remarks?

CHAIRMAN GLICK: I don't Alex, I just again want to thank you all, but also thank the panelists for the good discussion today.

MR. SMITH: Thank you very much Mr. Chairman. Commissioner Christie I see you've rejoined. Do you have any closing remarks? You might be on mute Commissioner Christie if you're talking I couldn't hear you. Okay. Well with that thank you all for this excellent discussion. Thank you to our panelists, and Chairman Glick, Commissioner Clements, and Commissioner Christie for joining us. We're going to take a short break and regroup at 3:15 p.m. to start Panel 4. Panel 3 panelists please sign out of the Webex meeting.

If you'd like to continue watching the conference you may use the public webcast link on the conference event page at FERC.gov. Commissioners please stay signed in to Webex over the break, but mute your microphones and turn off your cameras until we resume.

Panelists for Panel 4 please sign into Webex. Thank you again everyone.

(Break 3:03 p.m. - 3:14 p.m.)

Panel 4: Out-of-Market Operator Actions Used to Manage Net Load Variability and Uncertainty

MR. HELLRICH-DAWSON: Hello everybody welcome back. Thanks for joining us again for our final panel today. My name is Bob Hellrich-Dawson. I'm from the FERC's Office of Energy Market Regulation, and I'm going to be joined by my colleague Emma Nicholson from the Policy Office.

In this panel we're going to discuss out of market operator actions that ISO and RTO operators currently take to address net load variability and uncertainty, and the impact these actions have on prices and incentives for resources to submit offers that increase the operational flexibility available to the operators.

These out of market operator actions include unit commitments, relaxation of modeled constraints, load forecast adjustments, and other actions that alter operations away from the calculations made by market software. A staff white paper issued last month on this topic noted, ISOs such as CAISO and SPP have stated that out of market operator actions can undermine price formation.

Let me take a minute to remind all of our participants to refrain from discussing the specific details of the pending contested proceedings listed in the supplemental notices issued on September 3, September 12, and October 7, and to refrain from any discussion of other pending contested proceedings.

If anyone does happen to engage in such discussion my colleague Adam Eldean from the Office of General Counsel will interrupt us and ask the speaker to avoid that topic. So thanks everybody for joining us today.

I want to start our first question aimed at our ISO panelists, and if you could please describe what kinds of out of market operator actions your ISO currently takes to address net load variability and why. Have these actions changed or increased in recent years? And if so, what has driven the increase?

Let me first turn to Laura Rauch who is the Director of Settlements at the Midcontinent Independent System Operator, Laura?

MS. RAUCH: Good afternoon and thank you to the Commission for today's conference and a chance to join the discussion. At MISO we do value and appreciate the power of market incentives to support resilience and reliability of the grid. A focus of our market design team is to continue to enhance the market products available to support the needs of our operators to keep the lights on and maintain system reliability.

But at the end of the day out of markets, and especially the use of out of market procedures as we approach emergency conditions, and under emergency conditions, are a critical tool for operators to manage through the uncertainty discussed in earlier panels as managed day to day reliability.

These out of market tools we have found have limitations that should be addressed for market efficiencies. They have impacts on efficient pricing, a lack of transparency when the resources themselves are deployed, and procedures which by their out of market and last resort nature create inefficiencies.

One of the areas that we've experienced as we have seen increasing use of emergency procedures, and emergency out of market procedures, is not that these out of market resources have no value. In fact, we found these resources are a key part of resource adequacy plans for our membership.

But the combinations of uncertainties which we've discussed through this day around load and generation, long lead times for many resources including emergency only out of market resources, and a lack of transparency that we've seen in out of market resources where we don't have the five minute updates on status, and tend to compound coming together with bad case scenarios at the worst possible time.

At best these actions lead towards overcommitment of resources and we don't have perfect transparency or tools to precisely dispatch these resources over the long durations that could be required, increasing those market efficiencies that I discussed earlier, and causing us to inefficiently deploy use limited resources.

As asked in the question these inefficiencies are becoming more concerning as the number of emergency only resources that are on the MISO footprint, both in the sheer magnitude, and the share of the reserve margin which we rely on to meet those needs.

We've also seen an increase in emergency only resources, or emergency only events, which cause us to rely on these more. Ultimately, the ideal state at MISO would be to design and modify markets to remove barriers and create incentives for emergency only resources such as load modifying resources, or LMR, and in particular long lead emergency resources to be committed and dispatched through market operations.

This paradigm enhances market efficiencies through greater transparency, and it still allows us to recognize the value of resources which can respond quickly and are by necessity located behind those emergency procedures. With that I'll thank you for the time today and look forward to the discussion.

MR. HELLRICH-DAWSON: Thank you Laura. Let me turn next to Chris Bossard, who is the Shift Manager for Real-Time Operations in the California ISO. Chris go ahead.

MR. BOSSARD: Hi Bob. Thank you for the intro. As Bob said I am a Shift Manager at California ISO. I've been at the ISO and in operations for about 18 years, and I can speak directly to some of the manual actions that operators take. We do some of these things on a daily basis.

I could talk about some of the most common manual actions that we take. I probably would start in the day ahead timeframe. The day ahead process, day ahead market closes around 1300 time for the following day. We do in real time we do an operations planning analysis of the results. We have engineers that evaluate the results, and they look at the next force contingencies, coupled with all the scheduled outages and forced outages for the following day.

And if we see any issues as far as exceedances on separate system operating limits, based on the day ahead results, then we would manually commit resources as needed, or decommit resources. The ISO, California ISO is currently working on a more automated process for this. It's called the day ahead reliability tool it looks at a more granular 15 minute timeframe for day ahead.

Currently we have it's an hourly market, and on a 15 minute basis we'd be able to capture more of the volatility and ramping changes that could occur that an hourly market doesn't capture. In real time we routinely use load forecast adjustments to balance the system. That's kind of our tool to keep our ACE, our area control error, and frequency within limits.

If we have say a solo ramp off that's unforeseen besides AGC units that are on regulation, our AGC that will automatically respond, our manual action in that case is to change the load forecast up or down to respond to something like a solar deviation.

Also if we had fires out here in California we have fires frequently. It appears that climate change is rearing its ugly head, and we're having drier, hotter conditions out here, so we have fires that develop around our import lines that interrupt our import capabilities.

So in responding to something in real time we might do a load forecast adjustment in that case. There's some more reasons in real time we may change generation commitments that are from the day ahead results, or from our real time results that are generated on a 15 minute basis.

For example, if the 15 minute market produced a shutdown of the resource, it was economic, but our operators identified a reliability need to keep that unit on, they would block or change that commitment from a reliability standpoint.

And then kind of a final thing I mentioned is that we routinely also change the output of generation, generators, individual generators mainly, for similar reasons, for reliability purposes if there is heavy flow on a circuit that's not accurately represented in our market model for whatever reason.

We may change the output of an individual generator, or generators to unload a circuit in that case. Similar with a fire, if we had a fire we may make kind of an urgent emergency phone call to individual generators to bring them online. They're outside of the market results. So thank you for having me, and that's all I have.

MR. HELLRICH-DAWSON: All right thanks Chris. It's a lot of great information. Let me turn to Yasser Bahbaz who is the Manager of Reliability Coordination at Southwest Power Pool, go ahead Yasser.

MR. BAHBAZ: Hey good afternoon. First, I want to thank you and thank the Commission for hosting this topic. I think this is an important topic. As you mentioned SPP is involved in some of the filings to make sure that SPP as a BA, and as an RC, that we ensure that the reliability has what it needs, and we find ourselves and especially after the recent winter event, the best way to go about that is to make sure that there is market incentives.

That's the most straightforward way to make sure and incentivize what you need. As SPP, we are a BA of 51 gigawatts of load with the capacity of wind of 30 gigawatts. That's a fair bit, a fair amount of wind capacity renewable, but 99 percent of it is wind.

And as a BA that I've seen 82 percent penetration peak of wind. We do struggle with a fair amount of uncertainty that we -- (internet dropped.)

MR. HELLRICH-DAWSON: Yasser we might have lost you. Can you hear me?

MR. BAHBAZ: All right. I'm back. There we go now. My phone drops every once in a while. Okay. So as a BA that has high penetration levels of wind, we do struggle with a fair amount of uncertainty considering the relative amount of wind penetration that we have in our footprint, and the size of the BA.

And we don't see that changing any time soon. That probably is the case for a lot of entities, a lot of regions in North America. The amount of generation and interconnection request for wind and solar is increasing to even larger amounts, and so we think this is an important topic, and an important initiative that we need to have to do.

So in fact SPP deploys what we call an uncertainty response team that talks about basically on a daily basis that looks at the amount of uncertainty that we have, that we project to deal with. And then the bulk responsibility of this team is to recommend some amount of capacity of generation that needs to be online, whether it's online or a quick status, or a quick state, or quick start type units for the BA.

And these are all recommendations that are made out of market, and that's because there is not -- we don't have a product that specifically deals with uncertainty. Uncertainty is basically any uncertainty that we may have in the forecast for renewables, any uncertainty we have in the forecast for the ramping of the wind we must deal with as BA to make sure that we're reliable.

And so that is my perspective, considered an out of market action. That's the first step for out of market action I'll talk about here, and that has to do with unit commitments. We'll commit units sometimes out of a study, economically out of a study, but that's after we adjust the forecast to make sure that we do have some capacity, some excess capacity in our market coming out of the market to go with this uncertainty in case the uncertainty does materialize.

And in the cases when it doesn't materialize, obviously the outcome of that is that those generators that were committed may not have been needed, and that results in price suppression and essentially those resources may need to go through a make-whole payment, and that's the -- at least from my perspective, to ensure price transparency in the market.

Second type of manual out of market action that we do take is what I'll call load offset and that's more in the real time. So we do load offset and adjust our obligation before real time, but we do it in real time also. And that's another function of the type of generation that we do have, the renewable generation we echo in real time, and as an echo RTBM runs is 10 minutes ahead, so when you get to RTBM and you echo in ten minutes pass when and if the wind is changing you do have that lag of reflecting the wind capacity, and that causes some volatility, especially when the wind is coming up or going down.

And that essentially forces operators to make sure that the BA is balancing and they do put in some offsets in the system, and those offsets are needed. They're not perfect, they often are not perfect because it does require really proactive action and staying on top of them, not to mention being accurate. And so that does -- that is a minimal operator action that we do take.

Last out of market action that we take is what we call an out of merit energy, and this has to deal with we can do this for various reasons, for the most part it's done for congestion. If there is a volatility and a lot of the time it is from the renewable generation, and RC's are not comfortable with the amount of volatility that they're seeing on the constraint.

They will issue an out of merit energy, and that's essentially an operating instruction regardless of economics. And that can result obviously that is directed out of market type action. They'll do it, but often we do stay on top of them to make sure that it's done once they get in, that they get out of it fast because you know they need to get to some sort of steady state, and get out of those types of actions.

They also do that for non-dispatchable type variable energy resources. We do have some of those, and those are considered out of market actions that we do take. So a fair amount there are various types of out of market actions, most of them are to deal with uncertainty and a lack there of a product for those uncertainties, and one way SPP is addressing that is introducing market products that we can declare an amount of energy that we need for uncertainty, and make sure that that product is compensated for generation that we may need and commit in studies.

So looking forward to a good conversation and hopefully I gave some high level introduction into what SPP does.

MR. HELLRICH-DAWSON: Yeah that's great Yasser. Thank you very much. Let me turn to a set of questions that really are for all of the panelists here. What impacts do out of market operator actions have on price formations in the RTOs and the ISO ancillary services markets first? How often do they occur?

And do you expect the impact is frequently material? For instance, several ISOs have suggested that out of market actions can inappropriately depress market prices, like how often or how much does that happen. Discuss in your own individual experiences and what you see more generally in the markets in which you operate. That would be great.

I'd like to give the other three panelists of course a chance to talk first on this one, so let me start with Liam Baker, who is the Vice president of Regulatory Affairs at Eastern Generation. Liam.

MR. BAKER: Great. Can you hear me okay?

MR. HELLRICH-DAWSON: Yes.

MR. BAKER: Great. So a real quick intro. Eastern Generation, we're owner operators of about 5,000 megawatts between New York City and PJM, and price impact. So you know in a nutshell we see out of market pricing impacts from PJM and New York.

As far as, and I can talk in more detail, but as an owner the reduction in out of market, out of merit actions take it impedes the ability for accurate price formation right. And that's directly correlated with sub-optimal market outcomes. And when you have sub-optimal market outcomes I have less predictability, less stability, and less reassurance that my investments in those assets will have an opportunity to be rewarded.

Where we've seen a reduction in out of market, out of merit actions, particularly in New York, they've done a good job over the last 20 years, we've invested accordingly. You know we've responded to reductions in out of market because we've seen better price formation.

But in other markets in PJM they still have some work to do as we know. But for us, I mean and I don't want to hog up the mic, but for us really it's about where am I willing to put my capital to work, and I'm willing to put capital to work when I have a reasonable expectation that prices I'm seeing in the market products I can provide are being informed by something that is closer to you know workful competition and not the actions of the system operator.

MR. HELLRICH-DAWSON: Great, thank you Liam. Up next let's have Noha Sidhom, the Chief Investment Officer of Viribus Fund. You're also here on behalf of the Energy Trading Institute. Thank you very much. Go ahead Noha.

MS. SIDHOM: Thanks for having me today. You know out of market operator actions and load biasing, they're harmful for both long-term and short-term efficiency of the market. In the short-term these actions are often okay the cost implications aren't known for several days. And therefore the market responds, similar to kind of what Liam said.

In the short-term it's muted, or there's basically a lack of participation in the market because there's too much uncertainty. And in the long-term it's difficult to incentivize investment in infrastructure, and research and development of new technology when those costs are not transparent.

So from a reliability perspective these out of market actions are often necessary, but there needs to be a market mechanism to price these operator actions, and provide that additional transparency. Operator actions must be priced into the LMP and ancillary services, the creation of products like imbalance, reserve product, in CAISO is a step in the right direction.

The ORDC changes that are adopted in some markets, and still in progress in others are also positive steps. We also think a secondary reserve market where reserves above the minimum reserves can be procured and priced would also be beneficial, sort of what we've been saying like LMP 2.0. There's also just more work to be done in this area.

I think ancillary services are often overlooked, and they're a critical tool in an operator's toolbox. I'm really appreciative of how the Commission is focused here. There are also a few pivots I think that the Commission can make in short order to kind of get us some large expedient solution.

You know for about the last decade there's been a really strong focus on capacity markets, and as noted in the March and May 2021 technical conferences, capacity markets are great for resource adequacy, but they don't incentivize necessary investment in new technologies, battery storage, additional flexibility, so we really kind of need to refocus.

And we also need you know price signals and incentives for clean energy and a reliable grid kind of have to work together, so I think some of that cost transparency, very similar to what Liam was saying, you know, we're going to put our dollars where we can see what's resulting in those prices, including emission costs.

I know some of that is out of the Commission's hands, but still something to be mindful of. Value of grid services needed to manage the grid, and energy and ancillary services have to be co-optimized in both the day ahead and the real time markets.

We also really need to view reserves a little bit differently, so our assessment shouldn't just be focused on the single severe contingency, you know. I think that was Arne on the last panel said you know it seems to be reliability issues, and kind of hinted at a little bit of a stronger focus, especially for the gas issues in the capacity market, but really I think we need to be thinking about all the uncertainty we've been talking about today -- renewable forecast errors, load forecast errors, and how do we price in flexibility and those other attributes.

We also really need to increase coordination between demand response at the LDC level, and the RTOs and ISOs. State programs are often incentivized, very necessary DR, and that's a significant benefit. But the ISO just sees it as missing load.

And this could have the effect of depressing prices when the ISO has called on additional resources. So the impact is high out of market payments, that are unhedgeable to load, and therefore result in higher prices for the consumer. And the low real time prices, and the lack of transparency about that response of DR.

So I think some of those like state and federal coordination efforts that the Commission is starting to undertake are a positive. In some markets we see a significant out of market payment, and we don't have a really robust day ahead market, so that's another thing that I think it would really benefit the Commission to focus on is making sure we have a robust day ahead market.

In MISO for example, as they started integrating wind, virtual transactions were a great indicator of the amount of wind that was going to show up. But in some markets we're paying really significant uplift, and as a result you're not getting that robust day ahead signal from the competitive market. The same is true in SPP.

And then while New York has done many things well, they're still zonal on their day ahead market, which really doesn't allow for that really granular price signal to the market. And also then ensuring you have a robust forward curve, and I think FTRs are also a key product to this transition. You know London Economics recently did a study for PJM, and one of the things that they found was between 2017 and 2019, the majority of the combined cycle units that came on as part of their financial arrangements utilized FTRs.

So really you have to have if you want to be in this market, efficiency and maintaining reliability and investment in R&D you have to have a good short-term price signal, transparent prices, and a good long-term price signal. I look forward to the rest of the session today.

MR. HELLRICH-DAWSON: All right thanks Noha. Let me turn now to Bill Fields, who is the Deputy People's Counsel for Maryland's Office of People's Counsel. Go ahead, thanks.

MR. FIELDS: Thank you. Thank you to the Chairman, Commissioners, and staff for the opportunity to be on this panel, and for reaching out to customer groups to be included in this technical conference. I'm Bill Fields, and I'm Deputy People's Counsel with the Maryland Office of People's Counsel.

My office is active in CAPS, the consumer advocates of PJM states, although today I will be speaking just for my office. CAPS is certainly very helpful in getting an understanding of issues like the subjects in this panel, although CAPS would have to go to another level to be truly able to be versed in the technical aspects of this discussion, so my comments today will have to be higher level, but hopefully will be helpful.

Many retail customers are hedged for the rates they pay month to month, although in retail choice states like Maryland, there are policy initiatives for customers, including residential customers to pay variable prices that reflect short-term wholesale electricity costs. As we've seen recently in Texas, that can be very risky for customers.

In Maryland, many retail choice customers paid monthly variable prices which can reflect price spikes in short-term wholesale markets. Whether the retail customer is hedged or not, unnecessarily high wholesale costs will still have an adverse effect on customers. For the most part retail customers see costs such as uplift costs as part of the aggregate of all markets as they show up in their bill.

So any response to those, having those costs should create efficiencies in total to ensure that there is a benefit to customers. In other words looking at this issue in a small context as sort of an issue by issue basis may lose the forest for the trees in that you're trying to solve one maybe small problem, but creating larger costs in total.

So that should be carefully considered in any proposals where we hear about pricing operator actions into the market. I think that will be all for an initial statement, and look forward to the rest of the discussion, thank you.

MR. HELLRICH-DAWSON: Thank you Bill, thanks everybody. Let me take a moment here if anybody has any responses to what we've heard so far. Go ahead and raise your hand and let's see if we can take you in turn. All right. Laura it looks like you're the first one. Go ahead.

MS. RAUCH: I think I would just repeat what has been said. From the MISO perspective we have seen that out of market actions, including some described by our peers can lead to price suppression. Not surprisingly our independent market monitor has noticed that as well, and so we've looked at how do we enhance scarcity pricing based on our evaluation, based on his recommendations. Some of these things are exactly what was discussed looking at the operation reserve demand curve, what is the appropriate value of lost load, and loss of load probability?

Recently we've done some changes to have more administrative options to go and make sure that when we do some of these out of market activities such as implementing load modifying resources, we're valuing at least those megawatts in a way that is reflective of market value, so creating emergency offer floors to avoid price suppression when we have the new megawatts from LMRs enter our markets.

Also looking at revisions to fast start resources to define what is fast start are crucial, both based on out of market actions, and also because some of these out of market actions require several hours of lead time. So making sure that those mesh together is important. Administrative floors may not be our end goal, in fact we are still looking at this, but it is an example of how we need to look very carefully at what are the tools, and make sure that our tools maintain operational reliability end up supporting market efficiency as well.

MR. HELLRICH-DAWSON: Thanks Laura. Noha it looks like your hand is up. Why don't you go ahead.

MS. SIDHOM: I just wanted to touch on something, and obviously I echo Laura's comments, but I wanted to touch on something that Bill mentioned which is you know making sure that we're not increasing prices for the consumer. You know the way I look at it is the load uplift is an unhedgeable cost. We found that in FERC's investigation in the 2014 Polar vortex. LSEs that were largely hedged in terms of energy market prices faced extremely high costs associated with the uplift payments.

The same thing happened in ERCOT in this last winter storm. Folks were hedged, but then they had the really, really significant uplift payments. So I think minimizing some of that stuff actually really ends up saving the consumer a lot of money and allows the load to offer those fixed price contracts at a much more efficient price for the customer.

MR. HELLRICH-DAWSON: All right thanks Noha. Sort of related to that Bill let me follow-up with you a little bit. So as a customer representative, so what do you see are the trade-offs between the loss of market efficiency in the short run with out of market operator actions, and the actual cost savings that might come out of it?

So for instance, if you were to be incorporating more of these actions into the actual market optimization it might be raising the LPM for instance, whereas paying just a single unit outside of the market could actually be cheaper for consumers. Is there a way that you sort of balance that trade-off of short-term market inefficiency, and not necessarily sending the right efficient price signals versus a straight up perhaps savings to the consumer?

MR. FIELDS: Yeah thanks. This really touches on an issue that's frustrating for some of us on the customer side in dealing with these issues and dealing with and being part of the stakeholder process is a lack of information on how different proposals which you know may sound reasonable in you know viewed as singularly but how do they actual impact what total costs are going to be for the customer in whole.

So that would be the first point is that it's very hard to make these kinds of assessments with the limited information that you know a single stakeholder, especially one you know coming from a state consumer advocate office is going to have to make that kind of analysis, or judgment.

I think another point would be thinking about how does this actually incent, or what resources are being incented by this, and what are they being incented to do. We have concerns when about approaches where if you just are increasing a reserve requirement in a way that keeps units spinning and available all the time in order to deal with an additional need for flexibility, well perhaps that's not really rewarding flexibility, and it's actually paying inflexible units.

So I think you know we think about is this providing, is this going in the right direction and providing incentives for the units that the system really needs to maintain reliability? After all these out of market actions are the system operator attaining needed for the system operator to retain reliability, and we have to recognize that the markets are really are based on simplifications of what's going on in the real world if you will.

And so these actions are going to be taken, and maybe even to think about them as out of market may not be the right, always the right way to think of them because it's just part of running the system. So I don't know if those -- hopefully those thoughts were helpful. It's a hard thing to judge kind of how it's going to benefit or harm the consumer in the end, but those are some of the things that we consider.

MR. HELLRICH-DAWSON: All right thanks Bill, that's definitely very helpful. Appreciate it. Any responses to that, or any other hands up? If not I have a follow-up for Liam. You're on notice. So how do the -- sorry, how do out of market commitments affect Eastern Generation's business and operations?

So one could argue that there might be little downside to getting paid via uplift if you are committed outside of the market since your costs are going to be covered. Can you tell me if that assumption is even correct for starters? And second, what would you prefer and why? You know, with out of market commitment.

MR. BAKER: Well I guess if you're at the gravy train you like it, and if everybody else in line you don't like it so much. In many cases our experience, and I'll pick on New York, even though I said they're doing a pretty good job. I don't want to be like a paid commercial for Mike DeSocio, they've done a really good job over the last 20 years improving things, and they're reducing that out of market commitment.

They still do that, but they do it for reasons that are kind of odd. They'll do it for fuel security commitment, and that's all at cost. And they'll do it for other local, very local reserves requirements, and that again is at cost because of old market power rules in New York City. I have to offer most of my products at cost or at zero.

So as an investor, and we are investing in new technologies, particularly batteries, I want to see accurate price formation. You know you're only going to do so well for so long if someone is just covering your costs. Like New York has done a very good job in driving uplift down, uplift for the last several years has been persistently negative, or zero.

Unfortunately, I can't say the same for PJM. In PJM what we see regularly, and PJM to their credit, recognizes there's an issue. They're working on it, fully support that, and appreciate the efforts they made and we're all familiar with some of those dockets, and they're doing that because there is a consistent sort of bias to always over procurement in the day ahead, and that has a downward impact on pricing.

And my point back to anyone who would be asking is the operators, what do you need? Where do you need it and when do you need it? Okay. Why did you pick that resource? And why is the security constrained commitment, an algorithm that we've heard so much about earlier today, not picking the one that you did. You know why do you not have 100 percent faith in the dispatch?

You know we know no dispatch is perfect, but if you can't answer those questions, like what's the what. Is it reserves? Regulations? Fuel security? And the where and the when it can't be modeled because you don't have sufficient accuracy, then you know to Mr. Field's point you know maybe the combination to promote security is in addition to increased and approved granularity around securing those products you need, and no dispatch is perfect, and we don't have machine learning super-duper computers, sometimes you need additional surplus.

You know you need some, but for a certain product in a certain location, but no one likes paying for a necessary surplus, but the alternative, not maintaining reliability, is totally unacceptable. So like New York is working on this, for conditional granularity of additional locational attacking the problem in very specific areas, especially with intermittents coming in in a big way and very congested load pockets.

But it's really going to be a combination of those two. Until we have 100 percent accuracy and a crystal ball or the eight ball, or whatever it is you want to call it in the day ahead, you know, you're probably going to have to live with some additional level of surplus to supplement when you're not right okay.

So the long answer to your short question is in New York you know it's just predominantly at cost, and you know, it is what it is. At PJM I would submit that it's generally negative because we have very efficient peaking facilities in PJM, as peaking facilities go. You know combind cycle is highly efficient, so I want to see good price formation. I don't need the gravy. And then the gravy it's not even that good so, that's the short answer.

MR. HELLRICH-DAWSON: Thanks Liam. The gravy is a little bit lumpy I guess. Let me follow-up with one question, and then I want to turn it over to Emma, so she can ask a couple. But we've heard you're never going to get rid of all uplifts, can you give me a sense -- and maybe this is more a question for the operators. It's sort of what uplift is just always going to be okay?

What out of market operator actions is going to always be okay, you know. Is there a hierarchy of things we ought to be aiming to make sure we get them into the market, and then after that. Again this is a tradeoff of how much money do we spend on trying to fix problems up to the point where the cost is higher than the benefits, you know, there are things that we should be aiming for to integrate into the market, and you know, and then what can we sort of let go because we just know we have to have that uplift as out of market action. Any thoughts? All right Yasser you've got a hand up thanks. Go ahead.

MR. BAHBAZ: Yeah. I'll have a go at that . So yeah I think, and I'm not hearing that we should eliminate. I think that's probably a perfect world, eliminating all out of market actions right because there will always be, likely always be circumstances that we didn't forecast, or didn't project the day ahead. Things happen right?

And so to the extent that we can project a need the day ahead, or as long as we can, reflect those needs in a product I think that's probably the best we can do, at least from where I sit. There will always be market operating, out of market actions that you know things just happen in real time. Transmission elements trip, RCs got to react, and they have to take certain actions.

And those will want to minimize, but they will likely always be out of market action and need, but I think we can greatly minimize what's done today through various products and through price incentivizing, or through designing a price formation that is better than what's done today.

MR. HELLRICH-DAWSON: Thanks Yasser. Yeah Chris go ahead and then Noha we'll have you after him.

MR. BOSSARD: Yeah I totally agree with what Yasser said. I would just maybe add on top of that one thing I see in California is -- and we have initiatives for this, and it is a more granular day ahead market. I think I mentioned this in my opening statement, but you know at least for us having a -- we have errors in the day ahead timeframe compared to real time that I believe are forecastable, that we do have the means to foresee and to take care of in the day ahead.

Having a fifteen-minute day ahead like we're trying to do in California would help us a lot. It more accurately represents the in hour ramping capabilities that we need, that we see in real time, and I think it would instill confidence from an operations standpoint, and it would more accurately represent what we're going to see in real time.

MR. HELLRICH-DAWSON: Thanks Chris. Go ahead Noha. You are muted.

MS. SIDHOM: Sorry. Somebody has to do that first right? So you know I echo what Chris said, the more granular the products, the better, the more confidence you have in the system. Also the more ability for the operators to kind of purview things and see what the model is telling them.

Same with granularity in the day ahead market. I think that stuff is really important as well, or making sure we head in that direction. Bill is right, there's always going to be some level of out of market action like Yasser said, transitional and certainly the trend. There's going to be some things that happen that we just have to deal with in real time, but I really think the closer we get to accuracy and granularity, and the more effort we put into those things, the better price formation that you get that the other investors are looking for --he's not the only one.

And then really we get better prices across the board, and that just has to be a strong focus. I think it's kind of fallen by the wayside, and we've had some interrupted focuses on price formation, but I really think we're at a point, particularly post-Texas where we've really got to do something about this now. We really have to improve our models, our technology, and develop the appropriate market products for this.

I do feel like industry has really been grappling with these issues for some time, just with not a lot of tools in the toolbox. You know I sort of I feel like PJM has kind of gotten picked on a little bit, but they've wanted to make some of these changes for a while, and they really struggle with the stakeholder process you know.

Things like transmission outages for example. In

New York ISO if a TO doesn't properly schedule their transmission and they cause congestion on the grid they have to pay for it. That's not even a staring point with PJM. And SPP I know has really struggled with this issue as well, of getting proper outage scheduling, making sure they can model those things in.

So a little bit different, but also you know I do really feel for these ISOs, they sometimes want to make these rule changes and they just can't. So that's really where we need the Commission's help on some of these issues as well.

MR. HELLRICH-DAWSON: Ms. Noha I think Yasser's ears were burning. Go ahead Yasser.

MR. BAHBAZ: Yeah, so I want to just add to that, and something Liam mentioned with you know. I work closely with operators as a reliability coordination manager, and I can tell you that trust in the system is not sometimes something that they can afford to do. It's one of those things where if you get burned once or twice, they often are very gun shy to wait on the system, to trust the system is going to do its thing right. So we are internally working on two things that as very short-term uncertainty things, and just to make sure that the operators know what's coming in the next 30 minutes, how transmission constraints are being sold in the 30-minute ahead market.

And trust the system. Don't go, don't over react and take action right away thinking that something that's maybe a generator that's going to come on that will solve the problem for you, don't worry about taking out of market action now. And so there are some things that we can do even in real time to make sure that you know it's the appropriate modeling, and it's also making sure that we give the system the chance to do its thing.

So trust is a big deal for operators, and in their eyes they can't afford to take a chance, and so that's something else that I know we're working on, and probably other RTOs too.

MR. HELLRICH-DAWSON: Thanks Yasser. Chris I see your hand up. Why don't you go ahead.

MR. BOSSARD: I 100 percent agree with Yasser. And I would give another example that we run into from a trust standpoint that I know is not good for the market standpoint as far as manual intervention. That is regulation, AGC regulation procurement.

When we have volatile solar days, out here in California we have our peak solar output I believe right now is around 12,000 megawatts, 12,000 to 13,000 megawatt peaks. And on a cloudy day when we have even a slight gray day, which is not that common in California, but if we do have that it's fairly easy to model and expect what we're going to have for solar.

But when we have these more fluffy clouds over a region that are fast moving over regions and stuff, we can have on a five to 10 minute timeframe, we have can have 1,500 megawatts, close to 2,000 megawatts on a five to 10 minute basis ramp off and then ramp back up in the next five minutes.

And I think what we grapple with at the California ISO sometimes is we look at the statistics from a market standpoint, and we say well that only happens rarely. I don't know what the numbers are, but that happens rarely, so we don't need to procure extra regulation.

But then we run into this trust issue that Yasser's talking about that operations we say no, no we do need to get the regulation. That's our only tool that we have right now at this point in time to respond to those solar deviations like that.

And if it happens two days out of the year that's enough. The impact, I guess the impact from a reliability standpoint is severe enough to where operations says no we need to get that regulation, even though from a market standpoint, well it rarely happens 22 days a year. So I just wanted to offer that.

MR. HELLRICH-DAWSON: And that's good to know. Thanks Chris. Let's go to Liam now.

MR. BAKER: So having no experience in either one of these markets gentlemen, but it sounds like you just answered my what question. You know for Chris, the what is Reg. For Yasser what is Fast ramping. Either online or fast ramping reserves that could come online and support wind as it trends down.

You know so the question you have to kind of wrestle with, maybe not you all, but your market operations, market design group is well how do we promote price signals with people to respond with at risk capital to build the kind of assets or invest in existing assets to provide those market products?

Because if you want more reg, and you only have X amount of resource provided, well you only have X and maybe you need to say okay, we'll send a forward price signal, someone is actually going to invest in something that can provide red, like batteries or like God forbid a peaker.

But you know for fast ramping reserves in SPP it might be a unit that says look, if I take the next upgrade package from GE or Siemens or Mitsubishi, I can improve my ramp rate. I can upgrade to the next distributed control system, or improve my ramp.

You know I can bring an old moth ball GT back that has a 10 minute return. You know those are the kinds of things people respond to and put money at, and so that's why, and I feel your pain. And we don't have hardly anywhere close to the amount of wind that you guys are dealing with solar, but we believe the goal is we're going to have that one of these days. So the operators will be struggling with the same kind as you're struggling with.

But I think now is the time to sort of start asking those hard questions.

MR. HELLRICH-DAWSON: Thanks Liam. You know those are good points. Emma, let me turn it over to you to take on some of the next questions here.

MS. NICHOLSON: Thank you very much Bob. We really appreciate the questions you have asked so far. I'm sorry you've answered so far. One question I have is I really appreciate the frank comments from our operators. We understand that you get a lot of -- if you do drive perfectly, you almost get no attention or applause, but if there are issues you certainly get a lot.

So I understand you're wanting obviously driving desire to keep the lights on, and conservative operations, and of course we can see the point from our market participants that would like more transparency and better and stronger investment signals. We'd love to hear from the group what is sort of a threshold model of out of market actions that might warrant in market response?

And what might warrant investing in implementing market reforms? We've seen we've talked earlier how we know we're never going to have a situation where we have zero out of market actions, that's just not feasible with the system and the kinds of systems and operating conditions happening so quickly, but can anyone inform us on -- and as to when are out of market activities significant, frequent, or material enough to start bringing them in the market, and consider bringing them into the market when also considering how expensive and timely it is for stakeholders and RTOs.

What is sort of the threshold level of when you realize that an out of market action significant enough that we need an in-market solution. So any thoughts on that sort of threshold? And I understand reasonable people can disagree on what that is. It would be helpful for us. And I think Liam do you still have your hand raised, or maybe it's from last time?

MR. BAKER: No. And just real quick the way in which we measured it in New York, and again no cheerleading, but it's a function of uplift right? I mean we used to have really outsized uplift, and customers were paying that, and as Noha said earlier it's something that you can't hedge and you just have to eat it and no one likes paying for something that you can't shop around for.

So I think the answer to your question you know what's the threshold of how do I make that, how does that equation get addressed you know to move something out of market into new market? It's what's my uplift to the customers currently, and is it de minimis so it's not worth the effort, or oh my God, that's a lot of money, and you know and it's not going away anytime soon. We need to commit the effort to you know to improve our market design, and to build that system necessary and start pricing that attribute.

MS. NICHOLSON: Thank you very much Liam. Noah?

MS. SIDHOM: Yeah. I would say it's a combination of uplift, and the amount of investment that you're getting in the market. I mean you heard Liam clearly say at the beginning, look the New York ISO doesn't have this, we're throwing our money there.

We're a little bit you know more cautious than PJM because we're not getting the right price signal, and that's what we really wanted, better price formation, so our investors can have some comfort. I mean I can tell you as somebody who talks to investors on a daily basis, they don't want to hear that you're getting a side payment that may go away, those rules may change. They want to know that the prices in the market that you're transacting in are accurate prices.

And that's really the only way you're going to incent some of this investment, and you're also going to get better R and D. People aren't just going to invest in what they know. They're going to invest in what's next if they have some price certainty. I'd focus on those two things, and you're also hearing some of the operators saying not to put words in their mouth, but we don't have all the necessary tools, and that's why we're trying to make these improvements in the stakeholder process.

I really think it is you know sort of incumbent upon the Commission to say okay, we're going to try to make it easier for you to make those changes when we can't overcome all the hurdles in your lengthy processes.

MS. NICHOLSON: Thank you Noha. I think we have Bill Fields, and then Laura Rauch.

MR. FIELDS: Thank you. Yeah. I wanted to just in response to that question reiterate the point that you know from a customer perspective we look at it in -- or at least I try to look at it in terms of what is there going to be efficiency here in terms of total cost. And I think that's what to some extent I think maybe what other people were getting at if you have a small level of uplift or something else, maybe it's not worth it.

But when you look at the market solution, potential market solutions, it should be a primary consideration of whether this is going to reduce total cost. You know if there is uplift cost there maybe it's true that

LSEs, load serving entities can't hedge that, and you know they don't like to pay that and uplift would get factored into retail offers or standard offer service or polar prices.

But you know if you price something into the market that's going to get factored into those retail prices, retail costs as well. And you know maybe it's an easier pass through in some way if it's part of the market, it's part of the uplift, I don't know. But one way or the other I think it's getting passed through to customers. And so I would say that for us a primary concern is going to be whether you're getting a more efficient solution from a total cost basis to the customer.

MS. NICHOLSON: Great, thank you very much Bill, Laura?

MS. RAUCH: I think just to put a different twist on what others say, there's a lot of different ways you can look at this, and ultimately it is the most value delivered to the customer. And that really means that from MISO's perspective we have to align with our members on what those costs should be, what should be the price formation. What should be cost allocation, communication? What are our roles.

My life before settlements was in resource adequacy, and when you're talking about long-term resource decisions market aspects are a portion of that, but there's a lot of other things that MISO doesn't own and should not own, that come into play with that.

The other aspect I'll mention is I think it also depends on what you think the future will have. It would be no surprise to anyone on this call that judging what tomorrow's operations will look like by today's events, or last year's events is going to be very short-sided. I think we've all seen more extreme events.

We all want to use different resource types that will somewhat change our operating paradigm at the end of the day. And for MISO that's why we're looking at something we call our reliability imperative which is how do we look at what our markets should look like in the future? This materialized in resource availability and need. This has materialized in larger market redefinition products.

And so portions of this is less what is our current uplift, but what needs do we see coming in the future, and this has led to things like our introducing of a short-term reserve product that will go live in December based on what we think tomorrow's needs will be.

So I think it's a very complicated question, and the viewpoints that are on this call are the ones that we need to, because it's not something any one market participant, any one RTO can make as solo determinational.

MS. NICHOLSON: Great. Thank you Laura. And Noha I would love to follow up in terms of you asked if the Commission could help with the stakeholder process, and also I think we heard that from other folks. This is a challenging process, it's timely, resource intensive and often times difficult to get things through the hurdle.

We'd love to hear from you Noha if you have any suggestions, and it is fine if you don't, in how the Commission could help with the stakeholders to make, facilitate or streamline any of the stakeholder processes that would make incorporating out of market actions, or market reforms more generally easier to get through.

MS. SIDHOM: Absolutely. I think when the Commission provides guiding principles as you guys do in any rulemaking, that is a good starting point for the stakeholder discussion. So we're not arguing about should we do anything at all, we're more arguing about the details of what we're doing, and I think that is at least gets us through a good portion of that discussion.

You know just really making sure you guys are clear. And okay we want to see this level of out of market action, or this level of uplift is a goal. What do you guys need to do to get there, to get a just and reasonable rate for customers? And what types of products too, incentivizing those products, the same things like you have to have a short term reserve market that is above and beyond single contingency planning, so something similar to what Laura was mentioning.

You know kind of heading it in that direction with the granularity of the products, things like hey, New York, you've been zonal for 20 years. Maybe it's time to go nodal like the rest of the market so that we're getting a more granular price signal. You know things like that are all hugely beneficial.

MS. NICHOLSON: Thank you very much Noha. Does anyone else have any comments or suggestions to that question in terms of making it facilitating the stakeholders or any other -- anything the Commission could do in that regard. Yasser?

MR. BAHBAZ: Yeah I just want to iterate something that was mentioned. It's important that we don't look at just what's today right, and so I think Laura mentioned that, others mentioned that. And so I think it's really important especially in -- I think the grid is changing everywhere else, just not such a SPP, but we need to make sure that five years from now, 10 years from now we have the essential products right, because it's just ramping today, and maybe inertia tomorrow.

And maybe other products that are inverter-based type resources, may not be able to give you -- or we may need to incentivize them or require it, one way or another through the resource adequacy process to make sure that you have what you need coming in to day ahead and real time, or operation horizon.

And hopefully, ideally, that maps to a product right, that maps to a product with quantifiable requirements that have prices set with them right, so you have certainty product, you have inertia products, whatever. And so ideally that is where we ideally should land.

And SPP we're looking at this, and especially after the winter event, we were doing some work before then. We were looking at it from a reliability attribute standpoint, and what does SPP need in the future considering the different futures that we're looking at.

So it's ramp, it's inertia like I mentioned, it's black-start resources, what kind of resource we need out there. Still to be determined whether that's going to be priced. What market rule would have for that if we do have a resource adequacy market for it at all, but certainly in real time operations and the market, it should all map to some product.

Anything we require ideally should just be a requirement and a product, and that is the best thing that I think we can do to minimize out of market action.

MS. NICHOLSON: Thank you. Bill do you have your hand raised as well?

MR. FIELDS: Yes. I just wanted to agree with Noha's point, maybe add to it a little bit. The stakeholder process. I'm obviously familiar with the PJM stakeholder process. There's obviously lots of incumbent resource interest there in the stakeholder process that's going to make it difficult in a lot of ways to get changes, and sometimes it's going to need you know a push in the right direction from the Commission to get those you know new type of initiatives to happen.

MS. NICHOLSON: Thank you all. That was really helpful to hear. I have another follow-up question. I heard a lot of comments about demand response. Is the issue that is limited to emergency demand response? Is there a concern there that when they're called they result in they reduce the prices, but it's not accurately reflected. I'd love to hear some more color on the comments.

We've heard from a couple of different experts on some pricing issues with demand response, and I believe it was emergency demand response, in particular, please correct me if I'm wrong. I think Laura had some comments and Noha. I see Noha you've raised your hand. Can we hear from you followed by Chris.

MS. SIDHOM: Sure. I'm happy to answer that. I was actually I raised my hand in response to sort of the previous question about just resource adequacy issues. And I think resource adequacy obviously incredibly important. You know I think in 2012 the Commission held a tech conference on capacity markets, and back then it was a 90/10 split.

90 percent of the revenue was earned in the energy markets. Now it's probably closer to 70/30 if not more so in the capacity markets. You know just by way of reminder when ERCOT went into this winter they had a 43 percent reserve margin, they had plenty of resources. But I think we really need to focus on is pricing the necessary attributes that provide the necessary flexibility that the operators are looking for to manage this grid, and I totally agree with Yasser.

We have to think about what's ahead. In fact, I think I don't want to say fail to do that, but we're a little bit behind the ball of where I think we really need to be. But to answer your question Emma, my comment about demand response was not necessarily emergency.

Sometimes it is, but it's basically when the LDC's to some state programs will offer significant payments to reduce so at the retail level, but then the RTO really has no window into that, they're not getting communication from the LDCs saying hey, we've called on demand response, we're paying -- they don't even need to say we're paying X amount, but they you know here is how much we expect them because we're providing the right price incentive.

And as a result the ISOs just see it as missing load. So they called on more expensive resources, and so the out of market payments have gone up, but because the load dropped, then the real time prices is suppressed. And so it just seems like missing loads for the RTO, but really it was an appropriate program to have in place. It just wasn't ever communicated to the operators.

So I think that's something that we just need a little bit more coordination on those efforts.

MS. NICHOLSON: Thank you very much for clarifying Noha. Can I hear from Chris next, and then Laura?

MR. BOSSARD: Yeah in regards to demand response at least in my chair, when I'm on shift. If it I utilize demand response I totally get how we have demand response is a market product that has a price. And it sounds like the expectation is it's dispatched in merit order, or economically with other resources.

The issue that we run into, that I run into when I'm on shift on a peak day, is much if not all of my demand response is buried behind emergency procedures in NERC's criteria of EEA levels. And I have to be careful what I say here, but when I'm on shift declaring an EEA of two or higher, to dispatch something economically it's not something that really makes sense from my standpoint.

If demand response was not reportable, whatever as far as to EEA and NERC, and it was just another resource then I would have no problem with it. It just comes -- at California ISO when I'm on shifts if we're going to utilize demand response there's a bunch of other baggage that comes along with it besides market pricing and market things. I don't know if that makes sense or not but.

MS. NICHOLSON: It did, thank you very much. Laura can we hear from you and then Yasser?

MS. RAUCH: Well I think Chris covered a lot of it. From a MISO perspective we do have multiple forms of demand response, including in market units, and ones that are more behind emergency procedures. We see similar questions and concerns with what Noha said, and with what others have talked about with do we have appropriate transparency into those resources?

And so as we think about especially in the future where we might have more forms of demand response, distributed resources, behind the meter generation, load modifying resources in general. I think there is a question on how do we move those to markets because a combination of long lead times and a reliance on NERC emergency operating procedures to access those is a very inefficient way to run

a market, especially when combined with a lack of transparency
because we don't necessary have insight into whether those resources have been called on for local load serving needs.

And so we have less visible than we do with market resources on how much will actually react, or the incremental reaction to a given call.

MS. NICHOLSON: Thank you very much Laura. Yasser?

MR. BAHBAZ: Yeah I think Laura and Chris captured most of what I was going to say on demand response. I'll add another challenge. So I think with demand response there's two tiers right? So there's the market participating demand response. We don't have a lot of those and in fact I know we have some, but they're not participating in the market.

So when they don't participate in the market as far as SPP is concerned, it's a load reduction. And the load reductions in themselves, they cause us a problem of uncertainty within you know, so it's load that we projected that it was going to show up, but it didn't show up by virtue of having a generator that comes on next to it right, that's what demand response is.

So to the extent that demand response comes in front of the meter, or as participating with the ISO/RTO to that extent that's possible then it would be priced. The challenges with that I think is how distributed they are right, and depending on what they're point of Interconnection is and if we need to make sure that they're modeled in the right, on the right transmission on the right point of interconnection because it does make a difference in terms of transmission impact.

All the other demand response if it's not modeled explicitly in the market as dispatchable, then it does become what we call interruptible Curtailable load, and that is only accessible through emergency conditions by specified by NERC. And that's the EEA2 level that Chris was mentioning so.

MS. NICHOLSON: Great. Thank you. I have one final question and given that I think we've heard before and it's sort of unreasonable to expect just given the primacy of keeping the lights on, and how hard ISO staff worked to keep the lights on in reliable energy, and how much we appreciate it as well.

Given that we are going to have certain level of market operator actions that we won't be able to get them all into market, or simply it just takes time to get in the market. We've heard some folks, including Laura you mentioned that maybe there's an in between method of having an administrative price for those out of market operator actions.

And I'd love to hear the group's thoughts on if that's sort of a viable approach, and a short run approach or a reasonable means to address. And then of course like the million dollar question is like what kind of administrative price would you assign to that out of market operator action. So if anyone has any thoughts on that proposal which we've heard from some folks please let us know. And I think we have Liam Baker has his hand raised.

MR. BAKER: No I mean just being in the New York City market you know it's pretty much. It's a market and we get made fun of a lot because it's a lot of administrative constructs. That's one that's so heavily mitigated, so concentrated. So I'm very used to different flavors of demand curves, capacity for reserves, you know, for a whole host of things.

And when they're properly designed you know they can be very effective. And we've had that experience in New York and they can be effective. As far as I'm not economist, but listening to smart ones you know it's a representation of how they value lost load.

Now it's not going to go from zero to the moon because at some point you have to put a value on it, but I mean that's how I understand over time the ISO has broken out its various charge, with the exception of capacity which is based on you know net CONE.

But that's how I understand it, and I think there's a time and a place for them, and I think they can be effective in the absence of having a more -- there's a right you know economic term for it where a more fluid market, a more workable market where you can actually represent the true marginal cost, but a solid representation can be reflected in a curve. I do believe that.

MS. NICHOLSON: Great, thank you very much. Does anyone else have any thoughts on it? Would administrative prices or associated with the out of market operation actions rather than pulling the markets kind of an intermediate step? Scanning our panelists I don't think anyone does. Thank you again so much for your comments and your expertise on this important topic.

We certainly understand as a Commission that out of market operator actions are often an indicator of a potential need for a form, but there's a lot of other considerations, and I think you as this panel have really enlightened us, and the audience as to what those are.

Before we close I just wanted to see if anyone on the panel has another comment or question for their fellow panelists. Yasser?

MR. BAHBAZ: Yeah we can talk about this all day, but I was going to mention something to Liam's point about you know a load reduction is a load loss, value of loss of load. And so to some extent I agree with that. The challenge is that there are other steps in between before we get to load loss that are not priced right.

So we talked about the different emergency levels, and we didn't know it was emergency levels, there are several actions we take including BA to BA assistance from our neighbors and curtailing exports. And so things that we need to think about is that how do we price those things before we get to the loss load, because those certainly would be steps that we take before we get to shedding any load.

So anyway, so there's some logistical and some other I guess I'll call them administrative, but there are some other regulatory side steps that we do need to take, and likely need to price as well as demand respond type actions, who are going to price it as a price loss of load.

MS. NICHOLSON: Thank you Yasser. Laura? I think you're on mute Laura.

MS. RAUCH: Thank you. There has to always be two in this, so I fulfill the second role there. At the end of the day MISO does believe markets work, so a lot of their responses to out of market actions default back to how can we get more resources into markets?

We think that provides efficient signals to maintain reliability at the least cost and a paradigm where we move emergency only resources, especially long lead resources really enhances market efficiency and transparency, helping our members and generators to make more efficient decisions.

At the same time market tools and services are constrained by practical limitations. As we noted before we can't be perfectly accurate, and even talking about how accurate can we get, the market systems themselves can be a barrier in the implementation of tools because of limitations on computational and human resources to bring valuable reliability in market improvements.

So as we look at MISO and balance some of these different competing factors, we are looking at how we maintain reliability via the reliability imperative on market system enhancements. But at the end of the day it is a conversation that we need to continue to have on how do we balance which needs provide the best market signals, and making sure that we're focusing on the right things at the right time to pursue that ideal state, that we'll never reach but always strive for.

MS. NICHOLSON: Thank you very much Laura. Liam, did you have a comment as well?

MR. BAKER: Just real quick to Yasser's point. Yeah like for instance in New York we have a series of steps when you're kind of in a pinch that are not priced. I mean the public appeals, voltage reduction, there's all kinds of things that the operators have flexibility to take, and those aren't price actions, and no one would ask them to be priced.

Until you start getting to you know the day ahead demand response, emergency demand response, and then you start going into your with your day ahead it's mandatory, but they need notice, and end day it's kind of voluntary, but there's all different levels. And my point is there's a lot of steps that we don't worry about pricing, we just have to accept it, that's reality and it's fine. It's totally fine.

But when we get into the real time, when you're calling these resources the ISO does have really good mechanisms to reflect that in the market, so you don't have, and it generally works, where you don't have the bottom falling out of the price when you're really up against it and calling your DR. But it doesn't always work.

But there are a series of steps many which are not present.

MS. NICHOLAS: Thank you very much Liam. Bill Fields.

MR. FIELDS: Thank you. Just wanted to make a brief point about value of loss load. It's a complicated topic. The value is different to different customers. You know a one hour outage is going to be different to between you know a residential customer or potentially some industrial customers, particularly one that's unanticipated.

Now you know something multi days long, or something more extreme is going to be different, so when you look at those, you know, that as a number, just sort of a caution to be thinking about what kind of customer you're talking about and are you really getting the right answer for the system.

MS. NICHOLSON: Thank you very much Bill. Do we have any more closing comments from our panelists? Oh we do. Chris Bossard.

MR. BOSSARD: Thank you. Since we're talking about manual actions by operators I thought you know we're talking about all the kind of negative stuff here and how we can improve. I thought I might share from California ISO kind of a success that we had, especially this last summer as you guys might be aware, we had a brutal summer in the west, and in California with very, very high temperatures, dry conditions and a lot of fires.

So the system was stressed, our power grid was stressed for weeks and weeks, and one of the things coming into the summer that we were anticipating needing to have operators babysit and take care of is batteries, or non-generating resources I believe as we call them also.

And babysitting them from the standpoint that when we get into peak and net load peak they're fully charged, and I believe somewhere I don't have exact numbers, but I believe we were pushing 2,500 maybe close to 3,000 megawatts of batteries, commercial batteries, on our system.

They had already had contracts that were being counted on for capacity, so there was a big concern that it would be available, fully charged to provide megawatts during peak and non-peak. And we went through quite a bit of effort company-wide to build a process and a tool that the operators would use to essentially out of market manually dispatch the units early in the day, late morning, afternoon, to force them to charge during the day when the solar is up and available peak.

Well actually the success in this is that there was some growing pains at first. By mid-summer at least we found that commercially the generators, I mean the batteries. I don't know what they did on their point. I'm not privy to that, but they were bidding and scheduling themselves to where they were charging themselves in the afternoon, and for the most part fully available, fully charged during peak flow time, and discharged. It was a great success I think seeing it, so I just wanted to share that kind of policy thanks.

MS. NICHOLSON: Thank you very much Chris for your views. I think we are all eternally grateful. We love electricity and having this conference would not be possible without you operators, so I think we all understand that how important your job is.

And no one I don't think would accuse you of being bad, but we always strive to do better, and I really appreciate all the great minds here helping us try to continually improve these markets, particularly given the large changes that we all see at the horizon.

And in fact CAISO and SPP are in the middle of large changes, and I think to all the ISO's credit I think there's a general recognition that out of market operator actions can signal market failure, and you independently work with stakeholders to address them through ramp products in California's DAME proposals, so we certainly are really grateful for all the hard work at the ISOs and in the stakeholders to the stakeholder process.

I really appreciate the panel today. I think Noha did you have another comment before we closed?

MS. SIDHOM: I'm just going to thank staff for putting this together, and for everybody for their input. And you know I'm really hoping that we see some expedient action on these issues, because as you know it's very necessary I think for us to get that. And Chris that's a fantastic story. It makes me so happy to hear that all of this is starting to come to fruition.

I mean that's investment in R and D from years ago. Thank you guys, we appreciate it.

MS. NICHOLSON: Well thank you all. To our panelists it's been a very illuminating day for us. This panel, as well as all the four panels I think we've had today I think we're going to go ahead and wrap up this technical conference. I wanted to thank in addition to all of our panelists, we had Chairman Glick, Commissioner Danly, Commissioner Clements and Commissioner Christie participate as well, and we're really grateful for your participation.

And to all of our panelists both days of this energy and ancillary service tech conference you have really informed us a lot about this incredibly complicated and challenging problem, but I'm also -- we as staff are very heartened how many bright smart people are analyzing problems from different points of views so we can crowd source and do good solutions here.

We expect as is typically the case after a technical conference that the Commission holds, that we would issue the call for post-technical conference comments. When that happens, when and if that happens very likely it would be posted in Docket Number AD21-10. And I would also like to thank my colleagues, my colleagues and FERC staff for helping put this conference on, which we had folks from the Office of Energy Policy and Innovation, Office of Energy Market Regulation, Office of Electrical Reliability, Office of the General Counsel, Office of Enforcement, the Office of Information Technology, External Affairs, and Executive Director.

So it really does take a village and we're very grateful to everyone for your participation. And I think that will close our conference unless Bob, did you have any -- sorry. Okay, thanks again everyone for your time today. We really appreciate it. And Capital Connection you can close the feed.

(Whereupon the conference concluded at 4:37 p.m.)

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:
Technical Conference on Modernizing Electricity Market Design: Energy and Ancillary Services in the Evolving Electricity Sector

Docket No.: AD21-10-000
Place: Washington, DC
Date: Tuesday, October 12, 2021

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